Decision **03-12-061** **December 18, 2003**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing a Market Structure and Rules for the Northern California Natural Gas Industry for the Period Beginning January 1, 2003 as Required by Commission Decision 01-09-016. (U 39 G)	Application 01-10-011 (Filed October 8, 2001)

OPINION REGARDING THE GAS STRUCTURE AND RATES FOR PACIFIC GAS AND ELECTRIC COMPANY FOR 2004

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OPINION REGARDING THE GAS STRUCTURE AND RATES FOR PACIFIC GAS AND ELECTRIC COMPANY FOR 2004

I. Summary

Pacific Gas and Electric Company (PG&E) filed the above-captioned application on October 8, 2001. PG&E's application requested that the Gas Accord[1] structure and rates for its gas transmission and storage system be extended for two more years (through the end of 2004) pending the resolution of PG&E's bankruptcy filing.

In Decision (D.) 02-08-070, we approved a settlement by the parties which extended the Commission-approved market structure, rates, tariffs, and terms and conditions of service for PG&E's transmission and storage system by one year. Under the settlement, the market structure for PG&E's gas transmission service was extended for the period from January 1, 2003 to December 31, 2003, and PG&E's gas storage service was extended for the period from April 1, 2003 to March 31, 2004. Due to the adoption of the settlement, the issues regarding the gas structure and rates for the period beginning January 1, 2004 were unresolved.

Today's decision resolves the gas market structure, rates, and terms and conditions of service for PG&E's natural gas transmission and storage system for 2004. PG&E and the other parties proposed for resolution a number of structural

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[1] The Gas Accord market structure and rates for PG&E were originally approved in the Gas Accord Settlement Agreement that was adopted in D.97-08-055 [73 CPUC2d 754]. That settlement, and the time period covered by the settlement (through December 31, 2002), is commonly referred to as the "Gas Accord." In addition to the market structure and rates, the settlement addressed PG&E's role in gas procurement for core customers, as well as a number of issues concerning the Line 401 project. Certain provisions of the Gas Accord were modified by D.00-02-050 and D.00-05-049.

and policy issues, as well as cost and rate design issues. Appendix B of the decision lists a matrix of the issues addressed in today's decision.

PG&E proposed a $453,736,000 revenue requirement for 2004 for its gas transmission and storage systems.[2] PG&E's proposed revenue requirement represents an increase of 7% over the Gas Accord revenue requirement for 2003 of $423,923,000 million. Today's decision adopts a revenue requirement for 2004 of $436,397,000.[3] The adopted revenue requirement represents an increase of 2.94% over 2003 gas transmission and storage rates of $423,923,000.

Today's decision also addresses the various cost allocation and rate design proposals of PG&E and the other parties. Since this decision adopts a cost allocation and rate design methodology that is very similar to what was contained in the Gas Accord, we expect that the gas transmission and storage rates and charges will rise slightly, reflecting the 2.94% increase in the revenue requirement.

II. Background

PG&E's application was filed on October 8, 2001 in response to D.01-09-016. D.01-09-016 directed PG&E to file an application proposing a market structure and rules for its intrastate gas transmission system and storage system for the period beginning January 1, 2003, when most of the provisions of

[2] PG&E had originally requested $478,759,000 as its revenue requirement for 2004. This request was based in part on a higher rate of return that PG&E was seeking to litigate in this proceeding. The February 14, 2003 ALJ ruling granted a motion to strike PG&E's cost of capital testimony from being litigated in this proceeding, and stated that "the parties can use the cost of capital established in D.02-11-027 as a placeholder until a decision on the cost of capital for test year 2004 is rendered.

[3] The adjustments to PG&E's revenue requirement request, to arrive at the adopted revenue requirement, are shown in Appendix A of this decision.

the Gas Accord were to expire.[4] PG&E's application proposed that the existing Gas Accord market structure, rates, and terms and conditions of service be extended for a two-year period, *i.e.*, through the end of 2004, or until PG&E's assets were transferred to the jurisdiction of the Federal Energy Regulatory Commission (FERC) as requested in PG&E's Chapter 11 bankruptcy filing. Protests and responses to PG&E's application were filed.

Following the January 7, 2002 prehearing conference, the assigned Commissioner and administrative law judge (ALJ) issued a scoping memo and ruling (scoping memo) on February 26, 2002. The scoping memo described the primary issue as whether the existing Gas Accord structure and rates should be extended for an additional two years. The scoping memo also identified other outstanding issues, and set the evidentiary hearings for August 2002.

On May 20, 2002, PG&E and 13 other parties filed a "Joint Motion For Approval Of Gas Accord II Settlement Agreement And Request For Shortened Comment Time," and a "Joint Motion To Change The Procedural Schedule For Litigation Of Scoping Memo Issues." On June 4, 2002, PG&E filed a motion to supplement the Gas Accord II Settlement Agreement with the signature pages of four additional parties. In a July 9, 2002 ruling, the ALJ granted the joint motion to change the procedural schedule, and the motion to add the additional signature pages to the settlement. Granting the motion to change the procedural schedule allowed us to focus on whether the proposed Gas Accord II Settlement Agreement should be adopted.

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[4] In D.01-09-016, the Commission referred to the market structure and rules for the period beginning January 1, 2003 as Gas Accord II.

On August 22, 2002 in D.02-08-070, we granted the joint motion to approve the Gas Accord II Settlement Agreement. Pursuant to the settlement agreement, the market structure, rates, and terms and conditions of service for PG&E, which were adopted in D.97-08-055 and modified in D.00-02-050 and D.00-05-049, were extended through December 31, 2003 for gas transmission, and through March 31, 2004 for gas storage. The procedures and guidelines for contracting for gas transmission and storage services, as agreed to in the Gas Accord II Settlement Agreement, were also approved.

As part of the settlement, PG&E and the other settling parties reserved the right to seek a rate increase or to address the structure, rates, and terms and conditions of service for gas transmission and storage services for the period beginning January 1, 2004.

Due to the one-year extension, the issue of what PG&E's gas structure and rules for the time period after 2003 should look like, as well as the other issues identified in the scoping memo, remained outstanding. In ALJ rulings dated September 30, 2002, December 9, 2002, and February 14, 2003, the schedule for resolving these issues was established. The September 30, 2002 ruling directed PG&E to include a cost of service study in its prepared testimony for the purpose of evaluating "what the gas structure for 2004 should look like, and whether the existing Gas Accord structure should be continued in 2004." (ALJ Ruling, September 30, 2002, p. 7.) The ruling also directed PG&E to include a rate proposal for 2004.

In response to the rulings, PG&E filed its "Gas Accord II Amended Application" on January 13, 2003, along with its prepared testimony. PG&E's cost of capital testimony was stricken from this proceeding in the February 14, 2003 ALJ ruling. The other parties served their prepared testimony on February 28, 2003, and the rebuttal testimony of all the parties was served on March 24, 2003. Eleven days of evidentiary hearings were held in April 2003. Eighteen opening briefs were filed, and sixteen reply briefs were filed. Following the filing of reply briefs on June 2, 2003, the proceeding was submitted for our consideration.

III. 2004 Gas Structure and Beyond

A. Summary of the Proposals

The Gas Accord market structure, which was implemented on March 1, 1998, established the rules for providing access to PG&E's backbone and local transmission system, and to PG&E's storage system.[5] The main features of the Gas Accord market structure are the unbundled, tradable, firm rights to backbone transmission and storage capacity. The Gas Accord also established rules and standards for PG&E's role in core procurement. As a result of the Gas Accord market structure, gas marketers, and end-use customers and their agents were provided with a variety of tools to manage their gas commodity and transportation costs. The Gas Accord Settlement Agreement, which is attached to D.97-08-055 as Appendix B, describes more fully the market structure. (*See* 73 CPUC2d at 797.)

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[5] PG&E's intrastate backbone system is made up of large diameter, high pressure transmission pipelines, which receive gas from various interstate pipelines, California gas producers, and storage fields. The backbone pipelines then deliver the gas to PG&E's local transmission system, and to off-system facilities, primarily those owned by Southern California Gas Company (SoCalGas). PG&E's local transmission system is connected to many large end-use customers, and to local distribution facilities which serve the smaller customers. PG&E's storage system is composed of three underground gas storage facilities, which are used primarily to ensure reliable service to core customers. The storage facilities also provide system balancing service, and market storage services such as firm and negotiated storage, and parking and lending services.

PG&E's application proposes to retain the basic market structure of the Gas Accord, with certain proposed changes. PG&E requests that the basic market structure be retained permanently, and that its proposed changes, rates and terms and conditions, as proposed in its application and supporting testimony, be adopted for the period beginning January 1, 2004. The most notable of the proposed changes are the following: (1) reducing the system load factor to 68.4% to reflect its demand forecast for 2004; (2) replacing the single average rate for noncore local transmission service with a four-tiered rate structure segmented by annual usage; (3) establishing a 1-in-10 year Winter Reliability Standard and Winter Firm Capacity Requirement; (4) the roll-in of 20% of Line 401 costs to the core; (5) replacing the current diversion procedure with a curtailment procedure in the event of a supply shortage; (5) selling 4.5 MMDth of non-cycle working gas, the profits of which would be retained by PG&E's shareholders; (6) including in rate base $80.5 million in non-cycle working gas in storage; (7) assigning new storage capacities to balancing, Core Firm Storage, and Standard Firm Storage; (8) cost recovery for the Gerber compressor station fire; (9) balancing account protection for noncore distribution revenues; and (10) imposing bypass reporting requirements on third-party storage operators.

PG&E is proposing to adjust rates for 2004 to reflect updated cost and throughput projections. If PG&E's cost and throughput projections are adopted, along with PG&E's proposals, PG&E's gas transmission and storage revenue requirement would increase from $424 million in 2003 to $454 million for 2004. Under PG&E's proposals, the rate of core customers (*i.e.,* bundled residential, small commercial, and large commercial customers) would increase, on average, by $0.015 per therm. For retail core transport customers, the increase, on average, would be $0.013 per therm. For wholesale core transport customers, the increase, on average, would be $0.032 per therm. For noncore transport customers, depending on the tier, rates would increase or decrease, but the overall average noncore rate would remain the same.

Other parties have also proposed changes to various parts of the market structure, or to PG&E's proposals. The major proposals are: a backbone level rate structure (also referred to as backbone level rate); 100% roll-in of Line 401 to the core; increased demand forecast for electric generation and a higher system load factor; and that PG&E's Core Procurement Department be spun off to a separate entity.

Some of the parties advocate that the Gas Accord Settlement Agreement be extended for another year. Others favor the adoption of certain proposals, and that certain other proposals be rejected or deferred.

All of the proposals mentioned above are discussed in the sections which follow.

B. Continuation of the Gas Accord Structure

1. Introduction

The scoping memo identified the primary issue in this proceeding as whether the existing Gas Accord structure and rates should be extended for an additional two years. However, due to the adoption of the Gas Accord II Settlement Agreement in D.02-08-070, which extended the Gas Accord for one year only, the issue to be addressed in this proceeding is what kind of market structure and rates should be in place for PG&E's transmission and storage system beginning January 1, 2004. As the starting point for the market structure and rates for 2004, PG&E uses the framework that was adopted in the Gas Accord, along with certain proposed changes to the market structure and costs.

The other parties to this proceeding either advocate that the Gas Accord structure be extended through 2004, or that the Gas Accord structure be used together with their proposed changes.

In addition to deciding what the market structure should look like for 2004, the second issue we need to consider is what kind of market structure should be in place beyond 2004, and for how long. Such a matter should be considered so we are not faced with the annual task, as we are doing here, of deciding the kind of market structure that should apply to PG&E's gas transmission and storage systems each year.

To address the issues of what kind of market structure should apply in 2004, and what kind of market structure should be in place for the future, and for how long, we need to consider how the Gas Accord structure has performed in the past, whether such a structure has conferred benefits, whether other viable market structure proposals exist, and whether the changes proposed by the various parties should be adopted.

Some of the parties have advocated that we simply extend the Gas Accord market structure and rates for 2004. Their reasoning for the extension is that there has been insufficient time to adequately analyze the proposals, or that the proposals were not identified as issues in the scoping memo.

2. Positions of the Parties

a. PG&E

PG&E proposes that the Gas Accord structure be continued into 2004 and retained permanently. PG&E contends that the record established that the Gas Accord structure has performed well over the last five years under a wide range of operating and market conditions, resulting in reliable service, increased choices in gas procurement, a high degree of price stability, and the prevention of market power. The prices for intrastate transportation have remained at moderate levels, even during the difficult 2000-2001 period.

The Gas Accord market structure has facilitated the development of the citygate as an actively traded market in PG&E's service territory, which provides customers with additional services and procurement options. As a result of the unbundling of services, cross-subsidies have been reduced. This has led to increasingly transparent prices and values for natural gas at the citygate and for gas transportation on the Baja and Redwood paths.

PG&E also points out that under the Gas Accord market structure, firm capacity rights to the backbone can be traded in a secondary market. This reveals the value of the capacity, and allows those customers who place a higher value on such capacity to obtain that capacity. This reduces or eliminates the uncertainty, gaming, and reduced reliability over pipeline capacity. In contrast, under a market structure that lacks firm capacity rights, capacity may be assigned on a pro rata basis within priority classes during times of limited capacity regardless of the value of use for that capacity.

The value of holding firm rights on PG&E's backbone system is enhanced when market participants also hold firm rights for interstate capacity. This assures market participants that they can transport their gas all the way to end-use customers or to the citygate, and reduces the exposure to price increases for this capacity in the short-term market.

PG&E also asserts that the firm, reliable, tradable transportation rights available under the Gas Accord market structure, together with the adequate capacity, helps to minimize uncertainty about prices and the ability to deliver supplies, which reduces the potential for upstream price manipulation.

In addition to serving Northern California, PG&E's backbone transmission system delivers gas on a firm and interruptible basis to Southern California and other off-system markets under the Gas Accord market structure.

PG&E contends that the Gas Accord market structure sends long-term price signals, which facilitates the expansion of transmission and storage capacity, such as the expansion of the Redwood path by 218 MMcfd in 2002, the commercial operation of the Lodi Gas Storage (LGS) facility in 2001, the Kern River expansion in 2003, and other projects. Having a customer commit to a long-term firm capacity contract creates a price signal because the customers must accurately assess the magnitude and value of their future requirements, and the value they place on price stability. PG&E asserts that under a bundled system, there is little or no incentive to accurately forecast their requirements, which may result in inefficient expansion investments.

During the period of high gas prices in 2000 and 2001, the price of natural gas in the supply basins almost doubled. PG&E points out, however, that the price of intrastate transportation on PG&E's system rose only slightly. PG&E asserts that the Gas Accord market structure has provided firm reliable backbone service, and relatively stable and moderate market values for backbone service, even during times of market stress.

PG&E contends that the Gas Accord market structure is well suited for Northern California with its two distinct backbone transportation systems, access to multiple supply basins, and a variety of end-use customer types. In addition, the market structure has been in place for over five years without any major problems. The structure has also adapted, through incremental changes, to address new customer concerns and desires that have arisen. PG&E contends that the adoption of the market structure on a permanent basis will provide stability for the gas markets, for end users, and for all companies who have a role in providing gas supply, transportation, and storage services. Thus, the Gas Accord market structure should be confirmed as the chosen structure for PG&E's transmission and storage system for the indefinite future, and any new concerns and customer desires should be accommodated within the structure.

PG&E points out, that with the exception of The Utility Reform Network (TURN), no party prepared any analysis or comments opposing the Gas Accord structure, or developed an alternative to the existing structure. TURN is opposed to PG&E's proposal for the indefinite continuation of the Gas Accord structure, arguing that the continuing uncertainty about the future jurisdiction over PG&E's gas assets makes a long-term commitment to any particular market structure unwise. PG&E points out that if PG&E's system remains under Commission jurisdiction, the Commission will need a market structure, and it is within the scope of this proceeding to identify what that market structure should be. If PG&E's gas transmission system becomes subject to the FERC's jurisdiction in the future, the market structure issue would then be moot.

TURN suggests that PG&E, through the use of the intrastate basis differentials, was attempting to demonstrate that the citygate market provided price benefits for consumers. TURN's brief compared citygate prices and transportation rates, and concluded that on a weighted average basis, it was cheaper to hold firm capacity and buy at the border, than to buy at the citygate during the original Gas Accord period. PG&E contends that the point it was trying to make was that under the Gas Accord structure, the intrastate basis differentials suggested adequate intrastate capacity and competitive pricing, reliable firm backbone service, and relatively stable and moderate market values for backbone service even during the period of the energy crisis.

PG&E asserts that when border-to-citygate price differentials exceed transportation rates, it suggests that capacity is scarce, or there may be market power. When the border-to-citygate price differentials are lower than transportation rates, as they were during most of the Gas Accord period, PG&E contends that this suggests there is adequate capacity and competitive pricing. Parties holding firm capacity could have reduced their costs by simply buying at the citygate. However, by doing so, they would have given up the certainty about firm reliable service at a fixed price that the firm capacity holdings provided. PG&E also states that low basis differentials also occur when not all of the firm capacity is subscribed, in which case PG&E might not receive its revenue requirement.

Even if one accepts TURN's argument that the price differential is an indicator of the benefits of the gas accord market structure, TURN's claim that it shows the unbundled citygate market did not provide the benefit of lower prices is incorrect. Exhibit 12 shows that in all but one of the Gas Accord years, and on average over the entire period, it was cheaper to purchase at the PG&E citygate than to hold firm Baja Path capacity and purchase at the border. The Redwood Path capacity was more attractive relative to citygate prices due to the access it provided to low cost Canadian supply available at Malin. PG&E says that the Baja Path comparison is more meaningful, because Southwest supplies were most often the marginal supplies during this period.

PG&E contends that the primary benefits of the unbundled structure have to do with options, flexibility, the ability to ensure firm service and predictable costs, the ability to minimize cost by buying on the short term market (but with higher risk), accurate market price signals, efficient short-term allocation of supply, and efficient system expansion. TURN did not address these benefits, and TURN has not rebutted PG&E's showing of the substantial benefits of the Gas Accord market structure as described above.

b. California Cogeneration Council and Calpine Corporation

Four parties have proposed simply extending the current Gas Accord structure and rates for another year. The California Cogeneration Council (CCC) and Calpine Corporation (Calpine) recommend that the proposal to extend the existing Gas Accord structure and rates for 2004 be rejected.[6] CCC/Calpine assert that we should address in this proceeding those issues that were identified in the rulings, as well as the relatively uncontested issues,[7] and the issues that were fully and fairly litigated such as the backbone level rate, which was identified as an issue in the scoping memo.

CCC/Calpine contend that it may be appropriate to defer consideration of certain of the more controversial and detailed proposals made by PG&E. Such issues include PG&E's storage-bypass proposal, PG&E's proposal to replace the curtailment process with a diversion process, PG&E's proposal to offer long-term contracts for backbone capacity at non-guaranteed rates, PG&E's capital expenditures, and PG&E's proposed Gas Rule 27. Several of these proposals were not identified in the scoping memo or elsewhere as appropriate issues for

[6] CCC/Calpine, along with the California Manufacturers and Technology Association (CMTA) and Mirant Americas (Mirant) sponsored the testimony of R. Thomas Beach. CMTA did not take a position on several issues addressed by the witness. CMTA and Mirant also filed separate briefs from CCC and Calpine.

[7] The uncontested issues include PG&E's proposal to implement a single electric generation class, and to eliminate the cogeneration gas allowance. CCC/Calpine notes that PG&E's proposal to replace the cogeneration gas allowance with the anti-gaming

Footnote continued on next page

consideration in this proceeding. The Commission should also require PG&E to hold informational meetings, which PG&E said it would, about proposed Gas Rule 27, and the storage-bypass and curtailment proposals, before adopting any of these proposals.

For parties to say they didn't have time to analyze the scoping memo issues is disingenuous. CCC/Calpine point out that the parties who now seek a one-year extension of the Gas Accord structure, supported the initial schedule for litigating the scoping memo issues that was set forth in the Gas Accord II Settlement Agreement. CCC/Calpine argue that it would be inappropriate for these parties to now seek further deferral of these issues.

CCC/Calpine also assert that the Commission should reject the parties' arguments that the present lack of certainty regarding the outcome of PG&E's bankruptcy proceeding merits an extension of the existing Gas Accord structure and rates for 2004. Even if the bankruptcy plan is approved in the next few months, CCC/Calpine state that it will take several years to fully implement the plan. By adopting a structure now, customers will have certainty about gas transportation, and PG&E will have certainty about the revenues it will recover and the kind of structure it will be operating in as it emerges from bankruptcy. CCC/Calpine also note that if a one-year extension is granted for 2004, the same kinds of issues will have to be relitigated again for 2005, assuming the Commission retains jurisdiction over PG&E's transmission and storage assets. Such an exercise would be an obvious and unnecessary waste of resources.

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mechanism should not be difficult since PG&E agreed it would adopt the suggested modification of CCC/Calpine.

c. California Manufacturers and Technology Association

The California Manufacturers and Technology Association (CMTA) was involved in the Gas Accord settlement. CMTA contends that the Gas Accord settlement has benefited all gas consumers. The system of firm tradable rights has provided rate and regulatory certainty, flexibility in procurement and choice, and the development of a citygate market. The Gas Accord structure has also allowed gas consumers to mitigate or avoid many of the problems experienced on other gas transportation systems during July 2000 to June 2001. In addition, the Gas Accord structure has provided market signals which have encouraged PG&E and independent gas storage providers to expand gas transmission and storage in Northern California.

CMTA supports the continuation of the basic Gas Accord structure on a permanent basis, with some modifications as described below. CMTA favors approving the Gas Accord structure on a permanent basis because it will create certainty for the transporters of natural gas and consumers. CMTA supports TURN's approach that this proceeding be addressed in two phases. The first phase could determine the structural components, and the second phase could address the rate case aspect of PG&E's filing. CMTA believes that the cost of service data submitted by PG&E warrants further scrutiny in this second phase because there has not been an adequate opportunity for parties to fully scrutinize PG&E's proposed cost of service data. CMTA points out that the Office of Ratepayer Advocates (ORA) agrees that the cost of service data submitted by PG&E clearly warrants further scrutiny, especially for periods beyond 2004.

TURN compared the citygate price to the price of supply at Topock plus the price of firm Baja capacity, and then to the price of supply at Malin plus the price of firm Redwood capacity. TURN asserts that "on average, the unbundled citygate market did not provide the benefit of lower prices." (TURN, Opening Brief at 9.) CMTA asserts that the point of PG&E's testimony was to demonstrate that the Gas Accord brought about a more liquid citygate market and the path-specific scenarios TURN chose to compare to the citygate price do not change that conclusion. CMTA also points out that TURN concedes the accuracy of PG&E's calculation which shows that "the average basis differential from the border to the PG&E citygate ($.28 / Dth) was significantly less than the average undiscounted as-available transportation rate plus shrinkage ($.36 / Dth)." (Ex. 1 at 3-15.)

CMTA states that TURN's attempt to dismiss the benefits of Line 401 for core customers ignores Line 401's contribution to making the citygate a liquid market which, in turn, lowered prices for buyers in that market including core customers. PG&E witness Gee said that PG&E's Core Procurement Department purchased 17 Bcf of gas from the citygate market for 2002. CMTA says that this is a direct, substantial benefit to core customers resulting from the availability of Line 401 capacity.

PG&E also provided testimony that during the crisis period of July 2000 to June 2001, the price of intrastate transportation on PG&E's system "rose only slightly, and reflected competitive pricing and little scarcity on PG&E's system." (Ex. 1 at 3-16.) Although TURN argues that this does not provide a sufficient link between the lack of price spikes in Northern California and unbundling, CMTA contends that PG&E has demonstrated the benefits of the Gas Accord structure to Northern California.

d. Canadian Association of Petroleum Producers

The Canadian Association of Petroleum Producers (CAPP) supports the continued use of the basic framework of the Gas Accord structure. CAPP contends that the structure of unbundled backbone transmission services offer a flexible, market-responsive form of service for those seeking to bring gas supplies into PG&E's service territory to consume or sell. The unbundled services makes it possible to acquire, sell, and trade firm backbone transportation rights to capacity, which has created a variety of gas supply alternatives that did not exist before the Gas Accord.

CAPP points out that some deficiencies remain with the current Gas Accord structure. Most notable is the use of a rate design that uses a system-wide average load factor to derive rates. As a result, significant cross-subsidies among the transportation paths exist, which artificially favors one gas supply source over another. The continuation of such a rate design may distort price signals, which could increase gas costs in California. CAPP's rate design proposal is discussed later in this decision.

e. City of Palo Alto

PG&E has stated that simply extending current rates through 2004 will deprive PG&E of an opportunity to recover its costs, and such an extension is unlawful. Palo Alto argues that the Commission should not be misled by PG&E. Palo Alto contends that if the costs associated with the issues that were not identified in the scoping memo, or that were not supported by the record in this proceeding, are excluded from the revenue requirement, the revenues at present rates would be sufficient to cover the 2004 revenue requirement without any rate increase. Palo Alto contends that this should not be surprising because PG&E's original application was to extend the Gas Accord through 2004. Palo Alto asserts that PG&E would not have made such a proposal if it did not believe that the revenues would be sufficient to cover its cost of service and authorized return.

f. Department of General Services

The Department of General Services of the State of California (DGS) operates a natural gas services procurement program for the benefit of state agencies and local agencies.[8] DGS agrees with ORA, TURN and others that given the timing and issues in this proceeding, the Commission should simply extend the existing Gas Accord Settlement Agreement through 2004. Although DGS advocated early on in this proceeding that the prudence of the Gas Accord and PG&E's cost of service should be examined, that hasn't occurred due to ORA's staffing constraints. As a result, there has been no comprehensive analysis of the impact that a backbone level rate or PG&E's tiered local transmission rate structure will have on end-users. Due to the limited review of PG&E's proposals, and the particular interests of each party who provided testimony regarding the proposals, DGS recommends that the Commission extend the terms of the Gas Accord through 2004, and order PG&E to file a test year 2005 rate case.

g. Duke

Duke Energy North America and Duke Energy Trading and Marketing (collectively, "Duke") support the continuation of the Gas Accord structure, provided that there is an opportunity for periodic revision. Duke states that the Gas Accord structure has led to increased customer choice through the unbundling of transmission, storage, and balancing services. The Gas Accord

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[8] At the present time, this program provides gas service to 142 noncore customers using an estimated 17.3 Bcf of gas on an annual basis. In PG&E's service territory, the DGS program serves 93 noncore customers who use approximately 11 Bcf of gas. DGS initially acquired firm backbone capacity in PG&E's service territory in the Gas Accord. In the most recently concluded open season, DGS reduced its holdings for 2003 by about one-half, but plans to hold capacity on the Redwood Path in the future.

also led to the establishment of path-specific transmission capacity, which eliminated the problem of overnominations that existed before the Gas Accord was implemented. The Gas Accord has also increased certainty for customers, and increased the value of transportation rights on interstate pipelines. The Gas Accord has also led to the development of a liquid, secondary market at the citygate. Duke contends that all of these benefits justify the continuation of the Gas Accord structure.

h. Indicated Producers

The Indicated Producers is an ad hoc coalition comprised of BP Energy Company, Chevron U.S.A. Inc., and Occidental Oil and Gas. The Indicated Producers support PG&E's proposal to extend the Gas Accord structure because they believe the structure has functioned well over the past five years to the benefit of the utility and its core and noncore customers.

i. Lodi Gas Storage, L.L.C.

Lodi Gas Storage, L.L.C. (LGS) generally supports the Gas Accord structure, and the market competition that it has resulted in. However, as LGS reviewed the testimony in this proceeding, LGS believes that the Commission should simply extend the existing Gas Accord structure for 2004. By the end of 2004, the jurisdictional questions raised by PG&E's plan of reorganization should be resolved. At that point in time, LGS asserts that a full-scale proceeding would make sense.

LGS points out that PG&E's proposals have implications which extend far beyond the end of 2004. Such changes include reconfiguring the assignment of storage capacity, instituting a bypass charge despite the fact that there is no proof that bypass currently exists, and the creation of new winter reliability standards.

These proposed changes, which have long-term implications, should not be adopted in a one-year proceeding.

If, however, the Commission chooses to consider the various proposals raised by PG&E and others, LGS recommends that the Commission adopt the recommendations of LGS as set forth in the sections discussing the various proposals.

j. Mirant

Mirant Americas, Inc. (Mirant) operates three electric generating plants in the San Francisco bay area, which produce 3000 megawatts (MW) of electricity. According to Mirant, it is one of PG&E's largest purchasers of natural gas transmission service.

Mirant contends that this proceeding was an inadequate forum for a detailed analysis of the numerous and complex issues that must be addressed and resolved in order to arrive at a fair and reasonable revenue requirement for PG&E. This proceeding essentially amounted to a general rate case (GRC) for PG&E's gas transmission and storage services.

k. Northern California Generation Coalition

The Northern California Generation Coalition (NCGC) supports the continuation of the basic Gas Accord structure because it will promote regulatory and market certainty. In addition, the structure provides NCGC's members with the opportunity to purchase a mix of services consistent with their individual supply needs.

Although NCGC supports the continuation of the basic Gas Accord structure, changes and refinements should be implemented as market conditions and customer needs change. Such changes, however, should be well explained, well understood, well transitioned, and supported by the customers. Although

PG&E has proposed a variety of changes to the Gas Accord structure and rates, NCGC contends that PG&E has not adequately explained its changes, has not provided sufficient evidence to support the changes, and that the proposed changes are not consistent with customer needs.

I. Office or Ratepayer Advocates

ORA points out that this proceeding originally began with PG&E seeking to extend the existing Gas Accord structure for two years, *i.e.*, until the end of 2004. ORA asserts that the September 30, 2002 scoping memo stated that 2004 should be the focus of this proceeding. ORA contends that in PG&E's amended application, PG&E deviated substantially from the scoping memo by proposing to extend the Gas Accord on a multi-year basis with significant modifications to the current rate and structure.

ORA contends that many of PG&E's proposals are outside the scope of this proceeding, and have significant rate implications which cannot be adequately explored by ORA within the limited time frame of this proceeding. ORA recommends that the Commission adopt PG&E's original proposal to extend the Gas Accord through 2004.

For periods beyond 2004, ORA recommends that the remainder of the issues raised by PG&E in its amended application be addressed in a test year 2005 rate case that PG&E should be ordered to file. Since PG&E's proposals are likely to result in significantly higher core customer rates, sufficient time should be allowed so that the parties can prepare a comprehensive analysis of the issues.

Contrary to PG&E's suggestion in its opening brief at page 4 that ORA "decided to allocate minimal resources to this proceeding," ORA contends that PG&E's statement is incorrect. ORA asserts it was not able to fully participate in this proceeding because of the narrow window of time between the time PG&E's

workpapers became available (during the first week of February 2003) and the date ORA's testimony was due (February 28, 2003). Even if ORA had allocated sufficient resources to this proceeding, ORA could not be expected to prepare a credible analysis of PG&E's voluminous submissions in the time allotted. Even PG&E's witness acknowledged that if PG&E were ordered to file a rate case for test year 2005, it would take PG&E several months to prepare its application and supporting testimony. In order for ORA to adequately review and analyze PG&E's various Gas Accord structure and rate proposals, it should be given a similar amount of time.

ORA also contends that the mere fact that PG&E has requested major rate changes, does not mean that the Commission should consider it. The ability of all parties, including Commission staff, to review a rate request is a relevant consideration in deciding whether to adopt a utility's request. In addition, ORA has identified several of PG&E's proposals as being unjustified and unnecessary. All of those factors provide compelling reasons why PG&E's proposals should be rejected.

ORA contends that PG&E's extensive rate proposals have the effect of substantially increasing core rates, while reducing the rates of noncore customers. ORA asserts there is no justification for the proposed changes, and it is inherently unfair that the rate of core customers will increase while noncore customers will realize a substantial drop in rates. Since ORA and TURN have not had the opportunity to adequately analyze the issues, including the full impact of the proposed rate changes on core customers, ratepayers have been denied the opportunity to effectively participate in this proceeding. ORA also notes that PG&E did not originally seek rate relief in this proceeding, and instead simply sought to extend the current rate structure for an additional two years.

ORA disagrees with PG&E's statement in its opening brief that its various proposals are just "adjustments to improve the reliability of PG&E's system under the Gas Accord structure, not changes to the fundamental structure." ORA asserts that this statement grossly understates the impact on core customers, who will be adversely impacted by the various rate and market structure proposals of PG&E. Much of what PG&E claims to be adjustments to existing Gas Accord structure shifts costs such that large noncore customers would see their rates decrease while, at the same time, the core class would experience a substantial rate hike without any corresponding benefits. ORA asserts that given the substantial impact that PG&E's proposed changes would have, they should be reviewed in a more comprehensive proceeding with sufficient time allotted to all parties to effectively participate.

m. The Utility Reform Network

TURN recommends that the Commission adopt a one-year extension of the current Gas Accord rates and structure, and that PG&E be ordered to file a new gas structure rate case once a plan of reorganization has been confirmed by the Bankruptcy Court.

TURN contends that the issues raised by PG&E have not been adequately reviewed in this proceeding. This proceeding was designed to address a one-year plan, in which intervenor testimony was served only six weeks after the company's primary showing. In addition, the uncertainty regarding the long-term jurisdiction of PG&E's gas assets makes a long-term commitment to a particular market structure unwise. TURN believes that it makes more sense for the Commission to take up the future of the PG&E gas system in a full-blown proceeding after a final plan of reorganization has been confirmed by the Bankruptcy Court.

TURN contends that PG&E has the burden of proof to show by clear and convincing evidence that PG&E's proposed cost of service for its backbone and local transmission and gas storage system are reasonable, and that the rates it is requesting are just and reasonable. TURN asserts that PG&E has not met its burden. TURN asserts that a conclusive, substantive determination of PG&E's cost of service and rates is almost impossible to make because ORA was unable to conduct a review of PG&E's proposed cost proposals.

TURN also points out that much of the increase in the revenue requirement has been contested, which raises substantial doubt about the validity of PG&E's proposals. The proposals which have been challenged include: the need for capital upgrades due to PG&E's proposed Winter Reliability Standard; the cost recovery for the Gerber compressor station fire; the validity of capitalizing non-cycle working gas; and the validity of expensing certain computer and levee reconstruction costs. TURN contends that these items represent a significant portion of PG&E's requested increase in the revenue requirement.

If the Commission chooses to address PG&E's proposals, TURN believes that the Commission should still find that several of PG&E's proposals, including the Winter Reliability Standard and the indefinite continuation of an unbundled structure, go beyond the scope of this proceeding, and should not be adopted based on the record. In addition, rates should only be authorized for one more year, or until a plan of reorganization is accepted by the Bankruptcy Court.

TURN states that it has not expended the time and resources to fully examine the impacts of the unbundled backbone and storage structure on the operation of the gas market in Northern California. However, since the "price benefits" of the Gas Accord citygate market was a major factor in the

Commission's decision to adopt an unbundled structure for SoCalGas in D.01-12-018, TURN performed a limited evaluation of the claimed citygate "benefits."

TURN asserts that its evaluation shows that, on average over the Gas Accord period through June 2002, it was more expensive to buy at the citygate than to buy at the border and flow gas using firm capacity rights. This is shown in Exhibit 13 of PG&E witness Wilson's testimony, which provides a comparison between border-specific intrastate basis differentials and firm capacity costs including shrinkage. According to TURN, Exhibit 13 demonstrates that on average, it was more expensive to buy at the citygate than to hold firm Redwood capacity and buy at Malin. The basis differential exceeded the costs of firm Redwood capacity and shrinkage by 12.6 cents. Exhibit 13 also indicates that on average, it was slightly cheaper to buy at the citygate, than to hold firm Baja capacity and buy at Topock.

TURN contends that given that the Redwood path has a receipt capacity more than one-and-a half times that of the Baja path, and that the Redwood path was flowing at higher load factors during the entire time period between July 1998 and June 2002, on a weighted average basis it was cheaper to hold firm capacity and buy at the border than to buy at the citygate during the original Gas Accord period. The Commission should find that the unbundled market structure has not resulted in a citygate market that provides any price benefits to consumers.

The proponents of continuing the gas structure contend that it was the availability of firm capacity rights that caused prices for Southwest gas moving into PG&E's system (PG&E-Topock) to be considerably lower than for Southwest gas flowing into SoCalGas' system (SoCalGas-Topock). The premise of the argument is that the SoCalGas system was more constrained (meaning that the pipeline was flowing at a higher load factor, with less slack capacity), and that it was the difference in load factors that resulted in higher prices into the SoCalGas system. TURN asserts, however, that when this argument is examined in detail, no link has been established between the supposed cause of lower prices and the existence of unbundled backbone capacity rights. Nor have the differences in load factors between PG&E and SoCalGas been linked to unbundled backbone rights. TURN points out that both utilities expanded their capacities in 2001-2002, and both had a relatively fixed amount of capacity for awhile. TURN asserts that the factual data shows that at best, the Gas Accord provided some benefits during the crisis year, but on average, the city gate prices have exceeded the cost of border plus transportation.

TURN also asserts that the Gas Accord market structure had nothing to do with determining the need for, timing or amount of the capacity expansions that took place over the last two years. Instead, TURN contends that it was due to the dramatic increase in the value of gas services, combined with regulatory pressure by California state regulators which encouraged these projects.

TURN urges the Commission not to reach any long-term conclusions regarding the efficacy or desirability of continuing this unbundled structure into 2005. TURN suggests that the goal of ensuring short-term market certainty regarding transportation rights, balanced with the goal of minimizing unnecessary analysis and evaluation until the outcome of the bankruptcy process is resolved, is best accomplished by continuing the Gas Accord market structure for 2004 only.

C. Discussion

PG&E's backbone transmission, local transmission, and underground storage facilities are described in Chapter 2 of Exhibit 1. These PG&E facilities are currently operated under the rules set forth in the Gas Accord Settlement Agreement, found in Appendix B of D.97-08-055 (73 CPUC2d at 797-855), the Operational Flow Order (OFO)[9] protocols set forth in D.00-02-050,[10] the Comprehensive Gas OII Settlement Agreement in D.00-05-049,[11] and the 2003 extension in D.02-08-070.

The first issue to address is whether the current Gas Accord structure and rates should be extended for 2004. The resolution of the first issue depends on how we address the arguments that the proposals of PG&E go beyond the issues identified in the scoping memo, that ORA and others were unable to devote resources to comprehensively review PG&E's application, and that the parties

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9 An OFO is called on PG&E's gas transmission system when there is an intolerable imbalance between the gas received on the system and the gas delivered from the system. (D.00-02-050, p. 1, fn. 1.)

10 The OFO Settlement Agreement adopted in D.00-02-050 revised PG&E's operating guidelines and gas tariffs relating to OFOs. The OFO Settlement Agreement states in part: "This Agreement does not change the basic principles and structure of the Gas Accord as agreed to by the settling parties to the Gas Accord and as approved by the Commission in Decision 97-08-055. The operating guideline and gas tariff changes included within this Agreement, and made a part hereof, are intended to modify certain limited implementation parameters of the Gas Accord, and the Settlement Parties agree that such revisions are within the original bounds of the Gas Accord structure." (D.00-02-050, Attachment 1, p. 2.)

11 The Comprehensive Gas OII Settlement Agreement addressed a number of issues that were raised in Investigation (I.) 99-07-003. Among the settled issues which impact the Gas Accord are the "Self-Balancing option," electronic trading of imbalances, the unbundling of storage costs for Core Transportation Agents (CTAs), and billing credits for CTAs who provide consolidated billing to gas customers. (D.00-05-049, pp. 18-19; Attachment A, pp. 4-18.)

had insufficient time to fully participate in this proceeding given the issues raised in PG&E's application.

The scoping memo was issued at the time PG&E was requesting a two-year extension of the Gas Accord structure and rates. Thus, the scoping memo identified the ultimate issue as whether the Gas Accord structure and rates should be extended for 2003 and 2004. As a result of the adoption of the Gas Accord II Settlement Agreement in D.02-08-070, the September 30, 2002 ALJ ruling stated that "the focus of this proceeding is only on what the gas structure for 2004 should look like, and whether the existing Gas Accord structure should be continued in 2004." (ALJ Ruling, Sept. 30, 2002, p. 7.) However, the ruling also stated that the cost of service study that PG&E was to provide, and the issues identified in the scoping memo about "how the existing Gas Accord structure has performed, and whether it is in the best interest of the state to continue this kind of structure," provide "the Commission with the flexibility to review PG&E's gas structure on a multi-year basis, rather than just a one year view of what the gas structure should look like in 2004." (ALJ Ruling, Sept. 30, 2002, pp. 7-8.) As we stated in D.02-08-070 at page 18, the hearings in this proceeding "will address the viability of the Gas Accord structure."

Based on the rulings and our statement in D.02-08-070, we are not persuaded by the parties' arguments that the proposals of PG&E go beyond the issues identified in the scoping memo. Since the Gas Accord structure and rates, as extended by D.02-08-070, are to expire at the end of 2003, PG&E's application had to address the kind of market structure that should be adopted for 2004, and what rates should look like. In addition, we solicited testimony from the parties about the performance of the Gas Accord structure, and whether it was in the state's best interest to continue this kind of market structure. PG&E and other parties have provided evidence on these topics.

As for the arguments that ORA did not have the resources and time to do a comprehensive review of PG&E's application, or that parties had insufficient time to address the multitude of issues, we have considered those arguments in our analysis of the various proposals of the parties, as discussed in the sections which follow. In addition, the argument that the cost impacts of the various proposals have not been thoroughly analyzed, have also been considered in our analysis of the various proposals.

We agree with Mirant's statement that PG&E's application and the supporting testimony essentially amounted to a GRC for PG&E's gas transmission and storage system. However, since the Gas Accord structure expires at the end of 2003, and the parties did not mutually agree to settle on the kind of structure and rates that should be in place for 2004 and beyond, there was no alternative but to review all of the proposals of the parties in order to determine what kind of market structure and rates should apply to PG&E's gas transmission and storage system for 2004.

No one has proposed a different market structure for PG&E's gas transmission and storage system. Instead, all of the parties use the existing Gas Accord structure as the basis of their market structure. The proposals of each of the parties would change discrete elements of the Gas Accord structure, which could result in cost impacts. However, the basic foundation of the Gas Accord structure remains unchanged.

We will not adopt the recommendation to simply extend the current Gas Accord structure and current rates for 2004. However, we do adopt the Gas Accord market structure that was developed in the Gas Accord Settlement

Agreement contained in D.97-08-055, as changed by D.00-02-050 and D.00-05-049, and as extended by D.02-08-070, and as changed by the specific proposals adopted by us in today's decision, as discussed in the various sections which follow. As a result of the adopted proposals, and the cost of service presented to us in this proceeding, we adopt rates for 2004 that differ from the 2003 rates.

The second issue pertaining to the market structure, is whether the structure we adopt for 2004 should continue beyond 2004. In order to address this issue, we must consider two factors. The first factor is that some parties suggest that the market structure be adopted for 2004 only. Another factor is how the gas structure has performed, and whether it is in the best interest of the state to continue the structure beyond 2004.

TURN is the primary proponent of not extending the gas structure beyond 2004. TURN's first reason in support of not extending the structure is that the Bankruptcy Court is likely to resolve the jurisdictional issue regarding PG&E's gas assets in early 2004. Although this is likely to occur, we believe there is a need to provide participants in the California gas market with more certainty about what kind of structure will be in place if the Commission retains jurisdiction, and to reduce the regulatory burden on the parties who participate in our proceedings.

If we continue the gas market structure beyond 2004, and the jurisdictional issue is resolved in favor of this Commission, we will have a gas structure in place for 2005. This will eliminate the need for a comprehensive application which addresses what kind of market structure should apply in 2005.

If we choose today not to continue the market structure beyond 2004, that will result in the filing of a comprehensive application to determine the market structure and rates that should apply in 2005, assuming the Commission retains jurisdiction over PG&E's transmission assets. That is, in a few short months, we would be faced again with a similar filing to resolve the same kinds of issues that we resolve today, for 2005.

Given the comprehensive review undertaken in this proceeding, and the evidence in this proceeding about the performance of the Gas Accord structure, we do not believe another comprehensive filing for 2005 would be a wise use of resources. In addition, extending the gas structure beyond 2004 will provide market participants with some certainty about what kind of structure will be in place in the event the Commission retains jurisdiction. In D.00-05-049 at pages 26 to 27, we stated the reasons why certain parties supported the Comprehensive Gas OII Settlement Agreement, including the statement that "Gas market participants have an interest in certainty and stability of rates and terms and conditions of service." If we extend the gas structure beyond 2004 in this decision, this will reduce the burden of having to relitigate the same issues within the span of one year, and provide the parties with an idea of what the gas structure will look like beyond 2004. Should the Bankruptcy Court decide to place PG&E's gas assets under the jurisdiction of the FERC, the gas structure issue will become moot.

TURN's second reason for not extending the gas structure beyond 2004 is because the cost impacts of certain proposals on future years have not been fully analyzed. That is, if certain proposals are adopted for 2004, the costs of such proposals could carry over to future years. As mentioned earlier, we have considered the cost issue in the sections which follow.

PG&E and some of the other parties presented evidence regarding how the Gas Accord structure has performed since its inception, including during the energy crisis period. This evidence is relevant in deciding what kind of gas structure should be in place beyond 2004 because the same kind of Gas Accord structure is being adopted for use in 2004. That is, the past performance of the Gas Accord structure provides relevant information about how the structure is likely to perform in the future if the same or similar kind of structure remains in place.

The evidence shows that the Gas Accord structure has resulted in many gas procurement options and strategies for core and noncore customers, and for gas marketers. Market participants can arrange to purchase gas supplies at the gas basins, and have their supplies transported over interstate and intrastate pipelines to the citygate or to the end-user. Or they can choose to purchase supplies at the border, and have the supplies delivered over the intrastate system, or they can choose to purchase their gas supplies at the citygate. The unbundled, firm tradable capacity rights has created a secondary market which allows market participants to sell or trade their rights to maximize their gas procurement strategies.

Although TURN contends that the data shows that citygate purchases are often more expensive than buying at the border and using firm transportation, no one disagrees that the Gas Accord structure has brought many other benefits to market participants in PG&E's service territory. ORA's own testimony states that "The current Gas Accord has proven to be workable and has provided substantial benefits to customers in the form of increased choice and lower city-gate prices." (Ex. 74, p. 3; PG&E Opening Brief, p. 7.)

The Gas Accord structure has also been the subject of some review by the settling parties in D.00-02-050 and D.00-05-049. In the OFO Settlement Agreement adopted in D.00-02-050, the agreement states in part:

> "Experience under the Gas Accord has indicated that certain adjustments are appropriate, particularly with regard to customer balancing requirements and charges; to issuance of OFOs; to whether OFOs are issued on a system-wide or customer-specific basis; and to the operational information provided to the market and to individual shippers.
>
> …
>
> "This Agreement does not change the basic principles and structure of the Gas Accord as agreed to by the settling parties to the Gas Accord and as approved by the Commission in Decision 97-08-055. The operating guideline and gas tariff changes included within this Agreement, and made a part hereof, are intended to modify certain limited implementation parameters of the Gas Accord, and the Settlement Parties agree that such revisions are within the original bounds of the Gas Accord structure." (D.00-02-050, Attachment 1, pp. 1-2.)

When the settling parties reviewed the promising options for the continued restructuring of the California gas industry that were set forth in D.99-07-015, and settled the issues in the Comprehensive Gas OII Settlement Agreement, the Gas Accord was considered by the settling parties. (D.00-05-049, pp. 6-7, 18-19; Attachment A, p. 1.)

In addition, in our decision regarding the gas structure for SoCalGas and San Diego Gas & Electric Company (SDG&E), we stated that the Comprehensive Settlement adopted in D.01-12-018, "closely follows the structure of the PG&E Gas Accord, which, by all indications, has been working very well even under the extreme market conditions that presented themselves last year." (D.01-12-018, p. 9.)

Based on the evidence presented regarding the performance of the Gas Accord structure, and the structure that we adopt today for 2004, which is virtually identical to the Gas Accord structure that was previously adopted and extended, the same structure that we adopt for 2005.

The rates for 2005 for PG&E's transmission and storage system shall be the subject of a PG&E application to be filed in the first quarter of 2004. We will also consider in that rate application whether minor changes to the gas structure are needed in order to improve the functioning of the gas structure in 2005.

In the event PG&E's gas transmission assets remain under our jurisdiction in 2004, PG&E shall file a comprehensive application no later than February 4, 2005, proposing the kind of market structure and rates that PG&E's gas transmission and storage system should operate under beginning January 1, 2006, and how long the rates and such a structure should remain in place. At that time, parties can raise the same proposals that we have analyzed in today's decision, but which we do not adopt, or they can propose other structural changes to the gas market structure for 2006 and beyond.

IV. Winter Reliability Standard and Winter Firm Capacity Requirement

A. Introduction

This section addresses PG&E's proposal for a Winter Reliability Standard of a 1-in-10 year cold temperature event for its local transmission and central backbone facilities, and PG&E's proposal for a Winter Firm Capacity Requirement which establishes the level of firm capacity commitments to be made by Core Procurement Groups (CPGs)[12] on behalf of core customers.

According to PG&E, these proposals have been raised because the reliability of PG&E's local transmission system, and the potential for supply curtailments, is of concern to noncore customers, especially gas-fired electric

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[12] CPGs include PG&E's Core Procurement Department and gas energy service providers (gas ESPs) serving core cusotmers.

generation customers. If noncore customers are curtailed, it is likely that some electric generation customers will be forced to cease generating electricity, which is likely to result in service interruptions and higher costs for core electric customers.

1. Winter Reliability Standard Proposal

PG&E proposes that the Commission adopt a Winter Reliability Standard which would maintain service to all customers during a 1-in-10 year cold temperature event. If this standard is adopted, PG&E would design its central backbone and local transmission facilities to meet the more stringent of (a) core-only demand under Abnormal Peak Day (APD) conditions, or (b) core plus noncore demand under a 1-in-10 year cold temperature event.

PG&E states that the proposed Winter Reliability for PG&E's system is consistent with the 1-in-10 year cold temperature event standard that was adopted in D.02-11-073 for noncore customers for both SoCalGas and SDG&E.

PG&E's current standard is to design its central backbone and local transmission facilities to meet the more stringent of (a) core-only demand under APD conditions, which is a 1-in-90 year cold temperature event, or (b) to serve 75% of core's APD demand plus all the noncore demand, which is about a 1-in-3 year cold temperature event. Adoption of the 1-in-10 year standard will require reinforcement of PG&E's local transmission system, which is explained more fully below. PG&E's current central backbone facilities and backbone capacity are expected to be sufficient to meet the recommended 1-in-10 year Winter Reliability Standard for the next few years.

If the Commission adopts this stricter Winter Reliability Standard, PG&E proposes that this standard be applied on an ongoing basis beyond 2004. The adoption of an ongoing standard will allow the market to have a greater degree of certainty about the future capability of PG&E's system, and the probability of capacity curtailments. Also, PG&E will be able to identify the facilities needed to support this standard, and to include the costs of these facilities in future applications.

2. Facility Requirements to Support the Winter Reliability Standard

a. Central Backbone Improvements

PG&E's proposal to adopt a 1-in-10 year Winter Reliability Standard is not expected to require a reinforcement or expansion of the central backbone system over the next few years. However, as demand grows in specific geographic areas, and as storage withdrawal from all Northern California storage fields is increased, expansion of these facilities will likely be needed in the future. PG&E plans to monitor the central backbone system's ability to meet a 1-in-10 year reliability standard and propose system reinforcements as needed.

b. Local Transmission Improvements

If PG&E's proposed 1-in-10 year Winter Reliability Standard is adopted, improvements to PG&E's local transmission facilities will be needed to ensure delivery of gas to transmission-level end-use customers and to PG&E's distribution facilities under these cold temperature demand conditions. PG&E estimates that the additional capital cost for this work is about $42 million[13] for 2004-2007. For 2004, PG&E forecasts $2 million in capital expenditures to embark on the improvement of local transmission to meet the Winter Reliability Standard. If PG&E's Winter Reliability Standard proposal is adopted, PG&E

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[13] PG&E notes that the $42 million is an estimate of the capital costs based on what PG&E knows today. If new power plants are built in constrained areas of local transmission, the estimate could change significantly.

states that this "would be authorizing PG&E to begin a four-year reliability improvement program to its local transmission system…." (Ex. 3, p. 4-6.)

c. Backbone Transmission

The capacity of the backbone is generally determined by annual and seasonal needs. PG&E notes that a reserve margin or slack capacity guideline would be more appropriate than a winter reliability criteria for determining the required amount of backbone capacity to meet the annual and seasonal needs of PG&E's customers, and to help moderate commodity prices under a range of future conditions, including dry years. The Commission, however, has declined in D.90-02-016 and D.02-11-073 to adopt a specific reserve margin or slack capacity requirement. In D.02-11-073, the Commission noted that thoughtful system planning of utility systems was still needed.

Because system planning is still needed, PG&E proposes to continue to evaluate the capacity of the backbone receipt point and delivery capacity relative to forecast demand under various scenarios, including dry years. If PG&E identifies scenarios that could lead to extended periods of high utilization of its backbone system in the future, and the market does not appear to be responding, PG&E plans to work closely with the Commission to identify appropriate actions to avoid sustained high commodity prices due to intrastate capacity constraints on the PG&E backbone transmission system.

d. PG&E Storage

PG&E's proposal to adopt a 1-in-10 year Winter Reliability Standard does not directly impact PG&E's storage because PG&E's storage is based on the supply needs of its customers. However, since PG&E's storage fields provide a significant percentage of core's gas supply during a cold temperature event, PG&E's Core Procurement Department will need its current Gas Accord assignment of PG&E's gas storage, plus an additional assignment of 75 MDth/d of withdrawal capacity to meet its Winter Firm Capacity Requirement.

Since the additional 75 MDth/d assignment of storage withdrawal can be met with PG&E's existing storage capacity. PG&E does not expect its customers to request an expansion of storage for 2004. Beyond 2004, as core peak demand grows, PG&E's Core Procurement Department may need to contract for additional gas supplies to meet the Winter Firm Capacity Requirement, which could trigger an expansion of PG&E's storage.

3. Core Winter Firm Capacity Requirement

PG&E proposes a Winter Firm Capacity Requirement for CPGs that determines the level of winter firm transportation and storage capacity commitments that CPGs must hold. PG&E proposes that the Winter Firm Capacity Requirement be set at the level needed to meet core demand for a minimum 1-in-10 year cold temperature event, which is consistent with the Winter Reliability Standard.

For the winter of 2004-2005, PG&E proposes a total core Winter Firm Capacity Requirement of 2,425 MDth per day through January 15, and 2,225 MDth per day through February 15. This calculation is based on the estimated core demand during a 1-in-10 year cold temperature event of 35 degree Fahrenheit.

Under the Gas Accord, the assignment of firm storage and transmission capacity to the core is enough capacity to meet core demand for about a 1-in-3 year cold temperature event. PG&E contends that the stricter Winter Firm Capacity Requirement will provide benefits to core customers, and is needed to capture the full benefits of improved delivery reliability for the noncore that the proposed Winter Reliability Standard would provide. That is, the more gas that core has access to, the less likely noncore supplies will have to be disrupted.

PG&E proposes that the Winter Firm Capacity Requirement for core firm storage and transmission capacity holdings by CPGs reflect expected weather patterns through the winter. From December 1 through January 15, the expected 1-in-10 year temperature is approximately 35 degrees Farenheit. After January 15, the expected 1-in-10 year temperature increases to approximately 38 degrees Fahrenheit. After February 15, the expected 1-in-10 year temperature increases to 43 degrees Fahrenheit. PG&E proposes that CPGs be required to hold enough firm capacity to meet their forecasted core load at the January 15 and February 15 temperature points, *i.e.*, a 35 degree Fahrenheit forecast demand from December 1 through January 15, and a 38 degree Fahrenheit forecast demand from that point through February 15. After February 15, there would be no restrictions or requirements.

In order to meet the Winter Firm Capacity requirement, CPGs will need an additional assignment of 75 MDth/d of firm storage withdrawal above their current firm capacity holdings. The PG&E Procurement Policy section addresses the firm capacity holdings recommended for CPGs to meet the proposed requirement.

The Winter Firm Capacity Requirement would require CPGs to have gas supplies available, which reduces the need for CPGs to buy gas at the citygate during cold temperature events. By reducing core demand for immediate gas supplies during cold temperature events, the Winter Firm Capacity Requirement should help core to reduce its expected gas costs during cold temperature events, and help moderate gas prices at the citygate to the benefit of all customers.

PG&E also notes that the Winter Firm Capacity Requirement also benefits core gas customers by reducing potential EFO noncompliance charges that would be incurred if supply is not available during a cold temperature event, and the system must curtail noncore customers to free up gas supply for service to core customers.

B. Other Proposals

If the Winter Reliability Standard is adopted, TURN suggests that the Commission consider moving from a cold year peak month allocator to a cold year non-coincident peak month measure to allocate local transmission costs.

LGS proposes that if PG&E's proposed Winter Firm Capacity Requirement is adopted, the Commission should require PG&E's Core Procurement Department to put the 75 MDth/d of withdrawal capacity out for bid, rather than allowing PG&E's at risk storage department to provide such service to the core.

C. Positions of Parties

1. Lodi Gas Storage

LGS does not oppose the concept of a 1-in-10 year winter reliability standard, but is concerned that PG&E seeks such a standard with little evidentiary support, and then seeks to implement it in a fashion which is anti-competitive. LGS also points out that PG&E's proposals, such as reconfiguring the assignment of storage capacity and the creation of the Winter Reliability Standard has implications which extend far beyond the end of 2004, and should not be adopted in a one-year proceeding.

LGS contends that PG&E be required to support its reliability proposal before the Commission adopts it. PG&E has not demonstrated that its reliability proposals are needed, and thus has not met its burden of proof. The only thing that PG&E has proven is that PG&E's witness has admitted that the sole support for these proposals is that the Commission adopted a similar standard for SoCalGas and SDG&E. (3 RT 191-192.)

ORA states that the winter reliability proposals require complicated and time-consuming assessment, and that PG&E has presented no concrete evidence that its current standard needs improvement. TURN states that a 1-in-10 standard may ultimately make sense, but that determination should be made in a forum in which there is adequate time and staff resources to perform the necessary analysis. LGS states that PG&E has not performed that analysis. PG&E's rebuttal testimony states that there was no need for a detailed cost-benefit analysis for the standards. LGS asserts that PG&E is simply trying to piggyback on another Commission decision which addresses different utilities with a system that is not the same as PG&E's.

If PG&E demands that studies of its opponents' proposals be provided, then PG&E should also provide such studies of its own proposals, which PG&E has not done for the Winter Reliability Standard. LGS asserts that changes of the magnitude in PG&E's proposals should not be made without presentation of appropriate analysis and supporting evidence by the party proposing the changes.

LGS notes that PG&E's opening brief at page 7 acknowledges that its winter reliability proposals are "not market structure issues, and the Commission can easily decide to accept, reject, or modify PG&E's proposals in these areas within the context of the overall Gas Accord market structure." PG&E also states at page 17 of its opening brief that its winter reliability proposals "are adjustments to improve the operation and reliability of PG&E's system under the Gas Accord structure, <u>not</u> changes to the fundamental structure." If PG&E believes these reliability proposals are important, it should conduct appropriate studies and present them again with better support in a future proceeding to which the proposals are related. When PG&E admits that these two reliability proposals are unrelated to the gas market structure, and when there is a lack of support for such proposals, such proposals should be rejected.

As for the 75 MDth/d of storage needed to support the Winter Firm Capacity Requirement, LGS contends that there were significant inconsistencies regarding the source of this capacity. In its direct testimony, PG&E stated that "PG&E Core Procurement will need its current Gas Accord I assignment of PG&E's gas storage plus an additional assignment of 75 MDth/d of withdrawal capacity to meet its Winter Firm Capacity Requirement as proposed below." (Ex. 1, p. 4-9.) The same testimony goes on to state that the additional withdrawal capacity "can be met with PG&E's existing storage capacity…." (Ex. 1 at 4-9.) LGS believes that the clear implication of this testimony is that the 75 MDth/d of withdrawal capacity assigned to at-risk storage in the original Gas Accord would be reassigned to the core. LGS' opening testimony was based on that assumption. (*See* Ex. 19 at 3.)

After PG&E and the other parties submitted testimony, it became known that PG&E was proposing a wholesale revision of the storage assignments contained in the Gas Accord settlement agreement. Rather than reassigning withdrawal capacity from at-risk storage to the core, PG&E is conducting what amounts to a bottoms-up redesign of the storage system assignments to various users. According to PG&E, the 75 MDth/d is available because PG&E increased withdrawal capacity over the period since adoption of the original Gas Accord, and because of the existence throughout that period of a peaking agreement between PG&E's Core Procurement Department and PG&E's at-risk storage department.

LGS asserts that the assignment of 75 MDth / d to the core, without giving third party storage providers the opportunity to bid for that capacity, is anticompetitive and not in the best interests of captive core customers. LGS is concerned that the proposed Winter Firm Capacity Requirement is just a way for PG&E to market its own storage on a rolled-in basis to captive ratepayers to compete against LGS and Wild Goose Storage Inc. (Wild Goose) in the marketplace.

Should the Commission adopt PG&E's proposed Winter Firm Capacity Requirement, it should require PG&E's Core Procurement Department to put the 75 MDth / d of capacity out for bid. LGS notes that TURN, whose charge is protect core ratepayers, also agrees that such capacity should go out for bid.

2. NCGC

NCGC supports PG&E's proposal for a Winter Reliability Standard, PG&E's proposal for establishing a Winter Firm Capacity Requirement for CPGs, and for expanding the local transmission system. The adoption of the Winter Reliability Standard for PG&E is consistent with the standard established by the Commission for SoCalGas and SDG&E in D.02-11-073.

NCGC points out that in order to meet the proposed Winter Reliability Standard, PG&E will need to reinforce its local transmission system, and PG&E's Core Procurement Department will need to acquire additional withdrawal storage capacity in order to meet the standard. Backbone transmission would not require expansion. PG&E, however, proposes to evaluate the capacity of the backbone system, and to work closely with the Commission to identify appropriate actions to avoid sustained high commodity prices due to intrastate capacity constraints on PG&E's backbone transmission system. NCGC supports PG&E taking on such a role since capacity expansions are less costly than commodity price spikes that can occur if transmission capacity is constrained. The adoption of the Winter Reliability Standard will reduce the costs imposed on noncore customers in the event of a gas curtailment.

TURN suggests that if the Commission adopts the 1-in-10 year standard, that the Commission should consider moving from a cold-year peak month allocator for allocating local transmission costs to a cold year non-coincident peak month measure. NCGC says there is no merit to TURN's proposal. If local transmission facilities are sized to meet demand during a 1-in-10 year cold temperature event, that means the local transmission system is sized to meet coincident demand by all customers during such an event. NCGC says it would be inconsistent to size the local transmission system to meet coincident demand and then adopt a marginal demand measure based upon non-coincident demand.

3. ORA

ORA contends that the assessment of PG&E's Winter Reliability Standard proposal is complicated and time consuming, and that such an assessment has not been done by ORA given the time constraints. ORA notes that PG&E has not presented any concrete evidence that its current standard is in need of improvement. ORA also contends that it took two years to review the Winter Reliability Standard for SoCalGas and SDG&E.

PG&E's proposal for a 1-in-10 year Winter Reliability Standard would replace the less stringent 1-in-3 year winter reliability standard. ORA asserts that the impact of this proposal goes beyond 2004 because PG&E proposes to implement it over a four-year period. The projected cost to upgrade the standard was initially estimated at $34.1 million, but in PG&E's updated testimony, has grown to $42 million. Although PG&E proposes that authorization be granted now, and that the implementation details be examined in the future, ORA contends that adopting the multi-year standard with uncertain costs and uncertain implementation parameters is contrary to the interest of ratepayers who may be subjected to huge rate increases several years down the road when the project is completed.

ORA is opposed to examining the winter reliability issue in this proceeding, but is not opposed to examining this issue in a future comprehensive proceeding. ORA contends that the assessment of winter reliability standards is complicated and time consuming, and requires extensive inquiry into the adequacy of the utility's current standards, an analysis of the need for future improvement, cost studies, and a careful cost allocation methodology. ORA contends that PG&E has not presented concrete evidence that its current standard is in need of improvement, and there was insufficient time in this proceeding to properly evaluate PG&E's proposed Winter Reliability Standard.

ORA also points out that because there is a correlation between PG&E's Winter Reliability Standard and its proposed increased core penalties, if the Commission rejects PG&E's proposed winter reliability standard, the Commission should also avoid considering PG&E's proposed OFO or EFO penalties.

4. Palo Alto

Palo Alto asserts there is no reason to adopt the proposal at the present time since the benefits in 2004 are de minimis.

Palo Alto also asserts that despite appearances, the proposed core firm storage requirement will not result in a 75 MDth/d increase in the physical amount of storage withdrawal capacity actually held by CPGs. PG&E's witness testified that CPGs currently have access to 100,000 Dth per day of additional firm withdrawal capacity under an agreement with the California Gas Transmission (CGT) group. (3 RT 200-201.) To comply with the 1-in-10 year firm storage requirement, CPGs would simply exchange this agreement for an additional 75,000 Dth per day of standard firm storage service. As a result, there would not be a 75,000 Dth per day increase in CPGs' firm rights, as appeared to be the case in PG&E's prepared testimony in Chapter 6 of Exhibit 1.

5. TURN

TURN suggests that PG&E's proposal for a Winter Reliability Standard and Winter Firm Capacity Requirement go beyond the scope of this proceeding as set forth in the February 26, 2002 scoping memo. While a 1-in-10 standard may ultimately make sense, TURN asserts that such a decision should be made in a forum in which there is adequate time and staff resources to perform the necessary analysis. TURN contends that these two proposals require engineering analysis by the Commission's staff, which has not occurred because of the limited time frame of this proceeding.

TURN contends that PG&E's proposal shifts costs away from noncore customers, who will receive more reliable service under the proposal, onto core customers who will pay more for the facilities that will be built to improve service to the noncore.

TURN points out that PG&E already has a more stringent 1-in-90 year cold temperature event standard for serving core demand, and a 1-in-3 year cold temperature event standard for serving noncore customers. Thus, the explicit goal of the new Winter Reliability Standard is to "improve noncore customer and gas-fired electric generation reliability." (Ex. 3, p. 4-1.) In order to meet this standard, PG&E forecasts investing approximately $42 million in local transmission projects between 2004 and 2007.

Although PG&E claims that its proposed standard is consistent with the standard adopted for SoCalGas and SDG&E in D.02-11-073, TURN points out that PG&E's proposal is to maintain service to all customers during a 1-in-10 year cold temperature event. The SoCalGas and SDG&E decision only adopted the 1-in-10 year standard for firm noncore service. TURN states that if $42 million is going to be spent to improve the level of service to noncore customers, those noncore customers should be required to commit to firm service on a multi-year use-or-pay basis. Also, PG&E's proposal would shift costs away from noncore customers, who would be receiving more reliable service, to core customers who would end up paying more for the facilities being built to improve service to the noncore. TURN asserts that the inequities of PG&E's proposal should be more closely examined.

If a higher standard of reliability for noncore service is adopted, TURN recommends that the Commission consider moving from a cold-year peak month allocator to a cold-year non-coincident peak month measure. TURN contends that such a methodology would better capture the impact on the system of those noncore customers whose maximum usage occurs in a month other than January. Since the local transmission system must be "sized to meet the maximum demand of local or specific customers," whenever it occurs, a large noncore customer with a non-January peak load could require the installation of a larger local system, especially if there is not a heavy core load in the area. (*See* Ex. 1 at 14-23; Ex. 77, p. 16.) TURN asserts that PG&E's testimony suggests that even though the planning criterion is based on a cold day, there appears to be a significant possibility that actual planning for local transmission reinforcements will be driven by electric generator demands during non-winter conditions.

LGS suggested that PG&E's Core Procurement Department should not assume that PG&E will be the provider of additional storage needs. TURN agrees that the core should be allowed to shop around like any other gas customer, and that a bidding process may be the best way to meet any increased core storage needs. However, due to the potential conflicts of interest involved, the Commission should oversee any such process to ensure that core customers are not being used to cross-subsidize new utility facilities when cheaper competitive opportunities exist.

6. Wild Goose

PG&E proposes a Winter Firm Capacity Requirement that establishes the level of firm capacity commitments which must be made by CPGs on behalf of core customers. Wild Goose does not oppose the implementation of such a requirement. However, it does oppose the manner in which PG&E proposes that the core meet the new capacity requirement, through an assignment of an additional 75 MDth/d of storage withdrawal from PG&E-owned at-risk storage. Wild Goose contends that PG&E's proposal does not account for the presence of two independent storage providers on its system who should be given the opportunity to compete to provide the additional withdrawal capacity to the core, as well as to the noncore. Wild Goose requests that the Commission clarify that independent storage providers are authorized to compete for provision of service to the core.

7. PG&E

PG&E notes that its proposed Winter Reliability Standard consists of two elements. The first element is the Winter Reliability Standard, which, if adopted, would guide PG&E's design of its backbone and local transmission system to maintain service to all customers during a 1-in-10 year cold temperature event. Adopting the proposal would start the implementation of a four-year program (2004-2007) to upgrade its local transmission system to the more stringent planning standard for service to both core and noncore customers. PG&E will also continue to ensure that its local transmission facilities can serve all core customers during an APD, a 1-in-90 year event.

The second element of the proposed Winter Reliability Standard is that CPGs, including PG&E's Core Procurement Department, will be required to meet the Winter Firm Capacity Requirement. This means that the core will need to obtain sufficient firm transmission and storage capacity to meet their forecasted demand under 1-in-10 year cold temperature condition. To meet this Winter Firm Capacity Requirement, an additional 75 Mdth/d of firm withdrawal capacity needs to be assigned to the core. This requirement will reduce the CPGs' reliance on noncore supply diversion or curtailment, and improve reliability for noncore customers.

PG&E contends that having the Commission adopt the same Winter Reliability Standard as SDG&E and SoCalGas will promote a common level of firm gas transmission service reliability throughout the state. The adoption of the proposed Winter Reliability Standard for 2004 will allow PG&E to properly plan for future facility additions, and for CPGs to make the additional transportation and supply arrangements to meet the higher reliability standard. If the Commission does not adopt the proposed Winter Reliability Standard, or action is delayed, then the facilities and commitments to meet this standard will not be in place should cold winter conditions occur, or it will delay the necessary upgrades to meet the proposed standard.

PG&E asserts that its Winter Reliability Standard proposal is timely and within the scope of this proceeding. If adopted, the Winter Reliability Standard and Winter Firm Capacity Requirement will increase reliability, mitigate gas price spikes, and reduce core noncompliance penalties.

PG&E's proposal to adopt a 1-in-10 year Winter Reliability Standard is not expected to require reinforcement or expansion of the central backbone system over the next few years. However, the proposed Winter Reliability Standard will require improvements to PG&E's local transmission facilities to ensure delivery of gas to transmission-level end-use customers and to its distribution facilities. PG&E estimates that these improvements will cost about $42 million in capital expenditures over the four-year period of 2004 to 2007. Only about $2 million is proposed to be included in 2004 rates. The costs of the improvements beyond 2004 would be included in rates in following years, and subject to review and approval through the Commission's application process. PG&E notes, however, that if the Commission approves the proposed Winter Reliability Standard, the approval would authorize PG&E to begin a four-year reliability improvement program to its local transmission system.

LGS, TURN, Palo Alto and ORA all call for additional analysis of PG&E's Winter Reliability Standard proposal. PG&E asserts that none of them have explained why the SoCalGas / SDG&E decision in D.02-11-073 should not apply to PG&E's service territory. PG&E contends that the Commission has already made a determination in D.02-11-073 of the benefits of a 1-in-10 year design standard. The three main benefits of higher reliability apply to Northern California, as well as to Southern California. These three benefits are: (1) a higher reliability standard reduces service interruptions to the noncore market, and the types of businesses representing the noncore market are the same in the north and the south, and the impacts of curtailment are the same; (2) a higher reliability standard reduces spot gas price increases during periods of high demand; and (3) a higher reliability standard reduces electric generator outages.

Although the Commission spent two years studying the issue for SDG&E and SoCalGas, PG&E asserts that a similar effort is not needed in Northern California. To suggest that further study is needed now, is basically suggesting that the Commission erred in its decision regarding SDG&E and SoCalGas.

LGS also opposes PG&E's winter reliability proposal because PG&E's Core Procurement Department does not propose to bid out the additional 75 Mdth/d of storage withdrawal capacity that it would need to meet the Winter Firm Capacity Requirement. Wild Goose opposes PG&E's proposal that the 75 Mdth/d of additional withdrawal capacity would not be put out to bid. PG&E contends that these objections are misplaced and based on self-interest. PG&E asserts that D.93-02-013 obligates PG&E to provide the storage capacity for core reliability needs. Unless this policy is changed, the core cannot seek bids from third-party storage providers to provide the added storage withdrawal capacity to meet reliability needs. PG&E asserts that since the Commission has not yet unbundled PG&E's obligation to provide core storage, the suggestion that PG&E's proposal is anticompetitive is absurd. If LGS or Wild Goose wants to change Commission policy, then it should develop such a proposal and present it to the Commission.

PG&E points out that its rebuttal testimony demonstrates that the increase in the capital expenditures related to the Winter Reliability Standard was to reflect the increase in the installed unit cost ($/ft) for current pipeline installation costs.

D. Discussion

After reviewing the record in this proceeding, and the arguments of the parties, there are several reasons why PG&E's Winter Reliability Standard and the related Winter Firm Capacity Requirement proposals should not be adopted at this time.

First, PG&E seeks to apply the 1-in-10 year cold standards that were approved for SDG&E and SoCalGas in D.02-11-073 to PG&E's transmission system. However, D.02-11-073 was a proceeding opened by the Commission to specifically investigate the "adequacy of the SoCalGas and SDG&E gas supply and transmission system to provide service to present and future core and noncore customers of SDG&E." (D.02-11-073, p. 3.) Unlike that proceeding, the central focus of this proceeding is to address the gas market structure for PG&E's gas transmission and storage systems, and to set rates for 2004.

PG&E's own witness acknowledged on cross examination that PG&E's proposals for the Winter Reliability Standard and the Winter Firm Capacity Requirement were based solely on the Commission's adoption of the 1-in-10 year reliability standard adopted for SoCalGas and SDG&E in D.02-11-073. (3 RT 191-192.) PG&E provided very little support to justify why a proceeding investigating a specific set of circumstances in Southern California should be applied equally to PG&E.

Our second reason for not adopting the proposals is that the Winter Reliability Standard is a design planning tool that the utility uses to design its transmission system to meet certain design criteria. The planning and design of the size of the transmission facilities to serve customer load, is not, as PG&E acknowledges, a gas market structure issue. Instead, as noted by TURN, it is an engineering issue that requires careful review. ORA was unable to provide that kind of assistance in this proceeding.

The design and planning of the transmission system to address a 1-in-10 year cold temperature event also has numerous ramifications throughout this proceeding. As noted in the matrix of proposals, many of PG&E's other proposals are specifically tied to the Winter Reliability Standard. In order to thoroughly evaluate all of these proposals, we must start with a thorough evaluation of the root proposal. That evaluation cannot hinge solely on a decision which was opened to investigate the ability of the transmission systems of SDG&E and SoCalGas to serve SDG&E's customers. In addition, PG&E has not provided any documentation to support its need to have a stricter design standard. Without a thorough understanding of the need for a stricter standard, we should not allow PG&E's stricter and more costly proposal to go forward and impact other elements of the gas market structure.

We also note that a system-wide diversion of PG&E's noncore customers has never been called. In addition, the current design criteria for PG&E's transmission system is to meet the more stringent of (a) core demand under APD conditions, which is a 1-in-90 year cold temperature event, or (b) 75% of core's APD demand plus all noncore demand, which is about a 1-in-3 year cold temperature event. Although the 1-in-10 year cold temperature event may be a worthy goal and warranted at some point, PG&E has not met its burden of proving in this proceeding that the Winter Reliability Standard is needed at this point in time.

The third reason for not adopting the proposals is there is still uncertainty regarding future regulatory authority over PG&E's transmission system. The Bankruptcy Court has not yet addressed this issue. PG&E states quite clearly in its testimony that if we approve the Winter Reliability Standard proposal, we are authorizing PG&E to begin a four-year process of upgrading its local transmission facilities to meet the 1-in-10 year requirement. Due to the uncertainty of whether we will retain jurisdiction over PG&E's transmission facilities, it does not make sense at this time to commit to a four-year capital expenditure program which may cost $42 million or more.

The fourth reason for not adopting the proposals is that the cost of meeting the Winter Reliability Standard is still uncertain. Although PG&E forecasts that the upgrade of local transmission facilities will cost $42 million over four years, PG&E's witness acknowledged that the amount was "based on a very quick and dirty analysis of the types of expansions that would be needed to meet that standard that you may not need to incur in the absence of that standard." (2 RT 104.) In addition, PG&E's testimony noted if new power plants are located in areas of local transmission constraints, costs could change significantly.

If we approve PG&E's Winter Reliability Standard proposal, we would be embarking on a four-year commitment of upgrades with costs that are subject to further change. Given the high prices for natural gas for the foreseeable future, and expected higher winter heating bills, it is unwise to adopt PG&E's proposals to incur additional costs without adequate justification. In addition, the adoption of PG&E's Winter Reliability Standard proposal would also affect other proposals of PG&E in this proceeding, which have a cumulative effect on the cost of service and on PG&E's overall revenues.

For the reasons stated above, we do not adopt PG&E's proposal for a Winter Reliability Standard for the design and planning of PG&E's transmission system for 2004 and beyond, and we do not adopt PG&E's proposal for a Winter Firm Capacity Requirement. These proposals may be raised again when we review the type of gas structure that should be in place for 2006 and beyond, or in another proceeding where the long-range service aspects of PG&E's gas transmission services are being examined.

Since we do not adopt the Winter Reliability Standard, there is no need to address the proposals of TURN and LGS concerning the peak month allocator, and storage service competition, respectively.

Due to the rejection of PG&E's Winter Reliability Standard and related Winter Firm Capacity Requirement, other PG&E proposals in this proceeding are affected, as well as the associated costs. These other proposals are addressed in the other sections of this decision.

V. Transmission Services

A. Background

This section addresses the rules for contracting for service on PG&E's backbone transmission and local transmission system. It describes the contracting rules that were developed in the Gas Accord, and PG&E's proposals to improve its service offerings. For 2004, PG&E proposes that the basic Gas Accord structure for backbone transmission service be retained, and that enhancements be added to improve the service offerings.

The Gas Accord provides rate certainty for standard rates on a non-discriminatory basis, and the flexibility to negotiate transmission and storage rates. In addition, the Gas Accord created tradable rights for both transmission and storage capacity that can be purchased by any market participant.

Under the Gas Accord, PG&E was authorized to market capacity on its intrastate backbone transmission system under Commission-approved tariffs.

PG&E agreed to be at risk for the revenues, and any profit or loss from the backbone. No balancing account was authorized.

1. Current Structure for Local Transmission Services

For local transmission service, PG&E's end-use customers contract for local transmission service as part of their Natural Gas Service Agreement (NGSA).

PG&E's local transmission charges are non-bypassable for on-system deliveries. Although PG&E allows backbone and local transmission services to be contracted for separately, both services apply to all deliveries to all end-use customers located within PG&E's service territory. This structure obligates all customers that flow gas on PG&E's on-system backbone transmission paths to pay for a share of PG&E's local transmission system.

Direct connects to the backbone to avoid local transmission charges within PG&E's service territory are not allowed. In addition, the rules prohibit allowing gas to flow on another backbone service provider directly into PG&E's local transmission system to avoid PG&E's backbone charges. PG&E proposes to retain these same rules in 2004.

2. Current Structure for Backbone Transmission Services

For gas producers, marketers, and noncore end-use customers, PG&E's backbone transmission service may be contracted for separately from local transmission services through a Gas Transmission Service Agreement (GTSA). For core end-use customers, a GTSA is not required because backbone service is provided to these customers through capacity holdings assigned to their CPG.

Backbone transmission services and rates are differentiated by path and type of service.

a. Paths

The Redwood Path is linked to Canadian and Rocky Mountain supplies. The Baja Path is linked to Southwest and Rocky Mountain supplies, and the Silverado Path is linked to California supplies. The Mission Path provides access to both PG&E and third party storage facilities in Northern California. A PG&E citygate was created at the connection between the backbone system and the local transmission system. The citygate allows direct gas-on-gas competition among supply basins and storage gas within Northern California. During the Gas Accord, the citygate has become a major trading point. PG&E proposes that the citygate be continued.

b. Firm and as Available Rights

Shippers may contract for firm or as-available service on each path of PG&E's backbone transmission system. Firm service guarantees a shipper, in exchange for a monthly demand charge, use of the contracted capacity unless maintenance or some other infrequent event reduces the pipeline's overall capacity.[14] Shippers holding firm service can sell their firm capacity rights to other shippers in the secondary market.

As-available service provides capacity when firm rights are not fully utilized, and is subject to interruption depending on how much pipeline capacity is available. As-available service has a lower priority than firm service, and only has a volumetric charge. As-available service requests are ranked by contract unit price, and are assigned capacity from the highest price on down until all the capacity is fully scheduled.

[14] In the event this occurs, the firm service is rationed on a pro rata basis, regardless of the owner of the contract.

c. Delivery Points

PG&E's on-system service is for ultimate delivery to an on-system end-use customer. On-system delivery points include deliveries to PG&E's local transmission and distribution facilities (PG&E citygate), PG&E's storage facilities, third-party storage facilities located in PG&E's service territory, or end-use or wholesale loads located in PG&E's service territory.

An off-system delivery point is any point of interconnection with an interstate pipeline, third-party pipeline delivering to an off-system customer, or regulated California utility, where the gas being delivered is eventually consumed outside of PG&E's service territory. The off-system designation is specified in a shipper's GTSA. The off-system designation is considered a separate path from the on-system designation, and currently has a separate transportation rate.

d. Standard Service

PG&E provides backbone transmission services under a variety of standard and negotiated rate schedules. Under the Gas Accord, the standard rate schedule is available to all creditworthy entities at fixed rates and at specific terms and conditions to the extent capacity is available. These standard services are also referred to as default or recourse services. If a customer prefers a rate that is different from the standard rate, then service must be provided under tariffs for negotiated services.

When contracting for standard backbone transmission services, a customer may choose the volume (depending on firm capacity availability), the term, and the rate design, either Modified Fixed Variable (MFV) or Straight Fixed Variable (SFV). Any other variations in rates or terms of service must be arranged under the negotiated services.

Under the Gas Accord, the maximum term for standard service was for the five-year term of the Gas Accord, with certain exceptions. PG&E is proposing to allow shippers the option of subscribing for longer terms of up to 15 years for standard service.

e. Negotiated Service

Negotiated services allow a shipper to more closely match its transportation needs, as compared to service under the standard rate schedules. Negotiable rates are available under PG&E's four negotiable backbone transportation tariffs. These four rate schedules are: G-NFT – Negotiated Firm Transportation On-System; G-NFTOFF – Negotiated Firm Transportation Off-System; G-NAA – Negotiated As-Available Transportation On-System; and G-NAAOFF – Negotiated As-Available Transportation Off-System. These tariffs allow for the negotiation of take, term, and price. The "take" refers to variations in the monthly demand charge or "take or pay" requirement. Any other negotiated contract term requires specific Commission approval of the contract.

The Gas Accord also addressed certain terms and conditions of negotiated contracts. PG&E's backbone transportation negotiable tariffs contain a specific provision which ensures that the standard tariff rates and terms are available to all customers in lieu of negotiated rates and terms. The negotiable tariffs also provide that:

> "PG&E may distinguish between parties in offering negotiated rates by evaluating differences in circumstances and conditions, including, but not limited to, differences occurring upstream of, downstream of, or at, the Customer's location, and differences affecting either cost of service to the Customer or the Customer's market alternatives. Negotiations with Customers under this rate schedule will be conducted without undue preference or undue discrimination

to the Customer or to any third party." (*See* 73 CPUC2d at 815; PG&E Schedule G-NFT.)

The Gas Accord and the negotiated tariffs also provide that in exchange for negotiable terms, the maximum negotiated rate authorized in the Gas Accord is 120% of the corresponding standard rate for the same service. The price floor for all negotiated contracts is the short-run marginal cost.

f. Discounting

A negotiated rate under PG&E's negotiable tariff can be described as a discount from the standard rate or as a premium to the standard rate. A premium to the standard rate occurs when a service feature of the standard tariff has been revised for the benefit of the shipper, and the shipper is willing to pay a higher price for that benefit. The premium rate that is paid provides PG&E with an appropriate incentive to change the service feature.

A discount to the standard rate occurs when service is provided at a price below the standard rate. Discounting occurs when PG&E has a financial incentive to do so. For on-system shippers, PG&E discounts the negotiated rate only when the lower rate would provide an end-use customer with an incentive to use more gas than it would absent the discount. For gas flowing off-system, PG&E's negotiated rate for off-system delivery is priced to provide shippers with an incentive to use PG&E's pipelines as opposed to using interstate pipelines. When a discount is offered, PG&E benefits from the additional volume of gas that is transported on the system.

3. Proposals

a. Basic Backbone Transmission Services Structure

For backbone transmission services, PG&E proposes to maintain the same basic structure developed in the Gas Accord for 2004 and beyond. The paths, firm and as-available rights, on-system and off-system service, and standard and negotiable services, all would continue subject to the changes proposed below.

b. Basic Local Transmission Services Structure

For local transmission services, PG&E proposes to continue with the same basic structure developed in the Gas Accord for the years 2004 and beyond. This basic structure obligates all customers that flow gas on PG&E's on-system backbone transmission paths to pay for a share of PG&E's local transmission system. As discussed in the cost allocation section of this decision, PG&E is proposing to segment local transmission rates to better reflect the cost of serving large noncore customers.

c. Long-Term Firm Backbone Contracts

PG&E proposes to allow shippers to contract for firm backbone service for up to 15 years for standard firm service. PG&E proposes that the amount of the firm capacity available for such long-term contracts be limited for the period covered by this proceeding to 400 MDth/d on the Redwood Path, and 200 MDth/d on the Baja Path. This represents about 20% of the available firm capacity. The long-term contracting proposal would not apply to capacity assigned for core customer use.

Under PG&E's proposal, those shippers who request long-term firm capacity contracts must agree to pay the standard firm tariff rate. Thus, the long-term contracts will be subject to future rate changes. These shippers are free to participate in any future rate proceedings.

Each long-term contract would be tied to the terms of PG&E's standard firm tariff and GTSA, and be subject to any future changes by the Commission. PG&E proposes to file any agreement longer than five years with the Commission for informational purposes.

d. Commensurate Discount Rule

When the Gas Accord Settlement Agreement was adopted in D.97-08-055, the Commission added the commensurate discount rule as part of the negotiated rate guidelines. (73 CPUC2d at 784-785.)[15] PG&E proposes to maintain this requirement in 2004, but to adjust the rule to remove certain disincentives PG&E is facing in meeting market needs.

PG&E proposes that the tariff language for the commensurate discount rule be changed to the following:[16]

> "Whenever PG&E offers a rate under this rate schedule which is below the tariff rate cap for Schedule **G-AFT** on its Redwood to On-System path, PG&E shall contemporaneously offer a commensurate discount (*i.e.*, the same penny for penny discount up to the specified quantity and up to the specified term in any discounted contract with any Redwood to On-System shipper) to all **prospective** shippers for firm service from the tariffed rate cap for schedule **G-AFT** for the Baja to On-System and Silverado to On-System paths, to the extent capacity is available **up to an equivalent volume in aggregate to the discount offered for Redwood to On-System service.**" (Ex. 1 at 5-12.)

PG&E proposes that a discount be defined as any on-system offer with a rate below the standard firm (G-AFT) rate for a negotiated firm service contract

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[15] The tariff language for the commensurate discount rule was approved in Resolution G-3288, which provides: "Whenever PG&E offers a rate under this rate schedule which is below the tariff rate cap for Schedule G-NFT on its Redwood to On-System path, PG&E shall contemporaneously offer a commensurate discount (*i.e.*, the same penny for penny discount up to the specified quantity and up to the specified term in any discounted contract with any Redwood to On-System shipper) to all shippers for firm service from the tariffed rate cap for schedule G-NFT for the Baja to On-System and Silverado to On-System paths, to the extent capacity is available." (Schedule G-NFT.)

or below the standard as-available (G-AA) rate for negotiated as-available service contract. PG&E seeks this change because it believes the commensurate discount rule should only apply when a contract's rate is below the standard rate. D.97-08-055 interpreted a discount to be any rate offered below the maximum negotiated rate, which is 120% of the standard tariff rate. PG&E believes such a definition of a discount is too restrictive. The negotiated rate cap was intended to allow PG&E to provide additional upward pricing flexibility in a negotiated contract, to encourage PG&E to provide specific services to customers who were willing to pay more than the standard rate. It is not an appropriate benchmark to use for the purpose of defining what constitutes a discount. The unintended consequence is that there is a disincentive for PG&E to reduce the negotiated contract rate below the maximum.

PG&E also proposes to separately offer the commensurate discount for an aggregate volume equal to the volume of the Redwood discount for both the Baja and Silverado paths. This means that if PG&E offers a one-month discount for 10 MDth/d on the Redwood Path, an equal one-month discount would be offered for 10 MDth/d for Silverado Path service and 10 MDth/d for Baja Path service. Resolution G-3288 requires, however, that a discount to a small volume on a Redwood-on contract be offered to all volumes on the Baja and Silverado paths, which results in a very unbalanced incentive structure. Consequently, PG&E declined to offer any on-system discounts for Redwood capacity, even in circumstances where such a discount on a stand-alone basis might be economic and better serve the market.

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[16] The proposed changes are shown in bold.

e. Scheduling Non-Performance

Scheduling non-performance usually occurs when a shipper submits a large nomination for as-available service at a constrained receipt point, receives a large share of its nomination in the confirmation process, and then only flows a small percentage of the volume that was confirmed. This over-nomination behavior reduces opportunities for other shippers who may have flowed gas if awarded the space. During periods of scarcity, scheduling non-performance can exert upward pressure on the market value of pipeline capacity and increase costs to end-users. Scheduling non-performance can also reduce revenues for the pipeline.

Under the Gas Accord, PG&E developed a process in Gas Rule 21, Section B.4, to levy a noncompliance charge for excessive scheduling non-performance behavior by a shipper. The current process and charge, however, is cumbersome to administer and is not able to manage this over-nomination problem when it occurs.

PG&E proposes to eliminate the current scheduling non-performance language in its tariffs, and replace it with a simpler and more direct process that reduces a shipper's ability to engage in scheduling non-performance.

PG&E proposes to limit the maximum daily quantity (MDQ) of any as-available contract for backbone transmission service to the expected usage of that contract by a shipper. Under PG&E's current procedures, a customer, with appropriate credit, can request an as-available contract quantity up to the capacity of the pipeline. For the purposes of this proposal, PG&E defines expected usage as a shipper's highest actual usage in the past 12 months. If a shipper's usage increases, the shipper may contact PG&E to have the MDQ increased. As part of the proposal to manage scheduling non-performance, PG&E also seeks authorization to reduce, on a daily basis, an as-available contract's MDQ to the previous day's actual usage, if scheduling non-performance is occurring.

f. Bypass Transportation Charge Proposal

(1) Introduction

PG&E believes that shippers on PG&E's transmission system have the potential to use third-party storage to bypass PG&E's transportation charges, should these third-party storage providers connect to a customer owned private transmission or gas gathering pipeline. This could result in the bypass of PG&E's local transmission charge, or the bypass of PG&E's backbone transmission charge. PG&E asserts that as a result of the bypass, other customers suffer economic harm because they end up having to pay for the bypassed charges. PG&E is harmed because it is unfairly deprived of revenues that are needed to provide its services.

PG&E recently filed a complaint case against Calpine, LGS and others in Case (C.) 03-07-031 alleging that bypass has occurred.

(2) Potential Bypass of Local Transmission Charge

Private transmission pipelines, end-use customers and gas gathering facilities that connect to facilities[17] owned by a third-party storage operator may be able to bypass PG&E's local transmission charges without PG&E's knowledge. This could occur in the following manner. The private pipeline that connects to a third-party storage facility would be able to nominate gas from PG&E's backbone system for delivery to the third-party storage facility, and then

[17] PG&E contends that these third-party storage facilities could be either the storage field or the pipeline that connects these facilities to PG&E's transmission system.

later withdraw the gas directly into the private pipeline for transportation to the private party's end-use facility. Since PG&E would not meter this gas, the customer could avoid PG&E's local transmission charges, customer access and customer class charges, including applicable Commission social and environmental costs and G-SUR charges.

The bypass opportunity is created because deliveries from PG&E's backbone to third-party storage operators are exempt from paying for local transmission and other end-user charges. This exemption was developed under the assumption that the gas put into third-party storage would eventually be delivered to end-use customers through PG&E's pipeline and metering facilities where local transmission and other end-user charges could be measured and billed. Such an assumption would no longer be valid if private pipelines serving their own end-use facilities directly could avoid local transmission charges by flowing their gas through third-party storage facilities.

(3) Potential Bypass of Backbone Transmission Charge

Backbone bypass could occur if gas-gathering pipelines or new interstate pipelines connect to third-party storage facilities, and then delivery of this gas is through PG&E's transmission system using the zero rate Mission-on path backbone transportation service. Such action would allow a shipper to avoid paying the Silverado Path rate that would have been charged if the gas were delivered directly to PG&E's system.

(4) Bypass Charge Proposal

PG&E proposes that the Commission require all third party storage operators under the Commission's jurisdiction to file a monthly report and to register all pipeline interconnections to its storage facilities. Such registration would establish the identity of the owner of the interconnected private transmission or gas gathering pipeline. The monthly report would summarize the total metered deliveries and receipts at each interconnect, and the total amount of storage gas currently held by the third-party storage operators in storage for all original gas deliveries. The gas delivery may be owned either by the owner of the interconnect or by another party who was sold the gas or took an inventory transfer of the gas.[18]

If the metered deliveries from the private pipeline to the third-party storage operator are greater than the receipts (deliveries from the third-party storage operator to the private pipeline) plus the amount of gas held in storage, then it should be presumed that the private pipeline owner has chosen to withdraw this gas and delivered it to PG&E under the Mission Path at a zero rate, having never paid for the backbone transportation (Silverado Path) service being used.

If the metered deliveries from the private pipeline to the third-party storage operator are less than the receipts (deliveries from the third-party storage operator to the private pipeline) plus the amount of gas held in storage, then it should be presumed that the private pipeline owner has transported a net amount of gas to their end-use facility. Since this net amount of gas originally

[18] PG&E believes that the Commission should require the third party storage provider to make a monthly report of all transactions that result in a change of title of gas volumes that move from or to the storage accounts of customers and producers that delivered gas via the on-system backbone connection to PG&E and the storage accounts of the interconnections to the private pipeline or gas gathering pipeline. The third-party storage provider should also report all transactions where the gas title changes between the storage accounts of the varying interconnects to the third party storage provider.

traveled to the third-party storage facility on a PG&E backbone transmission tariff, the end-user is obligated to pay the rates under Rate Schedule G-NT or G-EG end-user tariff for that gas.

Depending on the outcome of this calculation, and only if a private pipeline's metered deliveries, receipts and storage inventory are not in balance, PG&E proposes to collect the transportation charges avoided by this customer by billing the owner of the private pipeline or gas gathering pipeline the applicable as-available rate for either Silverado path service or for transmission-level G-NT or G-EG end-user service. If the owner of the private pipeline is not a customer of PG&E, then the Commission should require that the third-party storage provider be responsible for billing the customer and reimbursing PG&E for the services provided by PG&E. The Commission should also require the third party storage provider to include this requirement in its tariffs and place the private pipeline owner on notice that they will be responsible for these charges if their accounts don't balance.

PG&E's bypass proposal is to help enforce the Commission's long-standing rate policy that PG&E's local transmission charges are non-bypassable for all end-users in PG&E's service territory.

4. Other Proposals Affecting Transmission

Several customers propose that a backbone level rate structure be established in PG&E's service territory. Such a rate structure would allow a customer to connect directly to PG&E's backbone facilities without the payment of any local transmission charges. This issue is discussed more fully in the cost allocation section of this decision.

A related transmission cost allocation issue is PG&E's proposal to establish a four-tiered local transmission rate for noncore customers. This issue is also discussed in the cost allocation section.

B. Positions of the Parties

1. CCC/Calpine

a. Bypass Proposal

PG&E proposes to collect a bypass charge for third party storage service. PG&E asserts that such a charge is necessary in order to ensure that customers that use private pipelines to transport gas either to or from a third party storage field do not avoid paying for local transmission service or backbone transmission service.

CCC / Calpine oppose PG&E's bypass charge. CCC / Calpine contend that this situation no different from their backbone level proposal where a backbone level customer builds a lateral to take service directly from the PG&E backbone system. CCC / Calpine assert that backbone level customers should not be forced to pay for a PG&E local transmission service that they do not use, and customers that take gas from storage using private pipelines should not have to pay for local transmission services that they do not receive.

CCC / Calpine assert that similar reasoning applies to the second scenario where the Mission path is used. CCC / Calpine contend that to the extent the shipper does not use PG&E local transmission service, it should not have to pay local transmission charges. If PG&E is allowed to assess local transmission charges to customers using the zero cost Mission path rate to transport gas to the citygate, CCC / Calpine assert that PG&E is likely to double recover its local transmission charges. First, PG&E will collect local transmission charges from shippers moving gas to the citygate. Second, PG&E will collect local transmission charges from customers who move the gas from the citygate to their end-use facilities.

CCC / Calpine agree, however, that shippers who utilize PG&E's backbone facilities to transport gas to or from third party storage should pay an appropriate backbone level rate. Such a rate, however, should not include any local transmission charges unless the shipper actually receives local transmission service.

CCC / Calpine contend that it is inappropriate to impose a storage bypass charge because this will discourage the use of third party storage by customers. Given the many benefits of third party storage, the Commission should provide incentives to use third party storage, rather than disincentives.

b. Long-Term Contracts

CCC / Calpine oppose PG&E's proposal to offer long-term contracts for up to 15 year. They assert that the proposal has limited practical value to noncore end use customers because it does not offer any rate certainty, and the 15-year term is too long. The only party that would benefit is PG&E because it could tie-up customers for 15 years. This could foreclose potential competition from alternative service providers, while retaining the flexibility to charge any rate that may be approved by the Commission.

CCC / Calpine assert that PG&E's proposal would remove a significant portion of available capacity from the short-term market and make it available only for long-term contracts. Thus, customers will face the risk of either not having short-term capacity available when needed, or the capacity will be available but at a higher price, due to the upward price pressure from a limited supply of short-term capacity.

CCC/Calpine agree with ORA's objection that PG&E anticipates that it will be at risk for the difference between the negotiated contract rate and the tariff rate only until the next rate case. CCC/Calpine assert that PG&E has not presented any explanation, let alone evidence, supporting why it is appropriate that the risk for any shortfall in revenue should shift from PG&E to customers with the next rate case.

2. CMTA

CMTA recommends that PG&E's proposal for a 15-year contract be rejected. CMTA contends that the proposal does not offer rate certainty to customers, which customers need before committing to such a long-term. CMTA suggests that the Commission encourage a five-year rate settlement with PG&E for 2005 through 2009. Such a settlement would provide rate certainty.

3. California Natural Gas Producers Association

The California Natural Gas Producers Association (CNGPA) provided testimony on PG&E's bypass proposal. CNGPA takes the position that if the gas never touches PG&E's system, that no backbone or local transmission charges should be owed.

4. Duke

Duke objected to certain aspects of PG&E's proposal to offer optional 15-year contracts for transportation services without the need for Commission approval of each such contract. In PG&E's rebuttal testimony, PG&E clarified that any such long-term arrangements would be optional, and that the capacity affected by any contracts for more than five years would be limited to 400 MDth/d on the Redwood Path and 200 MDth/d on the Baja Path.

PG&E also stated in its rebuttal testimony that it was open to negotiated long-term contracts, but noted that any negotiated rate would need to be tied to current rates. Duke notes that the absence of rate certainty requires the customer to assume the risk of forecast error while the utility benefits by having a firm commitment for whatever future capacity price is charged.

While PG&E's clarifications improve PG&E's proposal, Duke notes that the Commission may want to retain its ability to review contracts with terms of more than five years.

5. LGS

LGS does not oppose a bypass charge under the proper circumstances. However, PG&E should not be allowed to institute a charge based on speculation and anxiety, nor should it be allowed to charge customers for services they do not use. Before a bypass charge is imposed, LGS asserts that there needs to be proof that such a charge is needed, and a complaint proceeding would be more appropriate.

LGS contends that there is nothing in the transcript of this proceeding that points to the existence of bypass. Until bypass is shown, LGS contends it is a waste of the Commission's time and resources to debate such an issue. LGS recommends that PG&E's proposal for a bypass mechanism be denied, or that it be denied as premature.

In the event the Commission decides to look into this issue, LGS suggests that a working group be formed to address the issue. The working group could include PG&E, the third party storage providers, and any customer that PG&E believes may be engaging in bypass. The working group could then provide a report to the Commission, who could then decide what steps to take next.

If the Commission decides to adopt a bypass charge at this time, the Commission should make clear that third party storage providers may collect from PG&E their costs of acting as PG&E's billing agent. LGS is not in the business of billing and collecting for other entities. LGS would have to undertake additions to its systems if it were required to act as PG&E's billing agent. Such charges include LGS's expected return on the investment LGS would have to make in these incremental systems, as well as full reimbursement of other related costs.

6. NCGC

PG&E proposes that it be permitted to offer contracts for firm backbone service for up to 15 years for standard firm service. The amount of firm capacity that would be available for up to 15 years would be limited "for the period covered by this proceeding" to 400 Mdth/d on the Redwood path, and 200 Mdth/d on the Baja path. These amounts represent about 20% of the capacity available on the two paths.

NCGC supports the concept of long-term agreements for backbone transmission capacity, but disagrees with PG&E's proposal that shippers who request long-term firm capacity must agree to pay the "standard firm tariff rate" for that capacity. Since the standard firm tariff rate is calculated on the basis of forecasted system load factors, the rate will change as system capacity utilization changes.

NCGC points out that a long-term contract customer assures PG&E of recovery of the revenue requirement associated with the contracted capacity. NCGC contends that pricing should reflect that assurance. Thus, the reservation charge that is billed for capacity held under a long-term contract should be based on the design capacity of the backbone pipeline, rather than the forecasted system load factor. In addition, the industry norm is to base demand charges for long-term capacity on design capacity, such as the demand charges on interstate pipelines.

NCGC contends that PG&E's proposal to impose the risk of system throughput variation on a customer creates the potential for PG&E to over-recover the costs of the transmission system.

7. ORA

ORA contends that the scope of this proceeding is not broad enough to consider all of the implications of PG&E's bypass proposal. Such an analysis must consider the impact on PG&E's revenue requirements. ORA suggests that the bypass proposal be reviewed in a more comprehensive proceeding.

PG&E proposes that it be allowed to enter into negotiated long-term contracts for firm backbone capacity. ORA is concerned about how this proposal will affect the treatment of any revenue shortfall resulting from such contracts. In PG&E's rebuttal testimony, PG&E states that if the negotiated contract rate differs from the tariff rate, that PG&E would expect to be at risk for the difference until the next rate case. ORA contends that this testimony suggests that PG&E expects to pass the risk of any revenue shortfall on other ratepayers. Under the Gas Accord, PG&E is at risk for any revenue shortfall. PG&E has not offered any explanation as to why the risk for the revenue shortfall should shift from PG&E to ratepayers. ORA contends that if PG&E enters into a negotiated long-term contract, that PG&E should remain at risk for the difference between the contract rate and the tariff rate. PG&E should not be allowed to automatically pass the risk of these contracts onto other ratepayers. To do so would eliminate any incentive for PG&E to protect the ratepayers from unreasonable costs associated with such contracts.

8. Wild Goose

PG&E expressed concern in its application about entities using third party storage providers, such as Wild Goose, to effect a bypass of its local and/or backbone transmission charges. PG&E's witness Campbell testified that this could occur in two ways. First, with respect to the potential bypass of local transmission charges, a private pipeline connected to a third party storage facility could nominate gas from PG&E's backbone system for delivery to a third party storage facility, and then later withdraw the gas directly into the private pipeline for transportation to an end-use facility. Since PG&E would not be metering the gas, the customer could avoid PG&E's local transmission charge. The second type of bypass is if a third party pipeline is connected to a third party storage facility, gas could be injected into storage, and then delivery of the gas could occur on PG&E's transmission system using the zero rate Mission path transportation service. This would bypass the backbone transmission charge.

PG&E proposes that the third party storage providers assist PG&E in collecting the revenues which have been bypassed. Wild Goose is not opposed to the implementation of a proposal that compensates PG&E for revenue loss when a customer utilizes PG&E's system in a manner which avoids paying certain charges to PG&E. Wild Goose's parent company has encountered this situation on other pipelines, and has been able to negotiate tariff provisions satisfactory to all parties.

In order to implement such tariff provisions, Wild Goose contends that the methodology used for capturing the bypass revenues must be practical, and that PG&E must not overreach in its efforts to capture bypass revenues. PG&E may be overreaching by insisting that any accounting method must take into account the possibility of trades and exchanges that occur within the storage facility. Wild Goose contends that accounting for trades and exchanges within a storage field is burdensome, and is not needed to make PG&E whole with respect to any potential bypass.

Wild Goose contends that the focus should be on whether PG&E has been kept whole over the transaction cycle. In order to do so, one should assess what has happened at the interconnect between PG&E and the third party storage provider. If the deliveries balance, *i.e.*, PG&E receives the same volume of gas back from the storage facility as was injected into the storage facility, then PG&E has been kept whole with respect to its transportation revenues. The fact that the 100 million cubic feet that went into the facility, is different than the 100 million cubic feet that came out, is irrelevant. Any adopted transmission bypass charge should recognize that such a charge should be assessed on a net basis, rather than transaction by transaction.

9. PG&E

a. Bypass Proposal

An issue that PG&E believes the Commission must address is the current or potential use of third party storage to bypass PG&E's transmission charges. Although PG&E believes that such interconnections are unlawful, PG&E proposes that an appropriate transmission charge be paid whenever there is a bypass of the transmission charges using third-party storage services.

PG&E contends that the bypass can occur in two ways. The first is bypass of local transmission charges. This occurs when gas is moved on PG&E's backbone system to a third-party storage facility, and then is redelivered to an on-system PG&E customer using a private pipeline connected to the storage facility. Under the Gas Accord, all gas that moves on PG&E's backbone system for final delivery to an on-system PG&E customer must pay local transmission charges and other applicable charges. Under the bypass situation, the on-system PG&E customer who uses a private pipeline connected to the storage facility could avoid payment of the local transmission charges because PG&E is not likely to know about the subsequent delivery from the third-party storage facility to the end-use customer.

The second bypass situation arises when pipelines receiving California gas production or new interstate pipelines connect to third-party storage facilities, and the gas is then delivered to PG&E's transmission system using the zero rate Mission Path backbone transmission service. This type of bypass can also occur if a private pipeline connected to the third-party storage facility delivers gas to that storage facility. The bypass can also arise if the gas is transported directly from the gas gathering line into the third-party storage operator's pipeline and then delivered immediately to PG&E's transportation system. These situations allow the shipper to avoid having to pay the Silverado Path rate that would have been charged if California gas production were delivered directly to PG&E's system; or avoidance of the Redwood or Baja rates if interstate gas were delivered through the storage facility to PG&E's system.

PG&E proposes that the Commission authorize PG&E to charge for transmission bypass that occurs through a connection to third-party storage facilities. PG&E points out that neither LGS nor Wild Goose oppose establishing a mechanism to collect the appropriate transmission charges that were bypassed. PG&E proposes that the charge be based on a calculation which measures the net flow between the third-party storage facility and PG&E. Depending on the outcome of the calculation, and only if a private pipeline's metered deliveries, receipts and storage inventory, including inventory transfers or exchanges, are not in balance, PG&E proposes to collect the transportation charges avoided by this customer by billing the owner of the private pipeline or gas gathering pipeline the applicable as-available rate for either Silverado path service or for transmission-level G-NT or G-EG end-user service. In the event the owner of the private pipeline is not a customer of PG&E, then the Commission should require that the third-party storage provider be responsible for billing the customer and reimbursing PG&E for the services provided by PG&E. PG&E recommends that the Commission approve PG&E's proposal in concept, and order LGS, Wild Goose Storage, and PG&E to work together on the necessary agreements, calculation methodologies, and tariff changes to implement the bypass charges.

LGS proposes that it be reimbursed by PG&E for accounting and collection activities if PG&E's bypass charge proposal is adopted. PG&E opposes the reimbursement proposal because the bypass of PG&E's transmission rates provides third-party storage facilities with additional market opportunities, and such costs should be recovered from these market revenues.

Assuming that the Commission approves a backbone level rate, and assuming that a third party storage provider may permissibly interconnect with gas facilities other than those owned by PG&E, which is an issue PG&E contends has not been presented in this proceeding, PG&E would agree with CCC/Calpine that local transmission charges would not apply to deliveries from PG&E's backbone to third party storage, and then to an end-user who utilizes facilities that are owned by the end-use customer.

PG&E contends that the CCC/Calpine suggestion that PG&E would charge twice for local transmission service is mistaken. PG&E states that for deliveries of California production to PG&E using the zero cost Mission Path, PG&E proposes to charge the bypassed Silverado Path transmission rate, not local transmission charges. The local transmission charges would apply to the on system end user that eventually receives the gas.

PG&E asserts that the record clearly demonstrates the potential for bypass using LGS storage facilities. LGS admits that it has at least two interconnections with a private pipeline that could be used to bypass legitimate PG&E charges. PG&E contends that it needs to know whether transmission bypass is occurring, and an accounting process will help monitor and quantify this bypass. PG&E states that the Commission should order that an accounting process be established to verify whether bypass is or is not occurring. If no bypass is occurring, no transmission charges to redress such bypass will be levied. Whether or not bypass is occurring now, PG&E's proposal is simply requesting a date to determine the extent of such bypass, if any, and thus be able to collect the otherwise applicable PG&E transmission charges.

b. Long-term Contracts

PG&E proposes that shippers be allowed to voluntarily contract for standard firm backbone transmission service for up to 15 years without Commission approval for each contract. Currently, contracts that are five years and longer require Commission approval. (*See* D.86-12-009 [22 CPUC2d 444, 470-471].) For the period covered by this proceeding, PG&E proposes that the amount of firm capacity for the long-term contracts be limited to 400 MDth/d on the Redwood path and 200 MDth/d on the Baja path. This represents about 20% of the available firm capacity. PG&E contends that the long-term contracts will benefit customers who need long-term gas transportation and supply contracts, and provide assurance that if capacity is needed that it will be paid for by the shippers.

In response to some of the parties, PG&E is willing to look at long-term contracts for 15 years with a negotiated take, term, and price. However, the Commission would need to authorize PG&E to allow it to enter in such negotiated long-term contracts. If such authorization is granted, PG&E would include these contracts in its Negotiated Contract Report that is filed monthly with the Commission.

PG&E points out that allowing contract terms up to 15 years is only another option for the market, and if customers do not value this option, they will not sign such contracts. Some customers, however, may want long-term backbone contracts. These long-term contracts would be at standard rates that are derived using the same rate design as all other standard backbone rates.

PG&E contends that the arguments raised by individual customers that no one would want a long-term contract option without rate certainty are frivolous because a single entity cannot assess the business needs of the whole customer class. PG&E contends that its proposal provides more options to customers. If a particular entity is not interested because it doesn't meet its individual need, that is no reason for the Commission to take the option away from others that might find value in the option.

PG&E does not support NCGC's request for a standard firm rate for long-term contracts that is based on the investment in associated facilities *i.e.*, based on design capacity. Such a requirement would shift costs to customers who have shorter-term contracts. PG&E contends there is no reason to design rates for backbone contracts with terms of 6 to 15 years differently from those with terms of 1 to 5 years.

PG&E states that there is no basis for the argument that the conservative amount of capacity that will be made available for the long-term contract option will be in such high demand that it will require bidders to bid SFV for 15 years to acquire any of this capacity. Several parties have argued in this case that there is no demand for long-term contracts. PG&E believes that the demand will be less than the amount PG&E proposes to offer. PG&E's intent for setting a limit on the capacity available to the long-term option was to provide customers with a mix of short-term and long-term capacity options, not to create scarcity.

c. Other Issues

PG&E proposes to modify the Commensurate Discount Rule so as to remove certain disincentives that PG&E is facing in meeting market needs. This would be accomplished by making certain changes to the tariff. No party has taken issue with this proposal.

PG&E proposes to eliminate the current scheduling non-performance language in its tariffs, and replace it with a simpler and more direct process that reduces a shipper's ability to engage in scheduling non-performance. Scheduling non-performance usually occurs when a shipper submits a large nomination for as-available service at a constrained receipt point, receives a large share of its nomination in the confirmation process, and then only flows a small percentage of the volume that was confirmed.

PG&E proposes that the replacement process limit the MDQ of any as-available contract for backbone transmission service to the expected usage of that contract by a shipper. Instead of the current process where a customer can request an as-available contract quantity up to the capacity of the pipeline, PG&E would define expected usage as the shipper's highest actual usage in the past 12 months. PG&E's proposal also calls for it being able to reduce, on a daily basis, an as-available contract's MDQ to the previous day's actual usage, if scheduling non-performance is occurring.

C. Discussion

1. Basic Backbone Transmission Services

PG&E proposes to maintain the same basic Gas Accord structure for backbone transmission services, as described by PG&E in Exhibit 1.

No one opposes the proposal to continue the Gas Accord structure for backbone transmission services.[19] We adopt PG&E's proposal to continue the Gas Accord structure for backbone transmission service. Other proposals that we adopt today, which affect this service, shall also be part of the structure for backbone transmission service.

2. Basic Local Transmission Services

PG&E proposes to continue the same basic Gas Accord structure for local transmission services, as described by PG&E in Exhibit 1. This includes the obligation of all customers who flow gas on PG&E's on-system backbone transmission path to pay for a share of PG&E's local transmission system.

The only concern that has been raised about continuing the Gas Accord structure for local transmission service is whether customers who are directly connected to the backbone should have to pay the local transmission charges. That issue is addressed in the Cost Allocation and Rate Design section of the decision.

No one else opposes any other part of the proposal to continue the Gas Accord structure for local transmission services. We adopt PG&E's proposal to continue the Gas Accord structure for local transmission service. Other

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[19] Cost allocation issues regarding the backbone are discussed in the Cost Allocation and Rate Design section.

proposals that we adopt today, which affect local transmission service, shall also be part of this structure.

3. Long-Term Firm Backbone Contracts

PG&E proposes to allow shippers to contract for firm backbone transmission service for up to 15 years for standard firm service. The amount of firm capacity available for long-term contracts would be limited to 400 MDth/d on the Redwood Path, and 200 MDth/d on the Baja path. This represents about 20% of the available capacity. Under PG&E's proposal, a shipper who requests long-term firm capacity must agree to pay the standard firm tariff rate, which is subject to change in future rate proceedings.

Several parties oppose PG&E's proposal that it be allowed to offer long-term transmission contracts for up to 15 years. They cite several reasons for their opposition. First, there is no rate certainty because the contract is tied to the standard firm tariff rate, which may change in the future. Second, PG&E anticipates that it will be able to raise its rates in these future proceedings for any shortfall that PG&E may experience from the long-term contract. Third, the proposal ties up too much capacity, which will result in higher short-term capacity prices.

PG&E's proposal is strictly voluntary for those customers who need long-term contracts. Before entering into a contract of up to 15 years, a potential customer will consider the available options, and determine whether a long-term contract is in the customer's interest. The uncertainty regarding what the future standard firm tariff rate will be, is just one risk factor the customer will analyze and consider. After analyzing and weighing the options, a potential customer will either enter into the contract or not.

The argument that the rates are uncertain suggests that very few customers will sign up for long-term contracts. If that happens, the concern about tying up too much capacity will not materialize. If the opposite occurs, the 20% limitation should provide customers with sufficient capacity to meet their short-term needs. Any long-term capacity that is not sold, will be used to provide short-term capacity.

Some parties are concerned that PG&E will seek to make up any shortfall that PG&E might experience in a long-term contract by seeking a rate increase. We note, however, that the same customers who voluntarily decide to enter into such long-term contracts, are free to participate in any proceeding which seeks to increase the rate that they are paying.

Given the concerns, and the flexibility that long-term contracts offer to certain customers, we adopt PG&E's proposal to offer long-term backbone transmission contracts for up to 15 years.

PG&E's rebuttal testimony states that it is open to having negotiable long-term contracts of up to 15 years, but the Commission would have to authorize this. Presently, negotiated contracts for up to five years are permitted. We are not prepared at this time to allow negotiated backbone transmission contracts for more than five years. The demand for long-term contracts should be examined before deciding whether negotiated contracts of up to 15 years should be permitted.

4. Commensurate Discount Rule

The Commensurate Discount Rule was adopted in the Gas Accord. (73 CPUC2d at 784.) The rule requires that whenever PG&E offers a discount on the Redwood path, that PG&E is required to contemporaneously offer a commensurate discount (*i.e.*, penny for penny) to all shippers for similar services on the Baja Path, and on the Silverado Path. PG&E seeks to change some of the language in the rule to remove certain disincentives that it faces when offering a discount.

Currently, the negotiated firm tariff is used as the benchmark for what defines a discount. PG&E proposes that a discount be defined as a rate below the standard firm rate for a negotiated firm service contract, or below the standard as-available rate for a negotiated as-available service contract.

None of the other parties provided any testimony on the commensurate discount rule, or commented on the issue in their briefs.

We have reviewed PG&E's justification for changing the language in the commensurate discount rule. The change allows PG&E to operate with more flexibility with respect to the offering of discounts. We adopt PG&E's proposal to change the rule.

5. Scheduling Non-Performance

To address the problem of scheduling non-performance, PG&E proposes to limit the MDQ of any as-available contract for backbone transmission service to the expected usage of that contract by a shipper.[20] PG&E's proposal also seeks to reduce, on a daily basis, an as-available contract's MDQ to the previous day's actual usage, if scheduling non-performance continues.

None of the other parties provided any testimony on the scheduling non-performance issue, or commented on the issue in their briefs.

PG&E's justification for this limitation is to reduce overnominations in connection with as-available backbone transmission service. As a result of

[20] PG&E defines "expected usage" as a shipper's highest actual usage in the past 12 months.

scheduling non-performance, it reduces the opportunities for other shippers who may have flowed gas if they were awarded the space. The non-performance also reduces revenues from the use of the pipeline.

We adopt PG&E's proposal to limit the MDQ of any as-available contract for backbone service to the expected usage of that contract by a shipper, and to reduce an as-available contract's MDQ to the previous day's actual usage, if scheduling non-performance continues.

6. Bypass Transportation Charge Proposal

As described in detail in the Background section above, PG&E proposes that the Commission adopt a requirement that all third-party storage operators under the jurisdiction of the Commission file a monthly report, and register all pipeline interconnections to its storage facilities. PG&E also seeks authority to charge for transmission bypass that occurs through a connection to third-party storage facilities.

This proceeding is the forum for adopting a gas market structure for PG&E's transmission system and the applicable rates. The bypass, or avoidance of, Commission-authorized charges is a concern from a revenue standpoint in this proceeding. However, this proceeding is not designed to determine whether bypass of these charges are occurring.

PG&E seeks a solution to remedy a possible problem. However, PG&E has not demonstrated that such a problem exists. PG&E seeks to require LGS and Wild Goose to impose monthly reports and to register its interconnects. The information which PG&E seeks, shifts the burden onto the storage providers to prove something which PG&E has yet to establish is occurring. This initial burden should rest with PG&E instead. PG&E must demonstrate with some certainty that a problem exists before we consider whether reporting and registration requirements should be imposed on LGS and Wild Goose.

The information which PG&E seeks is also a cause for concern. Under PG&E's proposal, the various pipelines connecting to LGS and Wild Goose would have to be identified, and various transactions would have to be reported. Much of this information describes in detail the operations of storage providers who offer a competitive alternative to PG&E's storage services.

We note that PG&E recently filed a complaint case against Calpine, LGS and others in C.03-07-031, alleging that bypass of transmission charge is occurring. In addition, Wild Goose and CNGPA filed a petition requesting the Commission to open an order instituting rulemaking to establish rules governing the interconnection between California gas production, independent storage providers, and the incumbent utility providers.

PG&E's proposal to impose a monthly reporting and registration requirement, and authority to charge for transportation charges which allegedly have been avoided, is not adopted. Should PG&E establish that such a problem is occurring, or if the Commission decides to address this issue, we will consider taking all necessary and appropriate measures in an appropriate proceeding to address this issue.

VI. Storage Services

A. Introduction

For 2004, PG&E proposes that its storage assets[21] continue to be allocated to the following three services: (1) Core Firm Storage service for CPGs; (2) system

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[21] PG&E's storage assets are operated by PG&E's California Gas Transmission (CGT) unit.

balancing service for the pipeline to provide monthly and daily balancing services; and (3) market storage services.

Under the Gas Accord, approximately 83% of PG&E's firm storage inventory rights, and associated firm injection and withdrawal rights, are assigned to PG&E's Core Procurement Department, for service to core customers. This firm storage is used to meet the winter reliability needs of core customers. Gas ESPs serving core customers are given the option to accept a proportionate share of the storage rights assigned to PG&E's Core Procurement Department. The gas ESPs contract directly with PG&E for the portion of Core Firm Storage rights accepted by gas ESPs under the provisions of PG&E's Schedule G-CFS. The remainder of PG&E's storage capacity is assigned to balancing, and to the noncore storage program (market storage services).[22] (*See* 73 CPUC2d at pp. 805, 808-809; Ex. 1, p. 6-5, Table 6-1.)

Gas injection and withdrawal from PG&E's storage facilities vary depending on the amount of gas in inventory. During the injection season, the injection rights of PG&E's Core Procurement Department are reset every two weeks, and its withdrawal rights are reset every week through the withdrawal season, based on its level of inventory in storage. Because their storage inventory is such a small portion of total storage, PG&E allows gas ESPs to have a fixed injection and withdrawal profile through the injection and withdrawal seasons.

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[22] Market storage services does not include firm storage that is assigned to core customers. Market storage services cover Standard Firm Storage, negotiated firm storage, negotiated as-available storage, and parking and lending services. Core Firm Storage customers may also use market storage services to supplement their core service or to purchase additional storage capacity.

PG&E's market storage services provide firm and as-available storage service. As-available storage services include parking and lending, which are also known as hub services. These market storage services promote higher utilization of pipeline transportation services during the lower-demand, shoulder months of spring and fall.

After the Gas Accord was adopted, D.00-05-049 made two changes to storage services. The first change was to allow self-balancing. Under self-balancing, customers can choose to opt out of PG&E's monthly balancing service and match their supplies and demand on a daily basis and receive a credit from PG&E. As of December 31, 2002, no customer has elected to use the self-balancing service.

D.00-05-049 also changed the rules regarding Core Firm Storage. Gas ESPs were given the option to reject some or all of their allocations of the Core Firm Storage capacity. The costs of Core Firm Storage were unbundled from core customer transportation rates, and collected in bundled customers' procurement rates, and from gas ESPs that choose to accept storage allocations.

B. Proposals

1. Assignments of Firm Storage Rights

PG&E proposes in 2004 to make fixed assignments of firm storage rights to the Monthly Balancing Service, Core Firm Storage, and Standard Firm Storage. Table 1 below details PG&E's proposed assignments for 2004.[23]

Table 1

Service	Average Injection[24]	Inventory[25] (MMDth)	Withdrawal on January 15th

[23] Table 1 comes from Table 6-2 of Exhibit 1.

	(MDth/d)		(MDth/d)
Monthly Balancing Service[26]	76	4.1	76
Core Firm Storage G-CFS	164	33.5	1,150[27]
Standard Firm Storage G-SFS	76	9.4	134[28]
Total	316	47	1,360

Under PG&E's proposal, storage rights for Monthly Balancing Service would increase compared to the Gas Accord. For Core Firm Storage, average injection and average withdrawal would increase, while inventory remains the same. For Standard Firm Storage, average injection and inventory for 2004 would increase, while withdrawal would decline. (*See* Ex. 1, Tables 6-1 and 6-2.)

2. Core Firm Storage Service

a. Basic Storage Services

PG&E proposes to expand the applicability of Schedule G-CFS to include PG&E's Core Procurement Department. This proposed change will ensure that all CPGs contract directly with PG&E's CGT for Core Firm Storage service, and are billed uniformly under the provisions of Schedule G-CFS. This change provides consistent treatment of CPGs for the assignment of both firm backbone

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[24] The storage injection capacities shown in the table include rented compressor units installed during the Gas Accord period.

[25] The amounts shown for inventory are the maximum inventory assigned.

[26] The amounts shown for balancing are for year-round injection and withdrawal capacity.

[27] The withdrawal right for G-CFS reflects the required withdrawal to meet the proposed core Winter Firm Capacity Requirement.

[28] The withdrawal right shown for G-SFS is the average assigned withdrawal for December through February.

and storage capacity. However, PG&E's Core Procurement Department will not have the option of rejecting its assignment of Core Firm Storage capacity, and will continue to receive any capacity rejected by gas ESPs.

For CPGs that accept an assignment of storage inventory of less than 1000 MDth, PG&E proposes to fix the firm injection and withdrawal rights for the season, as is done currently for small CPGs, instead of varying these rights with the customer's storage inventory level. The fixed withdrawal rights are set in proportion to the minimum withdrawal capacity that PG&E's Core Procurement Department must support, through the holding of inventory, to meet its Winter Firm Capacity Requirement. All CPGs that accept a share of Core Firm Storage capacity will be required to maintain their storage inventory at sufficient levels to support withdrawal rates consistent with the Winter Firm Capacity Requirement.

For CPGs with inventory levels beginning at approximately 1000 MDth, the physical injection and withdrawal capacities can vary significantly with the actual gas in inventory. A fixed injection or withdrawal right could intrude upon the storage rights of other customers. PG&E proposes that PG&E be allowed to vary the rights according to storage inventory levels for CPGs that obtain inventory rights greater than 1000 MDth.

No changes are proposed for how storage costs are recovered from bundled core customers or from gas ESPs. Bundled core customers will continue to pay for storage in their procurement rates, and gas ESPs that accept a storage assignment will pay a fixed monthly charge to PG&E.

b. Injection and Withdrawal Profiles for CFS

Table 6-3 of Exhibit 1 shows the capacity assigned to Core Firm Storage service for injection, inventory, and withdrawal, effective April 1, 2004. That table is reproduced below in Table 2. Overall, the average yearly ratio of injection to inventory to withdrawal is proposed to be 1.2:1:5.4. PG&E proposes that Schedule G-CFS injection and withdrawal rights vary based upon the volume of gas in inventory as shown in Table 2.

Table 2

Theoretical Service Date	Injection (MDth/d)	Estimated Inventory (MMDth)	Withdrawal (MDth/d)	Firm Rights Counter-Cyclical (MDTH/d)
October 31	113	33.5	0	50 - withdrawal
November 1	0	33.5	1,442	50 – injection
January 15	0	13.2	1,150	50 - injection
February 15	0	6.2	1,000	50- injection
March 31	0	1.0	761	50 - injection
April 1	211	0	0	50 - withdrawal

As explained in the Cost Allocation and Rate Design section, the core storage rate will reflect this seasonal profile. PG&E notes that by reducing the firm rights to better reflect their seasonal use, the core storage rate will be less than it otherwise would be if a higher level of firm rights is assigned.

c. Firm Counter-Cyclical Storage Rights for CFS

PG&E proposes to add firm counter-cyclical injection and withdrawal to Core Firm Storage service. The proposed service would provide 50 MDth/d of counter-cyclical rights for each day of the year. Table 2 above reflects the proposed counter-cyclical rights.

3. Standard Firm Storage Service

a. Basic Storage Services

PG&E proposes to develop a new tariff, Schedule G-SFS, Standard Firm Storage, to replace the existing Schedule G-FS, Firm Storage Service tariff. Proposed Schedule G-SFS provides more services than Schedule G-FS by offering more inventory, counter-cyclical injection and withdrawal rights, and the opportunity to secure a long-term contract.

PG&E proposes to offer a Schedule G-SFS customer firm injection, inventory, and withdrawal, in a fixed ratio of 2.2:1:3.1. (*See* Table 3.) This ratio defines the rate at which inventory can be filled and emptied, or injected and withdrawn. The withdrawal ratio is lower than that proposed for G-CFS because G-SFS customers do not require the high rate of withdrawal that is needed to meet residential and commercial temperature-sensitive demand.

By lowering the withdrawal ratio, all firm withdrawal rights can be met with lower pressure and a correspondingly lower inventory. Thus, less non-cycle working gas will be needed in the storage field to meet firm withdrawal rights. As a result, more gas in the storage field can be cycled as working gas, and more inventory can be offered to customers. The cycle inventory is the amount of gas that can typically be injected into and withdrawn from storage over the storage year, while supporting the injection and withdrawal rights of the firm storage customers. By reducing the withdrawal to inventory ratio for Schedule G-SFS, the inventory available to cycle can be increased from 40.5 MMDth to 47 MMDth.

PG&E believes that the increased cycle volume has more value to market storage services' customers than higher withdrawal rates. According to PG&E, these customers typically use storage services to control costs through price arbitrage in the seasonal cycles between spring and summer and fall and winter. They only need enough withdrawal capacity to withdraw their inventory during the high winter demand months of December through February and during the summer peak demand months of July through September. Core customers, on the other hand, derive more value from higher withdrawal rates in order to meet the temperature-sensitive daily winter demands of core customers from storage.

To increase the storage cycle inventory from 40.5 MMDth to 47 MMDth, PG&E will reassign 6.5 MMDth of non-cycle working gas. Of this gas, 2 MMDth will be retained and reclassified as working gas. This 2 MMDth of working gas will then be assigned to balancing, and used for the benefit of PG&E's transportation customers.

PG&E proposes that the remaining 4.5 MMDth of previously classified non-cycle working gas be sold to create room for customer owned gas. PG&E requests permission to sell the 4.5 MMDth of non-cycle working gas on a one-time basis for this purpose. PG&E proposes that any loss or gain from the sale of this non-cycle working gas be assigned to PG&E. PG&E's rationale for the assignment of any profit or loss on the sale of the gas to PG&E is because it owns the gas, and it has received only the short-term interest rate, rather than the utility authorized rate of return that is typical of most utility owned assets.

In Table 1, showing the assignment of firm storage rights effective April 1, 2004, more compression than is currently assigned under the Gas Accord will be needed to support the proposed 2004 firm storage rights. For 2004, PG&E proposes to use rental compressor units that were installed during the Gas Accord period to provide the additional firm injection. This rental compression added during the Gas Accord period is located below the flood plain at the McDonald Island storage facility.[29]

The Schedule G-SFS service will begin on April 1 of each year. The minimum term for G-SFS service will be one year, and service must be taken in one-year increments. The maximum term could be 15 years, as proposed below.

b. Injection and Withdrawal Profiles for SFS

Table 6-4 of Exhibit 1 shows the injection, inventory, and withdrawal rights curve for Standard Firm Storage service, effective April 1, 2004. That table is reproduced below in Table 3. Schedule G-SFS customers will be provided injection, inventory, and withdrawal in a fixed ratio of approximately 2.2:1:3.1. During the injection season, constant firm injection rights will be available to Schedule G-SFS customers until inventories are full. During the withdrawal season, each customer's constant firm withdrawal rights will be available, as long as gas volumes remain in that customer's contract inventory.

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[29] Should a flood occur causing the rental compression at McDonald Island to become inoperable, PG&E proposes to provide service to Core Firm Storage customers and monthly balancing first, and then to Schedule G-SFS customers, and lastly to remaining market storage services customers. In other circumstances where firm injection capacity is constrained, PG&E proposes to prorate all firm injection rights equally.

Table 3

Season	Average Injection (MDth/d)	Inventory (MMDth)	Average Withdrawal (MDth/d)
April - October	76	9.4	134[30]
November and March	76	9.4	75
December – February	0	9.4	134

PG&E proposes to offer firm counter-cyclical injection and withdrawal rights as part of its standard firm services. PG&E believes that the proposed counter-cyclical service will allow noncore customers to more effectively manage their natural gas needs, especially for businesses that have multiple-season cycles, or business cycles that run counter to the traditional core seasonal cycle. Due to the differences in gas storage demand for Schedule G-CFS and Schedule G-SFS customers, PG&E is proposing different counter-cyclical profiles for the standard firm service offering. For Standard Firm Storage service customers, PG&E proposes to offer counter-cyclical rights with greater maximum daily capacities than Core Firm Storage customers, but to limit the number of days their firm counter-cyclical rights are available.

For 2004, PG&E proposes that Schedule G-SFS customers be able to choose any three months of firm counter-cyclical withdrawal rights during the injection season of April 1 through October 31. This will allow customers who have peak demands for natural gas during the injection season, to obtain the right to withdraw from storage on a firm basis. For Schedule G-SFS customers, the

30 For the period April – October, each G-SFS customer will be allowed to select its own three months for counter-cyclical service from the seven-month season. The customer may choose any three months, consecutive or non-consecutive.

maximum daily counter-cyclical withdrawal rights that PG&E will offer is 135 MDth/d between April 1 and October 31.

Schedule G-SFS customers will also be offered counter-cyclical injection rights in November and March. These months allow Standard Firm Storage service customers to inject in November, to replenish inventory used in the summer or early fall, and to start injecting in March, prior to the traditional injection season, to replenish inventory that may be needed for summer peak use. For Schedule G-SFS customers, the maximum daily counter-cyclical injection rights that PG&E will offer is 76 MDth/d in November and March. No firm counter-cyclical injection is available through Schedule G-SFS in December through February.

4. Long-term Firm Storage Contracts

PG&E proposes that the maximum term for Schedule G-SFS or Schedule G-NFS (Negotiated Firm Storage) service be 15 years from the contract start date. PG&E proposes that customers who request long-term firm capacity must agree to pay the standard firm tariff rate, and therefore, will be subject to rate adjustments in future rate cases in which they can actively participate. PG&E states that long-term contracts will benefit customers, such as new power plant operators, who may be negotiating long-term, fixed-priced power sales and therefore need long-term gas transportation and supply contracts.

5. Negotiated Firm and As-Available Services

Except for the proposal that the maximum term for G-NFS service may be up to 15 years, as mentioned earlier, PG&E is not proposing any other changes to its current Schedules G-NFS or to G-NAS (Negotiated As-Available Storage) service.

PG&E offers negotiated firm storage service using the firm capacity that is assigned to the Standard Firm Storage service. Any injection or withdrawal capacity that is not used by firm storage customers is used to provide as-available storage services.

6. Hub Services

PG&E is not proposing any changes to its current parking and lending services, and such services should be retained without change.

7. Storage Shrinkage

PG&E proposes that all firm storage services, including Core Firm Storage, be subject to a storage shrinkage requirement upon injection. For Negotiated Firm Storage service, PG&E proposes that the storage shrinkage requirement be a negotiable element of the Negotiated Firm Storage service. The Operations and Balancing Services section describes PG&E's storage shrinkage proposal.

C. Position of the Parties

1. Duke

PG&E requests Commission authority to sell 4.5 MMDth of storage gas that had previously been classified as non-cycle working gas and to retain any gains or losses from the sale of that gas. PG&E's argument is that its shareholders should receive all of the proceeds from a sale of storage gas because shareholders received the short term interest rate on their investment.

Duke recommends that the Commission follow the precedent in D.02-11-028, and consider all the relevant factors before determining the allocation of the gain from PG&E's proposed sale of the non-cycle working gas. Duke asserts that the return that PG&E has received on the storage gas is just one element for the Commission to consider when it allocates any gain from the sale of the storage gas.

2. LGS

LGS points out that for core procurement groups to meet the Winter Firm Capacity Requirement, it will need an additional 75 MDth/d of withdrawal capacity. This additional capacity comes from a peaking arrangement between PG&E's Core Procurement Department, and PG&E's at-risk storage arm, California Gas Transmission. LGS is concerned about how this peaking arrangement was arrived at, and whether such an arrangement disadvantages third-party storage providers by shifting a portion of the at-risk storage to the core.

LGS also raised concerns about PG&E's request to reclassify and sell 4.5 MMDth of non-cycle working gas, with PG&E retaining all of the proceeds. LGS points out that since PG&E admits that this non-cycle working gas is necessary and useful in PG&E's utility operations, that PG&E should file § 851 application, or seek an exemption under § 853.

LGS is also concerned about the use of rental compression, which was installed for use as part of its at-risk storage operations. PG&E is now seeking to recover those rental compression costs through Standard Firm Storage services, balancing, and providing firm counter-cyclical injection rights to the core. LGS contends that the approval of PG&E's proposal will allow PG&E to shift almost 50% of the unrecovered costs of the rental compression to bundled customers. Since PG&E installed this rental compression at its own risk and without Commission approval, PG&E should be required to continue to bear those costs as part of its at-risk storage program. This gives California Gas Transmission an advantage over its storage competitors, who cannot shift costs in this fashion.

If the Commission is inclined to allow the use of the rental compression for the purposes proposed by PG&E, it should require PG&E to file an application for approval of the installation of the compression before any cost recovery from bundled ratepayers is allowed, and PG&E should be required to give notice of such an application to the parties to this proceeding.

3. NCGC

PG&E proposes to add firm counter-cyclical injection rights to the core's firm storage service. PG&E also proposes to assign 76 MDth/d to system balancing. NCGC believes that the allocation of injection capacity to system balancing service should be increased to 100 MMcf/d.

NCGC does not oppose the allocation of 50 MDth/d of counter-cyclical storage rights to the core, so long as the allocation does not jeopardize increasing injection rights to balancing service. To the extent there is insufficient storage injection capacity to increase the allocation of capacity to the core, while simultaneously increasing the allocation of installed injection capacity to system balancing, NCGC recommends that the allocation of injection capacity to the core for the winter months of December, January and February be reduced to the extent necessary to assure that there will be adequate injection capacity to provide the recommended level of system balancing.

4. ORA

ORA takes issue with PG&E's proposal to add firm counter-cyclical injection and withdrawal to Core Firm Storage services. ORA contends that it is not clear that core customers would benefit from such a proposal. Given the lack of need for this service, and the cost to the core of $550,000. ORA recommends that the proposal not be adopted.

5. PG&E

PG&E's storage assets provide firm and as-available storage service to core groups and to other market participants, and they also provide support for PG&E's system balancing service. PG&E proposes to reset the assignment of its firm storage capacity to balancing, Core Firm Storage, and Standard Firm Storage. PG&E's proposed modification to Core Firm Storage would increase core's firm withdrawal capacity by 75 MDth/d to meet the proposed Winter Firm Capacity Requirement. This would be accomplished by assigning existing capacity to Core Firm Storage through a peaking arrangement.

PG&E's proposed resetting of firm storage capacity would increase the amount of firm injection capacity to Core firm services, G-CFS. This would be accomplished by using the rental compression units that were acquired during the Gas Accord I period to support its sales under the at-risk storage program.

PG&E also proposes the following: (1) consolidate all core storage services under one tariff, Schedule G-CFS; (2) increase the cycled working gas inventory through the proposal sale of non-cycle working gas, and the reclassification of non-cycle working gas for balancing; (3) add firm counter-cyclical services to Schedule G-CFS and Schedule G-SFS; and (4) allow long-term storage contracts. PG&E contends that these proposals will provide its customers with more valuable services and an equitable cost allocation.

ORA asserts that PG&E has not made a sufficient showing that core customers would benefit from its firm counter-cyclical storage rights for core customers, and that the proposal should not be adopted at this time. PG&E's justification for assigning 50 MDth/d of counter-cyclical injection rights to the core is that PG&E believes the additional capacity will enable the core to better balance their supply and demand. PG&E's proposal on counter-cyclical rights should not be rejected simply because ORA chose not to participate in this issue. PG&E recommends that the Commission accept PG&E's proposed capacity allocation of firm counter-cyclical injection and withdrawal capacity to schedule G-CFS.

NCGC does not oppose the allocation unless the allocation jeopardizes increasing injection rights to balancing service. NCGC believes that PG&E

should assign counter cyclical injection capacity to the core only to the extent to which there is sufficient existing injection capacity after increasing the allocation of injection to balancing service. NCGC also believes that the allocation of injection capacity to system balancing service should be increased to 100 Mcf/d. PG&E states that it has already proposed to increase injection assigned to balancing and believes the proposed assignment of 76 MDth/d balances the interests of all market participants.

PG&E proposes to provide additional withdrawal capacity to Core Firm Storage to meet the Winter Firm Capacity Requirement through the use of a peaking arrangement, which has been in place since the beginning of the Gas Accord. Because PG&E has been providing this service yearly since 1998, PG&E has stranded cost concerns if PG&E's proposal to provide the additional 75 MDth/d withdrawal capacity using PG&E storage is rejected.

LGS inferred that the peaking arrangement was the result of some back office, shady deal. PG&E asserts that LGS' inference is simply wrong. PG&E contends that the peaking arrangement between California Gas Transmission and PG&E's Core Procurement Department is proper. PG&E requests that the Commission approve PG&E's proposal to provide the additional 75 MMDth/d of withdrawal capacity to the core by incorporating the peaking agreement into Schedule G-CFS. PG&E recommends that the Commission approve its proposed withdrawal assignment, which includes the 75MDth/d to Schedule G-CFS.

PG&E proposes to increase the storage cycle inventory from 40.5 to 47 MMDth. To accomplish this, 6.5 MMDth of non-cycle working gas must be reclassified, and 2 MMDth would be retained and reclassified as working gas and assigned to balancing for the benefit of PG&E's transportation customers. The remaining 4.5 MMDth would be sold to create room for the customer-owned gas. PG&E requests permission to sell the 4.5 MMDth of gas. PG&E proposes that any loss or gain from the sale of the non-cycle working gas be assigned to PG&E because it owns the gas and has been fully at-risk for it.

PG&E opposes the proposals of Duke and LGS regarding the sale and treatment of the 4.5 MMDth of non-cycle working gas. PG&E asserts that the gas to be sold belongs to PG&E because it received only the short-term interest rate over the years. Also, the non-cycle working gas has not been depreciated, and depreciation expense has not been recovered in storage rates. Since PG&E's shareholders have been at-risk for the investment in this asset, PG&E believes that it should receive all of the proceeds from the sale of the non-cycle working gas. PG&E contends its situation is different from the sale of the cushion gas by SoCalGas in D.02-11-028.

With respect to the use of rental compression, PG&E contends that there is no cross subsidy. PG&E is resetting all firm capacity rights, including those for the at-risk G-SFS program. Also, incorporating the added injection and the associated costs in core's assignment lowers the per unit cost of injection while adding considerable flexibility. PG&E recommends the Commission approve its proposal to enhance its storage services using low cost rental compression to support this effort.

With respect to the long-term storage contracts, PG&E proposes that the maximum term for Schedule G-SFS and G-NFS service be 15 years from the contract start date. PG&E proposes to follow the guidance set in D.93-02-013 regarding contracts for existing and new facilities.

NCGC proposes to limit the amount of capacity available for long-term contracts, and a market concentration limit for PG&E storage. PG&E disagrees with the capacity limitation because its noncore storage program is smaller than

LGS or Wild Goose. PG&E does not believe it should have to set aside a portion of its storage for short-term contracts when other storage alternatives are available. PG&E is also opposed to the market concentration limit unless such a limit applies to all three storage programs in Northern California and excludes firm storage capacity assigned to PG&E's Core Procurement Department.

D. Discussion

1. Assignments of Firm Storage Rights

PG&E proposes to make fixed assignments of firm storage rights to the Monthly Balancing Service, Core Firm Storage, and Standard Firm Storage. PG&E's proposed assignments of firm storage rights are shown in Table 6-2 of Exhibit 1. The assignments of firm storage rights also determines the allocation of the storage cost of service, as discussed in the Cost Allocation and Rate Design section. PG&E's proposed assignments are based on other proposals that PG&E seeks adoption of. To the extent other PG&E proposals are not adopted, this will affect the assignments of the firm storage rights.

Since we do not adopt the proposed Winter Firm Capacity Requirement, an adjustment to the assignments of capacity must be made. At page 4-8 of Exhibit 1, PG&E states that to meet the Winter Firm Capacity Requirement, "PG&E Core Procurement will need its current Gas Accord I assignment of PG&E's gas storage plus an additional assignment of 75 MDth/d of withdrawal capacity…." Since the Winter Firm Capacity Requirement is not needed, PG&E will just need the current assignment from the Gas Accord.[31] As shown in Table

[31] Since we are not adopting PG&E's proposed assignment of an additional 75 MDth/d of withdrawal capacity to Core Firm Storage, there is no need to address the peaking arrangement arguments. The issue about whether third-party storage providers can provide this service has also been addressed.

6-1 of Exhibit 1, and Table 14-7 of Exhibit 3, Core Firm Storage shall be assigned the following seasonal capacities for 2004: 156.6 MDth/d of injection; 33,477.7 MDth of inventory; and 1,111.2 MDth/d of withdrawal.

As discussed below, we deny PG&E's request to sell 4.5 MMDth of non-cycle working gas. As a result, the proposed inventory level for Standard Firm Storage will be reduced from 9.4 MMDth to 4.8 MMDth. This also affects the proposed injection and withdrawal because less inventory capacity is available. Therefore, as discussed below, we shall use the Gas Accord's current assignments for Standard Firm Storage as shown in Table 6-1 of Exhibit 1, and Table 14-7 of Exhibit 3, for 2004. Those assignments are: 22.4 MDth/d of injection; 4,782.5 MDth of inventory; and 158.7 MDth/d of withdrawal.

For balancing, as discussed in the Operations and Balancing Services section, we assign the following for 2004: 76 MDth/d of injection; 4.1 MMDth of inventory; and 76 MDth/d of withdrawal. The following Table 4 lists the assignment of firm storage rights for 2004.

Table 4

Services	Average Injection MDth/d	Inventory MDth	Average Withdrawal MDth/d
Balancing Service	76	4,100.	76
Core Firm Storage	156.6	33,477.7	1111.2
Standard Firm Storage	22.4	4,782.5	158.7
Total	255	42,360.2	1345.9

2. Core Firm Storage Service

a. Basic Storage Services

PG&E proposes that Core Firm Storage be provided under a single tariff, Schedule G-CFS (Core Firm Storage), to PG&E's Core Procurement Department and to other core procurement groups. PG&E's Core Procurement Department would not have the option of rejecting its assignment of core firm storage capacity, which is the rule that is in effect today.

No one has objected to PG&E's proposal to provide Core Firm Storage to both its Core Procurement Department and to core procurement groups under a single tariff, Schedule G-CFS. We adopt PG&E's proposal to use a single tariff.

For core procurement groups that accept an assignment of storage inventory that is less than 1000 MDth, PG&E proposes to fix the firm injection and withdrawal rights for the season. PG&E currently does that for the small core procurement groups. PG&E's proposal notes, however, that:

> "The fixed withdrawal rights are set in proportion to the minimum withdrawal capacity that PG&E Core Procurement must support, through the holding of inventory, to meet its Winter Firm Capacity Requirement. A comparable fixed injection right is also set for these smaller CPGs. All CPGs that accept a share of Core Firm Storage capacity will be required to maintain their storage inventory at sufficient levels to support withdrawal rates consistent with the Winter Firm Capacity Requirement." (Ex. 1, p. 6-10.)

Since we do not adopt the proposal for a Winter Firm Capacity Requirement for CPGs, the existing guideline in the Gas Accord to meet the core's winter needs shall be used to set the firm injection and withdrawal rights for the season for CPGs that accept an assignment of storage inventory that is less than 1000 MDth. The existing guideline to meet the core's winter needs is close to a 1-in-3 year cold temperature event.

(1) Firm Storage Injection, Inventory, and Withdrawal Profiles for Core Firm Storage

For CPGs that have inventory rights greater than 1,000 MDth, PG&E proposes to vary the injection and withdrawal rights according to its injection and withdrawal rights curve shown in Table 6-3 of Exhibit 1.

For 2003, the ratio of injection to inventory to withdrawal for Core Firm Service is about 1:1:5. For 2004, PG&E proposes that Schedule G-CFS injection and withdrawal rights vary based upon the volume of gas that is in inventory. For 2004, the overall average yearly ratio of injection to inventory to withdrawal is 1.2:1:5.4. (Ex. 1, p. 6-10; Ex. 15, p. 13.)

According to PG&E, the injection and withdrawal rights curve reflects the seasonal use of these assets by core procurement groups. By reducing the firm rights to reflect their seasonal use, PG&E states that the "core storage rate will reflect this seasonal profile," and "the core storage rate will be less than it otherwise would be if a higher level of firm rights are assigned." (Ex. 1, p. 6-11.) PG&E states, however, that the withdrawal rights profile "will be set equal to or above the levels necessary to meet the Winter Firm Capacity Requirement…." (Ex. 1, p. 6-11.) Since the withdrawal rights are tied to the Winter Firm Capacity Requirement, the injection and withdrawal rights curve in Table 6-3 of Exhibit 1, and the overall average ratio of injection to inventory to withdrawal, will likely be affected by our non-adoption of the Winter Firm Capacity Requirement. (*See* Ex. 15, p. 11.)

PG&E's seasonal adjustment in the injection and withdrawal rights curve appears to be of benefit in possibly lowering the core storage rate. However, we do not have sufficient information to allow us to develop a new injection and withdrawal rights curve, which reflects seasonal use only.

Since the injection to inventory to withdrawal ratio affects the cost allocation for storage rates, we shall adopt the Gas Accord's assignment of injection, inventory, and withdrawal, as shown in Appendix A at page 27, and which is reflected in Table 4 above. PG&E shall use the Gas Accord's assignments for Core Firm Storage in 2004, and shall use the Gas Accord's ratio of injection to inventory to withdrawal for Core Firm Service in 2004.

(2) Firm Counter-Cyclical Storage Rights for Core Firm Storage

PG&E proposes to add firm counter-cyclical injection and withdrawal to the Core Firm Storage service. This service would provide 50 MDth/d of counter-cyclical rights for each day of the year. The incremental cost to the core for counter-cyclical service would be $414,000.

ORA objects to PG&E's proposal to add firm counter-cyclical storage because no need has been shown for such a service. NCGC does not oppose the counter-cyclical storage rights to the core so long as the allocation does not jeopardize increasing the injection rights for balancing service.

We have considered the cost of such a service, and the flexibility that such a service offers. Given the relatively low cost of such service, and its ability to provide CPGs with additional flexibility to meet their gas needs during the non-injection season, we adopt PG&E's proposal for counter-cyclical service to Core Firm Storage.

3. Standard Firm Storage Service

a. Basic Storage Services, Non-Cycle Working Gas, and Compression

PG&E proposes the adoption of a new tariff, Schedule G-SFS, to replace the existing Schedule G-FS (Firm Storage) tariff. The new tariff schedule would offer more inventory, counter-cyclical injection and withdrawal rights, and the opportunity to secure a long-term contract.

The new tariff would include the offering of additional services or terms that PG&E is proposing. We adopt PG&E's proposal to have Schedule G-SFS replace its existing Schedule G-FS tariff. However, the new Schedule G-SFS tariff shall conform to the proposals that we adopt, and which are discussed below.

With respect to offering more inventory, PG&E plans to accomplish this through lowering the withdrawal to inventory ratio because Schedule G-SFS customers do not require the same high rate of withdrawal needed for residential and commercial temperature-sensitive demand. By lowering the withdrawal ratio, all of the firm withdrawal rights can still be met by using lower pressure and a correspondingly lower inventory. The lower inventory would allow PG&E to have less non-cycle working gas in the storage field. The lower amount of non-cycle working gas in the field creates more space for gas that can be cycled. Thus, more storage inventory can be offered to customers. PG&E states that by reducing the withdrawal to inventory ratio for Schedule G-SFS, the inventory available to cycle can be increased from 40.5 MMDth to 47 MMDth.

PG&E proposes to reclassify 6.5 MMDth of non-cycle working gas that would no longer be needed to meet the firm withdrawal rights. Of the 6.5 MMDth of gas, PG&E proposes to retain 2 MMDth and reclassify it as working gas to be used for the benefit of balancing PG&E's transportation customers.

For the remaining 4.5 MMDth of non-cycle working gas, PG&E requests permission to sell this gas on a one-time basis. PG&E contends that since it owns the gas, any gain or loss from the sale of this non-cycle working gas should be assigned to PG&E.

Duke and LGS object to PG&E's proposed sale of the 4.5 MMDth of non-cycle working gas.

There are several reasons why we deny PG&E's request to sell the 4.5 MMDth of non-cycle working gas. First, this proceeding is not the appropriate forum in which to seek permission to sell the gas. This proceeding addresses PG&E's gas structure for its transmission and storage systems, and rates, for 2004. To add a request to sell 4.5 MMDth of gas, in a one-paragraph reference in a multi-page document, is not appropriate given all of the other issues that confront us in this proceeding. (*See* Ex. 1, pp. 6-13 to 6-14.)

Our second reason for denying PG&E's request to sell the 4.5 MMDth of non-cycle working gas is PG&E's testimony lacks the necessary details for us to properly evaluate whether such a sale should be permitted. PG&E has not explained the origins of this non-cycle working gas, how much it paid for the gas, when it was acquired, the rate treatment that it has received for the gas, whether PG&E's storage operations justify such a sale, the projected amount PG&E is likely to receive for the gas, and how the gain or loss should be accounted for.

Our third reason is § 851 provides that no public utility shall sell "property necessary or useful in the performance of its duties to the public" without first seeking Commission authorization to do so. We agree with LGS' reasoning that PG&E should be required to file a § 851 application for the proposed sale of this gas. PG&E's briefs do not address the § 851 argument. PG&E acknowledges in its brief that the non-cycle working gas is providing the pressure to meet the storage withdrawal needs of its customers. (*See* PG&E Opening Brief, p. 38.) Thus, this proposed gas sale falls squarely within § 851. The concerns that we described in our second reason, should be addressed in a § 851 application so that the Commission has the information it needs to make an informed decision.

Accordingly, PG&E's request to sell the 4.5 MMDth of non-cycle working gas is denied without prejudice.

The issue regarding PG&E's proposed reclassification of 2 MMDth for balancing purposes, is discussed in the Operations and Balancing Services section of this decision.

PG&E's proposed assignment of firm storage rights, shown in Table 6-2 of Exhibit 1, requires more compression than is currently assigned. For 2004, PG&E proposes to use rental compressor units to provide additional firm injection for Schedule G-SFS, for balancing, and for providing counter-cyclical injection rights to the core.

LGS is opposed to the use of the rental compression, and points out that PG&E is at risk for the compressor units. To allow PG&E to reclassify the compressors so that the costs of such units are paid by captive core customers and/or captive transmission customers would be anticompetitive.

PG&E points out that it is at risk for selling enough services to recover the cost of its noncore storage services.

We will permit PG&E to use the rental compression equipment to provide the injection for Schedule G-SFS, for balancing, and for providing counter-cyclical injection rights to the core. The arguments of LGS and ORA are offset by the benefits the additional services provide to Core Firm Storage and to Standard Firm Storage customers, and for balancing.

(1) Firm Storage Injection, Inventory and Withdrawal Profiles for Standard Firm Storage

Table 6-4 of Exhibit 1 shows the average seasonal injection and withdrawal rights that PG&E proposes to assign to Standard Firm Service. Table 6-4 shows that Standard Firm Service would be assigned 9.4 MMDth of inventory.

Since we deny PG&E's request to sell 4.5 MMDth of non-cycle working gas, the inventory assigned to Standard Firm Storage will be reduced to 4.8 MMDth. This affects the injection to inventory to withdrawal ratio of 2.2:1:3.1. (*See* Ex. 15, p. 14.) The reduction in the inventory from 9.4 MMDth to 4.8 MMDth also affects PG&E's plans to lower the withdrawal ratio for Schedule G-SFS customers.

The injection to inventory to withdrawal ratio affects the cost allocation of storage rates. Due to the non-adoption of the sale of the non-cycle working gas, the 2004 inventory will remain at 4.8 MMDth. Since the inventory remains unchanged from the Gas Accord, we adopt the Gas Accord's assignment of injection, inventory and withdrawal for Standard Firm Service as shown in Table 6-1 of Exhibit 1, and which is reflected in Table 4 above. PG&E shall use the Gas Accord's assignments for Standard Firm Storage in 2004, and shall use the Gas Accord's ratio of injection to inventory to withdrawal for Standard Firm Storage in 2004.

(2) Firm Counter-Cyclical Storage Rights for Standard Firm Storage Service

PG&E proposes to offer counter-cyclical storage rights to Schedule G-SFS customers. Under this service, PG&E would allow Schedule G-SFS customers to choose any three months of firm counter-cyclical withdrawal rights during the injection season of April 1 through October 31. This will allow those customers who have peak demands during those months to withdraw gas from storage on a firm basis. Schedule G-SFS customers will also be offered counter-cyclical injection rights in November and March. The counter-cyclical injection is to allow those customers with peak demands in the summer and early fall to replenish their supplies.

On an annual basis, the average daily capacity allocated to Schedule G-SFS customers for counter-cyclical services is 47 MDth/d.

Except for LGS' concern about the use of rental compression, no one has objected to PG&E's proposed counter-cyclical storage rights for Standard Firm Storage Service. We adopt PG&E's proposal to offer this service for Schedule G-SFS customers. Based on PG&E's experience, there are some gas customers, such as food processors and electric generators, who need peak supplies during the injection season. The counter-cyclical service will provide Schedule G-SFS customers with additional flexibility to meet their gas needs, while allowing PG&E to market available counter-cyclical capacity.

4. Long-Term Firm Storage Contracts

PG&E proposes that the maximum term for Schedule G-SFS or Schedule G-NFS service be for 15 years from the contract start date. Under the existing procedures, individual agreements for longer terms can be negotiated, but must be filed with the Commission for approval. As part of PG&E's proposal, it would file any executed agreement that is longer than five years with the Commission for informational purposes.

Although Duke and NCGC expressed some initial reservations about the long-term firm storage contracts in their testimony, they did not comment about PG&E's proposal in their briefs. PG&E's rebuttal testimony and its opening brief, appear to have responded to their concerns.

In D.93-02-013, we approved long-term storage contracts for SoCalGas. (48 CPUC2d 107, 128-130.) PG&E contends that the long-term contracts will be of benefit to those customers, such as electric generators, who need long-term gas transportation and supply contracts. Given our previous approval of long-term storage contracts for SoCalGas, and the benefit that a long-term storage contract may bring to a customer, we will adopt PG&E's proposal to offer long-term contracts of up to 15 years for Schedule G-SFS and Schedule G-NFS customers.

5. Storage Shrinkage

PG&E proposes that all firm storage services, including Core Firm Storage, be subject to a storage shrinkage requirement upon injection. PG&E's proposal for storage shrinkage is discussed in the Operations and Balancing Services section.

VII. Contract Extension and Open Season

A. Background

PG&E proposes to implement a contract extension and open season process that is substantially the same as the process adopted for 2003 in D.02-08-070. The process would allow for the re-contracting of transmission capacity in 2004, and storage capacity for the 2004-2005 storage season.[32] The most significant departure for the open season, is that PG&E proposes to offer a limited amount of capacity for a longer term of up to 15 years, as discussed in the transmission section. Another difference is that negotiated transmission contracts may only be extended at the appropriate maximum allowable rate under the negotiated tariff. The details of PG&E's contract extension and open season process are set forth in Appendix A of Chapter 7 of Exhibit 1.

1. Summary of Proposed Contract Extension Process

If the Commission adopts PG&E's proposal to continue the Gas Accord market structure beyond 2003, PG&E believes that a re-contracting process is needed to allocate firm rights to PG&E's transmission and storage capacity in a

[32] The storage season runs from April 1, 2004 to March 31, 2005.

transparent and non-discriminatory manner. PG&E proposes a two-phase process for re-contracting for PG&E's transmission and storage capacity. In the first phase, PG&E proposes to allow existing firm contract holders in 2003 the option to extend their contract from January 1, 2004 until the earlier of the end of the proposed 2004 gas structure period, or the effective date PG&E's gas transmission assets are operated under the jurisdiction of the FERC, if this occurs. The option to extend would be offered to those that meet PG&E's creditworthiness standards as defined in PG&E's Gas Rule 25. The capacity holders would be allowed to re-contract for the same contract quantity as in their existing contracts, or less, as long as the requested contract quantity is reduced by an equal amount in all months.

If capacity holders have capacity for all 12 months of 2003, PG&E proposes that they be offered an option to extend capacity on an annual basis. Seasonal capacity holders would be allowed to extend in 2004 for the same months that were contracted for in 2003. If the capacity was assigned, PG&E proposes to provide the assignee with the contract extension option if the assignee was assigned the rights through the end of the contract. If the assignee was assigned the capacity for only a few months in 2003, and the capacity returns to the assignor before the end of the contract, PG&E proposes to offer the extension rights to the assignor. PG&E will also honor an agreement between the assignee and the assignor regarding who shall have the right to extend, if the parties send a letter to PG&E signed by both parties prior to the close of the contract extension period.

PG&E's contract extension option will be offered at the standard annual tariff rate for annual capacity, and at the seasonal tariff rate for capacity extensions of less than 12 months in a year. PG&E proposes to allow transmission contracts with negotiable rates and terms to be extended at the maximum allowable rate under the negotiated tariff or under the annual firm tariff if the contract is for 12 months.

PG&E proposes that negotiated firm storage capacity holders be offered a new extension price at the start of the contract extension process. The capacity holder can extend the contract at the new price, or release the capacity.

2. Summary of Proposed Open Season Process

The second phase of PG&E's proposal would take place following the contract extension process. PG&E proposes to hold an open season for any uncontracted annual Redwood or Baja capacity. PG&E proposes to offer up to 400 MDth per day of Redwood Path capacity and 200 MDth per day of Baja Path capacity for a maximum term of 15 years. PG&E would also offer in the open season any unsold or storage capacity not taken by shippers during the contract extension process. The open season would be open to all entities that meet PG&E's Gas Rule 25 creditworthiness standards.

For annual transmission capacity, open season participants will need to specify either the Redwood or Baja path, the delivered daily contract quantity, the contract's reservation charge structure (either SFV or MFV), and the term. PG&E does not propose to offer seasonal or negotiated contracts in the open season. All capacity requests would be binding.

PG&E proposes to limit the capacity requested on any path for any open season participant, including affiliated entities, to the capacity available in the open season. Any entity with a 50% or greater ownership interest in another entity will be considered an affiliated entity. Before applying the award criteria to the capacity requests, PG&E proposes to prorate all capacity requests from affiliated entities until the aggregate request for that path is equal to the capacity available in the open season.

PG&E also proposes to continue to limit the amount of total capacity that affiliated entities can be awarded in the open season and the contract extension process. In D.02-08-070, the Commission adopted a market concentration limit of 30% of the firm capacity, after the capacity set-aside for CPGs, wholesale customers, and SMUD's equity capacity. PG&E proposes the same market concentration limit for 2004. The maximum capacity limit for Redwood has increased to 410 MDthd from 400 MDth/d because of the recent increase in Redwood capacity. The capacity limit on the Baja Path would remain at 240 MDth/d.

PG&E proposes to continue to post the quarterly reports that were approved in D.02-08-070 on its Pipe Ranger web site during the 2004 period.

3. Participation of PG&E Department in the Open Season

PG&E's Core Procurement Department may require an additional 204 MDth/d of Baja capacity for 2004 to match the firm interstate capacity holdings at Topock. The amount of firm interstate capacity at Topock held by the core is to be decided in Phase II of the El Paso Capacity proceeding. PG&E proposes that any additional capacity for PG&E's Core Procurement Department be directly assigned to the core before the contract extension process. If additional Baja capacity is assigned to the core, the remaining Baja capacity may be insufficient to fully satisfy all customers who may want to exercise their extension rights for 2004. If this occurs, PG&E will prorate the extension rights and notify the customers of this before the start of the contract extension process.

PG&E still owns about 300 MW of gas-fired utility owned electric generation (UEG). PG&E proposes that UEG be permitted to participate in the open season for capacity in 2004, subject to the same rules and restrictions which were approved in D.02-08-070. Under those rules, UEG would be permitted to participate in the open season, and the UEG's capacity request would be subject to the same capacity request limits as the rest of the market. The UEG's capacity requests will be combined with those from PG&E's National Energy Group for purposes of determining the capacity request limit and the market concentration limit. UEG will also be required to submit its capacity request four business days prior to the open season deadline so that PG&E may provide cogenerators with notice of the UEG's bid as required under the cogeneration parity rules. PG&E also proposes to limit the amount of capacity that can be awarded to the UEG in the contract extension and open season process to its MDQ.

4. Other Proposals

Some parties have suggested that for contract extensions of negotiated contracts, the extension price should be the negotiated price. Others propose that a full open season be held, instead of having a limited open season after existing contracts have been extended.

NCGC proposes that the Pipe Ranger website list both the name of the capacity holders, and the amount of capacity reserved by these customers.

B. Position of the Parties

1. CCC/Calpine

PG&E proposes a new contract extension and open season process for re-contracting transmission capacity. Although the proposal is substantially similar to the extension process that the Commission approved in D.02-08-070, one major change is that PG&E proposes that holders of negotiated transmission contracts not be allowed to extend their contracts unless they agree to pay the maximum allowable 2004 rate under the negotiated tariff, or under the firm tariff if the contract is for 12 months. That is, under PG&E's proposal, all existing customers would be allowed to extend their existing backbone and local transmission contracts, except for those with negotiated rates. For the ones with negotiated rates, they must agree to increase their rate for service to the maximum tariff rate in order to extend their contract.

CCC / Calpine contend that this part of PG&E's proposal should be rejected. Instead of providing commercial certainty to gas industry participants, which is what PG&E's contract extension process is supposed to do, PG&E's witness acknowledged that rate increases for formerly negotiated rate customers would be a considerable disruption to their businesses. (4 RT 396.)

CCC / Calpine also assert that the proposed process is not fair because customers that previously had discounted contracts will likely not be able to justify a new discount over a one-year contract term, leaving the customer in an unfair negotiating position with PG&E for 2004.

PG&E argues that it should not be required to extend negotiated contracts at the negotiated rate. CCC / Calpine assert that all of PG&E's contracts for transmission service are regulatory creatures. If the Commission approves the extension of contracts at tariff prices, it can also approve the extension of contracts at negotiated prices.

CCC / Calpine contend that PG&E's witness acknowledged that the proposal for extending contracts could be unduly discriminatory because the Commission's non-discrimination requirement means that PG&E cannot provide unequal access to capacity or provide unequal treatment in respect to rates unless there is a legitimate justification. (4 RT 395.) Without a valid basis for refusing to extend negotiated contracts, that part of PG&E's proposal has a discriminatory effect. PG&E's proposal should be modified to conform its contract extension proposal to match the procedure adopted for negotiated contracts in D.02-08-070.

NCGC proposes that if the open season bids for 2004 transmission or storage capacity exceed the available transmission or storage capacity that remains after the roll over of the 2003 contracts, PG&E should then conduct a full open season for all transmission or storage capacity. CCC/Calpine contend that this proposal should be rejected. NCGC's proposal would essentially render PG&E's contract extension proposal moot if demand is greater than supply.

2. DGS

PG&E proposes to use a contract extension process followed by an open season process. Although the contract extension process allows current capacity holders to maintain their capacity, DGS contends that this process grants existing contract holders rights that are superior to other customers. DGS supports a new open season, rather than a process which favors the extension of existing contracts.

DGS suggests that the new open season provide end-use customers with a priority. To prevent gaming by end-users who have marketing affiliates, DGS suggests that the Commission and PG&E control the open season by barring bids that are in excess of expected demand. Only after end-use customers have been afforded all the capacity that they may desire, marketers and marketing affiliates should then be permitted to submit bids for capacity.

DGS also believes that the rights of PG&E as agent for DWR and the electric vendor need to be addressed. That is, should PG&E acquire backbone capacity to serve the contracts or does the vendor give the capacity to PG&E. The outcome of this could affect how PG&E does its job under the Fuel Supply

Plans. DGS states that this can be addressed as part of the approval of the Fuel Supply Plans for PG&E or as part of this decision.

At page 7-6 of Exhibit 1, PG&E proposes that the electric generators, including utility electric generators, be permitted to participate in the open season for capacity in 2004. DGS states that PG&E's UEG open season bidding in the Gas Accord was the single biggest cause of dislocation in the market. PG&E's UEG bid approximately 700 MMbtu /d for Redwood capacity, when the total open season offering for the Redwood path was about the same amount. Since PG&E seeks the capacity to be used with its peaker plants, DGS states that PG&E should be restricted to a seasonal bid, or a UEG bid should be restricted to its historic needs. Alternatively, DGS suggests that the Commission offer PG&E's UEG the volumes it seeks. If it is not needed by UEG, then PG&E could make the capacity available in the marketplace and return the revenue to an appropriate electric account.

3. NCGC

NCGC contends that there is no provision in the Gas Accord II settlement, approved in D.02-08-070, which permits 2003 contracts to be rolled over to 2004.

NCGC supports PG&E's proposal to roll over the 2003 transmission and storage contracts to 2004, unless the bids for remaining capacity for 2004 exceed the available capacity. If such a situation develops, NCGC advocates that a full open season be held for all of the transmission or storage capacity. NCGC contends that such a process would be fairer to those customers that did not hold capacity in 2003.

NCGC supports giving noncore end-use customers a preference for capacity through an open season process. NCGC asserts that an open season preference for end-users will assure that end-users have the opportunity, regardless of whether they actually make use of such opportunity, to gain upstream access from the PG&E citygate to interconnections with interstate pipelines and, ultimately, gas producers and marketers in producing basins. NCGC contends that such access can provide insurance against citygate price spikes and substantial basis spreads between upstream points and the PG&E citygate. Also, end-user access to backbone transmission capacity will promote greater competition among gas producers and marketers.

PG&E asserts that an end-user preference may create an incentive for gaming. An end-user that has a marketing affiliate could use its end-user preference to acquire capacity rights ahead of other shippers that may not have an affiliated end-user that can bid for them. NCGC contends that this possible gaming can be addressed by prohibiting an end-user from transferring capacity acquired through the exercise of the end-user preference to an affiliated marketer.

PG&E also notes that there is no need for an end-user preference because any end-user that holds capacity in its own name is very likely to receive a firm capacity award for 2004 if they submit a bid. NCGC contends that if this is likely to occur, there should be no concern about granting an end-user a preference.

NCGC's testimony states that the Pipe Ranger website currently lists the names of capacity holders. NCGC favors augmenting this information by showing the capacity reserved by these customers.

4. PG&E

PG&E proposes to implement a contract extension and open season process that is substantially the same as the one adopted for 2003 in D.02-08-070, with two changes. This process would take place in two steps. The first step is to allow existing firm contract holders in 2003 to extend their contracts through the 2004 period. In step two, an open season will be held for the remaining uncontracted annual transmission or storage capacity.

Two changes are being proposed for the open season. First, the open season will offer a limited amount of transmission capacity for a longer term of up to 15 years. Second, transmission contracts with negotiated rates will only be allowed to extend at the appropriate maximum allowable rate.

PG&E contends that this two-step process will promote stability in the gas market by providing commercial certainty to gas industry participants, provide stability while dealing with the Bankruptcy Court, and minimize potential disruption to PG&E customers.

NCGC asserts that there was no provision in the Gas Accord II settlement, approved in D.02-08-070, which permitted 2003 contracts to be rolled over to 2004. NCGC argues that the Gas Accord II settlement anticipated that a full season would be conducted for 2004 capacity. PG&E contends that the Gas Accord II settlement was silent on contracting for 2004, and did not anticipate that a full open season would be conducted for 2004 capacity.

NCGC suggests that if the demand for capacity exceeds the amount remaining after permitting the roll overs, that a full open season be held. PG&E contends that a full open season is not warranted and is not required, especially since this proceeding is only considering a one-year contracting period. PG&E also contends that it is unlikely that the requests for firm capacity will exceed what is available. PG&E also asserts that NCGC's proposal is not workable given the time constraints of having new contracts in place for January 1, 2004. PG&E also contends that invalidating contracts that have already been extended would be a bad idea. PG&E says that many customers may have hedged their positions, and terminating the contracts would have significant financial implications for such customers.

NCGC supports giving noncore end-use customers a preference for capacity during PG&E's open season. PG&E does not believe this is necessary because under PG&E's proposed contract extension process, end-users or their suppliers will continue to have capacity if they want it. In addition, the market demand for capacity by end-users is very low, and annual firm capacity requests have not exceeded the amount of firm capacity that is available. Also, NCGC's proposal is not desirable because not all end-use customers are in a position to hold backbone capacity. If the demand for firm capacity is high, and if end-users were able to bid for capacity for their marketing entities ahead of other gas marketing companies, some customers could be disadvantaged if their gas supplier could not obtain the appropriate amount of capacity to serve their needs.

CCC / Calpine suggest extending negotiated contracts at the negotiated contract price as part of the open season process. PG&E opposes such a request because it should not be forced to accept the terms of a negotiated contract that was entered into for a specific period of time under particular market conditions.

PG&E also opposes NCGC's proposal that PG&E post the firm capacity holdings of each firm shipper on the Pipe Ranger bulletin board. PG&E opposes the disclosure of this information because of the commercially sensitive nature of the data, and because there are other provisions in place for posting and monitoring market concentration data.

C. Discussion

PG&E proposes to allow existing contract holders to extend their transmission and storage contracts for 2004, followed by an open season for the remaining capacity. Other parties favor a full open season, or that a full open season be held if demand after the extension of existing contracts exceeds the remaining available capacity.

In order to address the type of process that should be authorized, we must return to the issue of what type of gas market structure should be authorized for 2004. As part of PG&E's proposed gas market structure for 2004, PG&E proposes that existing transmission and storage contract holders be allowed to extend their contracts into 2004 under certain conditions, and that any open season be held afterwards for any remaining capacity. The Gas Accord II Settlement Agreement, adopted in D.02-08-070, did not address what kind of process there should be for obtaining transmission and storage capacity for 2004. Thus, PG&E and the other parties were free in this proceeding to propose one or more processes to obtain transmission and storage capacity.

In deciding on what type of process should be adopted for the contracting of transmission and storage capacity, we are constrained by the time remaining before the start of 2004. Ideally, we would have preferred to have issued this decision earlier, which would have provided more time for instituting a process for obtaining capacity in 2004. To conduct a full open season now is impractical, given the late date. Had we more time, we could have addressed whether a full open season[33] or the process that PG&E proposes, would be the better choice for obtaining transmission and storage capacity for 2004. We do not need to address that issue in this decision given the time constraints. We will therefore adopt a

[33] The open season also raises the issues of whether end users should be given a preference, and whether such a preference will lead to problems with affiliated companies gaming the capacity that would be available during the open season.

process for obtaining transmission and storage capacity for 2004 as suggested by PG&E, and as discussed below.

PG&E's process allows existing contract holders in 2003 to extend their contracts for 2004. CCC / Calpine has raised the issue that negotiated contracts should be extended for 2004 based on the same negotiated price. We disagree with this argument.

A negotiated contract and a contract whose price is not subject to negotiation, are two different creatures. The person who takes service at a set price is usually not in a position to obtain a better deal, and must either take what is offered or refuse to take it. The person who has a negotiated contract is usually in a better bargaining position than the person who must take service at a set price. However, the price that is negotiated between the two parties depends on the bargaining positions of both, and the existing and future market conditions that affect the parties and the negotiated price. To allow an extension of a 2003 contract for 2004, at the same price that was negotiated in 2003, would be unfair to both parties. Current and future conditions may affect the price that was previously negotiated. Accordingly, PG&E is permitted to offer an extension of the negotiated contracts as set forth in PG&E's description of its proposed Contract Extension and Open Season process, that is found in Appendix A of Chapter 7 of Exhibit 1.

DGS raised two issues in its opening brief concerning transmission capacity. The first is the capacity rights for transmission of gas associated with the contracts of the California Department of Water Contracts (DWR). The second issue is that a limit should be placed on the amount of capacity that PG&E's UEG can obtain.

The transmission capacity to obtain the fuel for the DWR contracts was not raised in the testimony of any of the parties in this proceeding. Accordingly, that issue does not need to be addressed in this decision. Regarding limiting the amount of capacity that PG&E's UEG can obtain, we believe that PG&E's proposal contains adequate protections.

With respect to NCGC's suggestion to list the amount of capacity by shippers on its Pipe Ranger website, we do not adopt that suggestion. The amount of transmission capacity that a shipper holds could be sensitive business information, which should not be disclosed.

Accordingly, we adopt PG&E's proposal for a contract extension and open season process as set forth in Appendix A of Chapter 7 of Exhibit 1. PG&E is authorized to conduct this contract extension and open season process using the rates developed from today's adopted revenue requirement, related adjustments, proposals, and cost allocation and rate design methods.

VIII. Operations and Balancing

A. Background

PG&E proposes to maintain the general structure that is currently in place for operations and balancing services. This general structure is based on the Gas Accord Settlement Agreement provisions in D.97-08-055, the subsequent Operational Flow Order (OFO) settlement adopted in D.00-02-0050, and the Comprehensive Gas OII Settlement adopted in D.00-05-049. PG&E believes that all of these provisions form a workable and efficient foundation for managing the day-to-day operations of the PG&E pipeline system.

However, based on PG&E's operating experience with these provisions, PG&E proposes to make some changes to improve existing operational procedures, and to enhance the reliability, efficiency, and management of the

PG&E pipeline system. These proposals are set forth in Chapter 8 of Exhibit 1, and are summarized below.

1. Operational Overview

To operate a pipeline system, the system receipts (inflows) need to match system deliveries (outflows). This balance is needed to keep gas pressures and the resulting pipeline inventories high enough to meet the supply needs of customers, without allowing the pressures and inventories to become excessive, which can affect the safe and reliable operation of the gas system.

Under the terms and conditions of PG&E's tariffs, customers are required to deliver gas into the system that is approximately equal to their usage on a daily basis. In practice, there is rarely an exact match. Some customers may have significant under- or over-deliveries due to variations in their gas usage, uncertainty of supply, or other market-related causes. On most days, over-deliveries generally balance with the under-deliveries, which allows the pipeline to remain within normal operating limits.

On days when the overall pipeline imbalance is forecast to be outside the operating tolerances, PG&E calls OFOs or EFOs to activate specific daily balancing requirements and to impose charges for noncompliance. These flow orders, however, may not be sufficient to manage pipeline inventories under very cold, high demand conditions.

Under the Gas Accord, involuntary diversion of gas from backbone transmission shippers was designed to provide gas to core customers in the event of insufficient core supply. Involuntary diversions have not been needed since the start of the Gas Accord.

When local transmission capacity is constrained, curtailments are used to reduce or stop noncore gas usage so delivery can continue to all core customers.

Local transmission capacity constraints can be caused by very cold temperatures and high demands, or by emergency outages such as pipeline breaks.

The existing tariffs have no specific financial incentive to accurately manage daily imbalances. Currently, customer imbalances and imbalance statements are calculated on a monthly basis.[34]

There are three groups of end-user balancing entities that receive balancing service under Schedule G-BAL: CPGs; noncore customers who are part of a Noncore Balancing Aggregation Agreement (NBAA); and end-use customers without an NBAA. California producers that deliver gas to the PG&E pipeline system operate under the California Production Balancing Agreements (CPBAs), which currently have slightly different balancing rules.

Shrinkage is the result of using gas as compressor fuel, measurement errors, loss of gas due to venting for maintenance and safety, dig-ins by third parties, and leakage. Shrinkage is recovered through the delivery of in-kind gas by shippers. The Gas Accord Settlement Agreement specified the level of in-kind transportation shrinkage rates, or allowances. Experience with shrinkage led to PG&E reducing the shrinkage allowance on October 1, 2000 as requested in Advice Letter 2252-G.

2. Operations and Balancing Under the Gas Accord

In the Gas Accord Settlement Agreement, PG&E's Core Procurement Department was no longer responsible for balancing the pipeline. Instead, all

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[34] Although the Gas OII Settlement resulted in PG&E offering a self-balancing service, no one has elected to take this service since the hearings in this proceeding concluded. This self-balancing service requires daily measurement of the imbalances.

customers are responsible for balancing their own loads, *i.e.*, matching supply and usage on a daily basis.

The Gas Accord also provided customers with balancing flexibility within operating limits. As long as the system remains within prescribed operating limits, no daily imbalance limits apply, and customer imbalances are managed on a monthly basis. Customers are also allowed to carry forward a 5% monthly imbalance, positive or negative, into the next month. If imbalances exceed this amount, the imbalance must be reduced by trading with other customers or with a storage account. After the trading period is over, carryover amounts are cashed out, *i.e.*, balancing entities must pay the pipeline for under-deliveries or receive payment for over-deliveries under the terms of Schedule G-BAL. (*See* 73 CPUC2d at pp. 811-814.)

PG&E proposes six different modifications to balancing services, and six modifications to operations, which are described below.

3. Balancing Services Proposals

a. Background

PG&E's balancing services currently uses 50 MMcf/d of injection capacity to manage positive imbalances (*i.e.*, when scheduled supply is greater than actual usage), 70 MMcf/d of withdrawal capacity to manage negative imbalances (*i.e.*, when scheduled supply does not meet actual usage); and 2.2 Bcf of storage inventory. PG&E's first proposal is to enhance the balancing service by making five modifications, which are designed to reduce the frequency and severity of OFOs.

b. Additional Storage Capacity

The first modification is to allocate additional storage capacity to the balancing function. PG&E proposes to increase the injection capacity from

50 MMcf/d to 75 MMcf/d, the withdrawal capacity from 70 MMcf/d to 75 MMcf/d, and storage inventory capacity from 2.2 Bcf to 4 Bcf. (*See* Table 1.)[35] PG&E proposes that this additional inventory capacity be filled with 2 Bcf of gas, which would come from the proposed transfer of the non-cycle working gas as discussed earlier in the storage section.

PG&E proposes that additional storage inventory capacity be assigned to balancing because its operating experience has shown that the current storage inventory is inadequate. PG&E also cites a March 7, 2000 storage study, which indicated that allocating additional storage capacity to balancing may result in a proportionate reduction in OFO frequency.

c. Daily Imbalance Limit

PG&E's second modification to the balancing service is to establish a daily imbalance limit to the monthly balancing service requirements. PG&E states that large daily customer imbalances have been a major contributor to OFO events, especially during high pipeline inventory situations. The proposed daily imbalance limit is plus or minus 35% of daily usage, or plus or minus 30,000 Dth, whichever is larger. PG&E proposes a $0.25 per Dth excess imbalance charge for all daily imbalances that exceed the daily imbalance limit. PG&E proposes that any excess daily imbalance charge revenues be credited to the Balancing Charge Account (BCA), where they will be reallocated to all customers as determined in the Biennial Cost Allocation Proceeding (BCAP).

PG&E states that the daily imbalance limit is intended to reduce the imbalances that are created to take advantage of intra-month price arbitrage. The

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[35] The figures do not match because Table 1 is expressed in energy units, while the cubic feet amounts are in volumetric units.

proposed limit is lenient enough so it would be rare for a customer who is actively attempting to manage its balancing obligations to ever exceed this limit.[36] The daily limit is also intended to minimize the ability of the balancing agents to take advantage of a daily market price fluctuation by delivering multiple days worth of gas on a single day. The proposal will also allow the monthly balancing service to continue for the intended purpose of managing small variations in daily loads.

PG&E states that the daily imbalance limit should not be viewed as a right of the customer to be out of balance by 35%. Customers must still exercise their best efforts to have daily gas receipts match daily gas usage.

d. Monthly Excess Imbalance Charge

Under the current rules, customers are required to balance their monthly supply and demand within a 5% tolerance band. At the end of the month, they are allowed to trade imbalances with other customers or a storage account. Imbalances up to the 5% tolerance band are carried into the next month. After the trading period ends, the pipeline uses a cash-out mechanism to purchase remaining positive imbalances outside the 5% tolerance band, and to sell gas to make up negative imbalances. When a customer elects a cash-out, the imbalance is effectively transferred to the pipeline.

PG&E's third modification to balancing is to replace the current cash-out process with an imbalance charge for monthly imbalances in excess of the tolerance band. The imbalance charge would be a market-index based charge.

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[36] PG&E's testimony states that the daily imbalances incurred by all balancing entity groups during calendar year 2000 and 2001 shows that only 2% of the daily imbalances exceeded the proposed daily limit.

The entire monthly gas supply imbalance, including the quantity beyond the 5% tolerance, is then carried forward to the subsequent month. The customer is responsible for ultimately clearing its entire physical imbalance.

e. California Gas Production

PG&E's fourth modification to balancing is to apply the OFO and EFO tolerance bands and noncompliance charges to California production imbalances. Aligning the balancing requirements for California production with those of end-use customers during OFOs and EFOs will make it difficult for the parties responsible for nominating and balancing California production to exploit the current exemption from the balancing requirements.

Currently, the balancing rules for California production gas under the CPBA are different from the balancing rules for end-use customers. PG&E asserts that these differences have resulted in perverse incentives for some California production to be out of balance at critical times due to the lack of OFO or EFO noncompliance charges for California production gas.

PG&E states that the majority of California production gas is now managed either directly by end-use customers, such as electric generators, or by marketers or other agents providing gas to end-use customers. These kinds of entities are subject to flow order noncompliance charges. They have an incentive to nominate the California production supply, that is under their management, in a manner that provides a financial advantage for themselves by offsetting end-use customer imbalances to avoid OFO or EFO noncompliance charges. This behavior affects the physical imbalance on PG&E's system and creates or exacerbates OFOs and EFOs at the expense of others using the system.

PG&E points out that the data for California production gas nominations reveals that significant changes in daily nominations have occurred during

OFOs, without a corresponding change in gas well production. In addition, the data shows that there is a trend of California gas production imbalances exceeding the tolerance band required by the OFO. According to PG&E, this trend significantly reduces the effectiveness of the OFOs on the system as a whole, and can result in OFOs being called on subsequent days to the detriment of other shippers. In addition, these imbalances may result in the need for receipt point capacity allocations.

f. Measuring OFO and EFO Compliance by Core Procurement Groups

To provide the core market with more accurate benchmarks, PG&E proposes a fifth modification to balancing, which is made up of three proposals.

The first proposal is to change the timing of the forecast used for determining the CPGs' OFO and EFO compliance. Currently, the load used for calculating the compliance of a CPG with a flow order is the 24-hour forecast provided by the Core Load Forecast and Load Determination Service. This forecast is provided around 7:15 a.m. on the day before the OFO or EFO. Since noncompliance charges are based on this forecast, CPGs nominate gas supplies to match this forecast. However, relatively large core load swings can occur from day to day as temperature forecasts change. As a result, an OFO or EFO situation can be aggravated by the unavoidable inaccuracies in the day-ahead forecast.

Instead of using a day-ahead forecast, PG&E proposes that the CPGs' OFO and EFO compliance be based on the Determined Usage forecast, which is provided around 7:15 a.m. on the morning of the flow day.[37] The use of a same-day forecast will still allow sufficient time for the CPGs to make adjustments in their supply arrangements and nominations to avoid imbalance noncompliance charges, while taking advantage of later, more accurate usage estimates.

During very cold weather events, the financial impact of EFO compliance charges could be very large. Currently, compliance is based on the forecast of core demands. Due to the possibility that actual demands could be less than the forecast demand, the calculation of a noncompliance charge may be higher than it would be if the forecast had been accurate. To remedy this, PG&E's second proposal is that the EFO noncompliance charge for all CPGs be calculated using the lower of the Determined Usage forecast or the end-of-flow day core demand forecast. PG&E's third proposal is that the EFO noncompliance charges for CPGs be set at a higher level than for noncore customers. This will provide an additional incentive for marketers to flow gas to CPGs during an EFO.

4. Nomination Scheduling Process Proposal

The North American Energy Standards Board (NAESB) adopted "bumping"[38] as part of the standard nomination and scheduling process, and the FERC ordered all interstate pipelines to adopt the NAESB standards including bumping. At the time of the Gas Accord Settlement Agreement, bumping had

[37] If the 7:15 a.m. forecast is not available, then the most recent previous forecast would be used.

[38] "Bumping" refers to the process where a firm shipper in later scheduling cycles can bump, or supersede, an as-available nomination confirmed in a previous nomination cycle. Under the NAESB nomination and scheduling process, firm contracts can bump previously scheduled as-available nominations during the second and third nomination cycles. Under the NAESB standard, bumping does not occur in Cycle 4.

not been widely adopted. Bumping was included as part of the Comprehensive OII Settlement for SoCalGas adopted in D.01-12-018. In D.02-08-070, the Commission noted that changing the nomination protocol to implement "bumping" was an appropriate issue to consider in this proceeding. (D.02-08-070, p. 15, fn. 7.)

PG&E's current scheduling process involves four cycles and follows the timing standards established by NAESB, but does not include bumping. There are two nomination cycles on the day before the gas flows and two nomination cycles on the gas day. Within each cycle, firm service nominations have a higher priority than as-available service nominations. Anything that is scheduled in a previous cycle is unchanged in later cycles, unless a shipper de-schedules a previous nomination.

PG&E proposes to implement the bumping process used by NAESB as part of the 2004 nomination process. An example of how the NAESB bumping process would work is set forth in Exhibit 1 at pages 8-22 to 8-23.

PG&E believes that there is merit in having consistent rules between the other intrastate pipelines and interstate pipelines regarding bumping, and it provides assurance to firm shippers that they can utilize their contracts. Due to the lead-time to implement such a proposal, PG&E expects that the computer system modifications will not be ready until approximately seven months after a decision which authorizes the implementation of bumping.

5. Supply Shortfall Proposals

a. Curtailment Process Proposal

PG&E has two proposals to modify the operating procedures during supply shortfalls. The first proposal is to replace the current involuntary diversion process in the Gas Accord with a curtailment process.

Under the current involuntary diversion process, PG&E determines whether adequate supplies have been scheduled for core customers after the first scheduling cycle for the following gas day is completed, about 9:30 a.m., the day prior to the gas flow. If scheduled supplies for core customers do not equal or exceed the forecast core demand and the pipeline cannot serve all the load, then an involuntary diversion is needed. If a diversion is called, then a special scheduling cycle is created to implement the diversions. Under the special scheduling cycle, the pipeline diverts scheduled gas from noncore customers and provides it to CPGs that have scheduled supplies less than their forecast demand.

Although the involuntary diversion process has not been used during the Gas Accord period, the process of putting the systems in place to manage diversions, and PG&E's experience with EFOs, has identified some problems with the diversion process. First, the diversion process makes it necessary to suspend all pipeline scheduling activities after the first nomination cycle. This prevents additional storage and interstate supply from being scheduled during the involuntary diversion period, which could have helped relieve the extent of the usage reduction and mitigate the financial impact on customers. Second, the diversion process requires complex computer programming to perform pro rata allocations of backbone contract nominations to determine which noncore customer's supply is being diverted. This makes it very difficult for marketers and their customers to forecast the impact of the diversion on any individual customer prior to getting the final report. And third, the involuntary diversion process requires extensive communication in a short period of time between various parties.

PG&E proposes to eliminate the diversion process, and replace it with a system curtailment process. A system curtailment event would be called in conjunction with an EFO, and would be invoked when PG&E forecasts demand to exceed supply by such a level that service to core customers is threatened and noncore load must be removed from the system. The EFO will require all customers to limit usage to their available supply. When a system imbalance continues to be forecast, and service to core customers is threatened, a curtailment will reduce the noncore usage to bring the system into balance. Since curtailments are not based on scheduled supply, the scheduling process would continue, thus assuring that additional supply from transmission and storage can be scheduled throughout the curtailment period.

PG&E proposes that when a system-wide curtailment is necessary to ensure continuous, reliable service to core customers, that the required load reduction be shared across all noncore end-use customers on a pro rata basis. Allocating the curtailment to all noncore customers lessens the impact on any one customer, and allows them to continue to receive some level of gas supply. Under an extreme situation, all noncore customer load could be curtailed.

Prior to each winter season, customers will be provided with a benchmark allowed burn level. This allowed burn level will be based on the average daily usage from the customer's peak monthly usage during a previous winter season. The level of total forecast load relief needed from the curtailment event will dictate the percentage curtailment level from the customer's benchmark allowed burn level.

PG&E proposes that those end-use customers who fail to comply with the curtailment order be assessed a curtailment noncompliance charge, as discussed later. The payment of the noncompliance charge does not relieve the customer of the duty to resolve any other imbalances. That is, customers will still be required to make up any imbalance that may result from their unauthorized usage. PG&E may also shut off gas service to any customer who fails to comply with a curtailment order.

The gas supply that is scheduled for delivery to a customer during a curtailment event will continue to be scheduled to its account, and the customer will control the disposition of this gas supply. The customer may elect to market that gas supply to other customers or retain it for future use. Customers may sell their gas supply to a CPG through either a pre-arranged agreement, or on the day of the curtailment event. Under the proposal, there is no need for any gas supply compensation.

Also, under PG&E's proposal, there would be no compensation for curtailed customers because all noncore customers receive a lower reliability of service than core customers.

Due to implementation lead time, and the desire not to make this change during the middle of the 2003-2004 winter season, PG&E proposes to implement this proposal sometime after March 2004. This will allow the curtailment process to go into effect prior to the beginning of the 2004-2005 winter season.

b. Local Curtailment Noncompliance Charge

PG&E's second proposal to address a supply shortfall is to impose a local curtailment noncompliance charge for each decatherm of usage that exceeds the maximum allowable usage quantity.

Although local capacity constraints can occur at any time due to damage to the pipeline system, they are most likely to occur under high core customer load conditions caused by very cold weather. Prior to the winter season, PG&E runs simulations and provides each noncore customer in a constrained local curtailment zone with its maximum allowable usage quantity at three stages of local curtailment.

Once PG&E identifies that the temperature forecast in a local area is low enough, such that the local transmission zone will be constrained, PG&E will notify customers of the local curtailment stage beginning at 2:00 p.m., for curtailments needed for the next usage day starting at midnight. PG&E does not compensate curtailed customers during a local curtailment.

The existing local curtailment process, described above, will remain unchanged. However, PG&E proposes that there be a local curtailment noncompliance charge of $50 plus the Daily Citygate Index (DCI) price for each decatherm of usage that exceeds the maximum allowable usage quantity. Currently, there is no local curtailment noncompliance charge in the existing tariffs.

The payment of the noncompliance charge does not relieve the customer of the duty to resolve any imbalances, and the customer will be required to make up any imbalance that may result from their unauthorized usage. If there is an EFO or OFO in effect at the time of the local curtailment, the customer will also be subject to any EFO or OFO noncompliance charges. Any noncompliance charge revenue that results from a failure to comply with a curtailment order will be recorded in the BCA.

6. Shrinkage Proposals

a. Adjustment of Shrinkage Proposal

Shrinkage measures the difference between the gas that is received into the system and the quantity that is delivered to customers. Shrinkage is composed of: (1) lost and unaccounted for gas supplies (LUAF) and (2) PG&E's gas department usage (GDU) which includes compressor fuel. LUAF occurs for a number of reasons including: metering error, un-metered gas for operations, gas blown to the atmosphere to facilitate maintenance, and leakage. GDU is metered gas to fuel gas-driven compressors, gas processing equipment, and other gas facilities. Shippers on the pipeline are required to bring enough gas into the system to cover their customers' metered gas use plus an amount of shrinkage gas to cover the LUAF and GDU.

Under the Gas Accord structure, shrinkage gas is collected from transmission and distribution transportation volumes. This includes shrinkage related to gas used in the operation of PG&E's storage fields.

Due to the shrinkage over-collection following the adoption of the Gas Accord, PG&E requested and received permission to reduce its shrinkage allowances in August 2000. Presently, the shrinkage allowances are updated every two years or longer, depending on the regulatory schedule of the BCAP. However, changes in system operations that occur within the BCAP period may change the actual shrinkage that is experienced on PG&E's system.

PG&E proposes that for 2004, a process be adopted to update the shrinkage allowances on an annual basis. If changes to the shrinkage allowance are needed, PG&E proposes that this be accomplished through a compliance filing to be effective on the first day of each calendar year. The shrinkage allowances will be based on the adopted BCAP throughput forecast and the actual shrinkage experienced on PG&E's system. Table 8-5 of Exhibit 1 contains PG&E's illustrative 2004 shrinkage allowances, which are based on PG&E's forecasted demand, and recent actual transmission and distribution LUAF and GDU. PG&E proposes that these shrinkage allowances be updated through its proposed compliance filing using the actual LUAF and GDU figures available in December 2003.

PG&E also proposes that it be allowed to make a separate advice letter filing at other times of the year to adjust shrinkage allowances in order to better match the actual shrinkage experienced on the system.

PG&E proposes that the BCAP continue to be the proceeding in which to determine the pipeline shrinkage calculation methodology, including the proportion of LUAF and GDU that are assigned to transmission and distribution shrinkage.

b. Storage Shrinkage Proposal

PG&E proposes that a new in-kind storage shrinkage allowance be applied to all scheduled storage injection volumes. This allowance will collect from storage customers, the cost of GDU and LUAF that is associated with PG&E's gas storage operations. PG&E also proposes to continue the recovery of a portion of the cost of electricity used by PG&E's gas department in operating its storage field in storage rates, as done in the Gas Accord. PG&E's gas storage shrinkage costs are currently recovered through the transportation in-kind shrinkage allowances. If PG&E's proposal is adopted, the gas storage shrinkage costs will be excluded from the transmission and distribution in-kind shrinkage allowances.

The in-kind shrinkage quantity for storage would be calculated by dividing the total storage-related GDU and LUAF by the forecast annual storage-cycle quantity. The resulting in-kind shrinkage percentage would be taken in-kind from the storage injection nominations to determine the net-injection quantity that will be credited to that storage customer's inventory. PG&E calculates the in-kind shrinkage allowance for storage injections is 0.7% of the injection quantity.

PG&E has proposed that its balancing service be allocated 4 Bcf of the total storage cycle inventory. The storage shrinkage quantity allocated to the 4 Bcf for balancing service will be reallocated back to the transmission and distribution shrinkage quantities as additional GDU.

PG&E proposes that the storage shrinkage allowance implementation be scheduled to coincide with the April 1, 2004 start of the storage season. PG&E also proposes that annual updates to the storage shrinkage allowance, if needed, be done through a compliance filing to be effective at the beginning of each storage season.

7. Noncompliance Charge Proposal

PG&E points out that the gas price volatility experienced during the 2000-2001 winter season provided evidence that fixed noncompliance charges that are not indexed to the market price of gas, may be an ineffective tool to achieve the desired results when an OFO or EFO is called. A situation could occur where a balancing entity may find it more economic to incur a noncompliance charge than to comply with a flow order or curtailment.

PG&E proposes that most noncompliance charges be modified to include a cost of gas component. Table 8-6 at page 8-37 of Exhibit 1 shows the schedule of proposed noncompliance charges for core and noncore. Table 8-6 lists three gas indexes which the noncompliance charges use. The three indexes are the Monthly Citygate Index, the Daily Citygate Index, and the Lowest Citygate Index. These three indexes are described at pages 8-35 and 8-36 of Exhibit 1.

PG&E proposes that all of the noncompliance charges shown on Table 8-6 of Exhibit 1 continue to be recorded into the BCA. The balance in the BCA would then allocated as determined in the BCAP.

8. Anonymous Trading Platform Proposal

In the Gas OII Settlement Agreement, which was approved in D.00-05-049, the parties agreed to a third party electronic trading platform to facilitate anonymous trading of imbalances and backbone capacity contracts. D.00-05-049 also authorized an implementation cost of $700,000 for these services, which was debited to the BCA. (*See* D.00-05-049, p. 29, FOF 9.)

PG&E had extensive discussions with the selected third party service provider to provide the trading platform. However, the provider decided not to go forward with the project due to a number of issues that arose, and a contract with PG&E was never finalized. Although PG&E held talks with other potential vendors, none of them were willing to develop an anonymous trading system that met PG&E's current trading requirements.

PG&E notified customers and the settlement parties in September 2000 that the selected vendor would not be developing the trading platform, and that the services would be delayed. PG&E also investigated building its own trading platform, but the costs associated with its development and the relatively small volume of transactions make the trading platform too expensive. None of the customers or settlement parties have inquired about the status of the trading platform or requested that these services be implemented in an alternative manner.

PG&E proposes that the third party electronic trading platform and services be eliminated. PG&E proposes to credit back $656,000 to the BCA, which is the unspent portion of the $700,000 that was approved in D.00-05-049 for this project.

PG&E notes that the elimination of this anonymous trading platform and services will not impact the operations of other existing trading vehicles, even though those trading vehicles require that each party identify its trading partner.

B. Positions of the Parties

1. CCC/Calpine

a. Curtailment Proposal

CCC/Calpine agree with CMTA that PG&E's curtailment proposal should be rejected because it is contrary to the structure of the Gas Accord, would absolve PG&E of the responsibility of wisely managing its transportation, storage capacity and gas procurement, and would provide PG&E with an incentive to curtail. As CMTA points out, curtailment serves as a cheap and effective means of using noncore gas supplies to serve core customers without having to pay a diversion penalty directly to noncore customers.

Should the Commission be leaning toward adopting PG&E's curtailment proposal, CCC/Calpine urge that the Commission postpone making a final decision until workshops are held with customers to further consider the proposal's justifications and potential impact. As NCGC points out, workshops are needed because PG&E's proposal does not explain various critical details about how the proposed pro rata curtailment would be administered, including which winter season would be used to calculate a benchmark allowed burn level for customers prior to each winter season. Customers cannot ascertain the impact of PG&E's proposal unless and until PG&E provides the important details of its proposal. PG&E has expressed a willingness to work out implementation details in a workshop.

Should the Commission decide to hold workshops regarding the viability of PG&E's curtailment proposal, CCC/Calpine urge the Commission to require

PG&E to explain why the proposals of the Indicated Producers to modify PG&E's curtailment proposal should not be adopted.

b. Daily Imbalance Proposal

PG&E proposes adding a daily imbalance tolerance limit to its monthly balancing service option in order to discourage the large daily imbalances that are occasionally created by a few balancing entities on the system. CCC/Calpine assert that PG&E has not justified this proposal. PG&E has not presented evidence that it has tried less drastic measures to reduce customer specific OFOs on its system. CCC/Calpine agree with Duke that PG&E should be required to attempt less punitive and more narrowly tailored measures before resorting to a daily imbalance penalty that could result in non-offending shippers being penalized.

2. CMTA

CMTA opposes PG&E's proposal to replace the diversion process with PG&E's proposed curtailment mechanism. CMTA contends that PG&E's proposal is contrary to the structure of the Gas Accord, that it would free PG&E from the responsibility of wisely managing its transportation and storage capacity and gas procurement, and would provide PG&E with an incentive to curtail. CMTA asserts that if PG&E's Core Procurement Department fails to buy enough gas to meet its core needs, the curtailment procedure provides a cheap and effective means of using noncore gas supplies to serve core customers without having to pay a diversion penalty directly to noncore customers.

PG&E's curtailment proposal would not compensate customers for curtailed volumes, instead, it would allow the customer to control the disposition of its gas supply. CMTA contends that because the amount of curtailed supplies available to sell may be small and the notice likely to be short, it is unlikely that the curtailed customer could sell the curtailed supply at a fair price. CMTA asserts that a curtailment would create a buyer's market of noncore supply for core suppliers and buyers. Whereas under the current diversion process, PG&E pays customers if their gas is diverted. PG&E's curtailment proposal would eliminate any such compensation.

PG&E has suggested that curtailed customers could run a positive imbalance to offset future use. This would allow PG&E to receive the high volume of the customer's positive imbalance on that day, and return the gas on a future day when gas prices are likely to be lower. CMTA contends that because the effect of PG&E's proposal is to lower the cost of obtaining core gas supplies during peak demand days, PG&E's proposal could provide it with an incentive to curtail more frequently.

CMTA also points out that because the curtailed customer could be forced to run a positive imbalance on a day when prices are high, and have PG&E return the gas at a price that is low, that this could be a windfall to core customers, because they would receive the higher valued gas and return lower valued gas.

Under the current diversion process, PG&E's Core Procurement Department is required to maximize its efforts before resorting to diversion of noncore customers. Although such efforts have not been included in PG&E's curtailment proposal, PG&E witness Johnson indicated that he expected that a similar requirement would be added. In the event the Commission adopts PG&E's curtailment proposal, CMTA recommends that such a requirement be added.

In addition, if the curtailment proposal is adopted, CMTA recommends that the proposal be modified to ensure that noncore customers are fairly compensated for their curtailed supplies that are delivered into the system, and that the incentives for PG&E to curtail be eliminated. CMTA recommends that noncore customers be compensated at a rate equal to the daily gas index price plus $10 per Dth. Such compensation would ensure that curtailments are a last-resort source of core supplies. Also, the curtailment process should allow noncore customers to trade curtailment levels among themselves, provided that the aggregate amount of curtailments is not reduced.

PG&E opposes the proposal for a rate equal to the daily gas index price plus $10 per Dth because it would be a windfall to curtailed noncore customers. CMTA asserts that the $10 per Dth payment would not be a windfall, but rather would represent compensation for noncore customers who have lost the benefit of their contracted for supplies, and who may be forced to shut down their manufacturing operations. Nor would it be sufficient compensation to pay curtailed customers the amount of the daily price index.

CCC/Calpine witness Beach recommended allowing noncore customers in any curtailment process to trade curtailment levels among themselves, provided that, the aggregate amount of curtailments is not reduced. PG&E stated it is willing to explore such an idea in a workshop setting, and CMTA would welcome such an opportunity. If the Commission adopts a curtailment process for noncore customers, the process should include this modification.

PG&E asserts that its Core Procurement Department has an incentive to have gas under contract because the failure to deliver adequate supply would cause the Core Procurement Department to face a noncompliance charge of market price plus $60. CMTA asserts that $60 EFO charge comes too late in the process to act as an incentive to avoid curtailment, and can easily be mitigated depending on the subsequent allocation of EFO charge revenues.

CMTA also asserts that PG&E's curtailment proposal would cut firm customers equally with as-available customers, which is unfair to firm customers and inconsistent with the Gas Accord structure. CMTA contends that the pro-rata curtailment would not treat firm and as-available equally because firm and as-available customers do not, and should not, have equal expectations of deliverability. That is, customers take firm service for its greater assurance of delivery, and as-available customers trade firm delivery for a lower price. PG&E's proposal undermines these preferences by curtailing firm customers equally with as-available customers. This is less fair than the current diversion process, which allocates a diversion so that as-available customers are diverted before firm customers.

One of PG&E's concern over the current diversion process is about the efficiency of communications under the diversion process. CMTA points out, however, that experience shows that marketers and end-use customers have regular, well-developed lines of communications and typically communicate on a daily basis.

3. California Natural Gas Producers Association

The California Natural Gas Producers Association (CNGPA) is opposed to PG&E's proposal regarding the gas balancing rules. CNGPA asserts that California gas production provides unique flexibility to the PG&E system over other sources of PG&E supply. This flexibility is due in part to the proximity of California gas to the PG&E system and the markets that actually consume the gas. CNGPA asserts that California gas aids in the physical management of PG&E's system by following PG&E's load patterns.

CNGPA points out that according to the 2003 California Gas Report, California in-state gas production accounts for only 7.4% (or 147 MMcfd) of

PG&E's total pipeline system supply of 1987 MMcfd. PG&E, however, alleges that California production is responsible for large gas imbalances on the entire PG&E system during OFOs. PG&E also accuses CBPA managers of potential profit taking by marketing nomination flexibility during OFO periods.

PG&E proposes that California gas production imbalances, managed through a CBPA, be subject to the same OFO requirements and noncompliance charges applicable to all other balancing entities. CNGPA is opposed to this proposal, and contends that PG&E's proposal is a significant threat to California gas production.

CNGPA points out that on an average day, PG&E's customers consume nearly 2000 MMcf of gas, with less than 10% derived from California in-state supply. The remaining 1800 MMcfd or more enters the state at the border delivery points. While the pipeline companies and PG&E target delivery quantities into PG&E, based on scheduling by shippers and marketers, physical imbalances always exist at those border delivery points. The existence of these imbalances is primarily due to the complex nature of large-volume deliveries and the cyclical customer loads on the PG&E system. CNGPA asserts that this large scale variance should be investigated by PG&E and the Commission, rather than unfairly discriminating against California production that represents such a small part of the customer requirements on the PG&E network.

CNGPA points out that CPBAs do not have access to real-time operating and balancing data on the PG&E system, like PG&E's other gas supply sources and even their end-use customers. The data that PG&E provides to CPBAs is received by the 15th day of the month following the month that the gas was produced and delivered into the PG&E system. CNGPA asserts that this lack of data makes it virtually impossible to adequately balance the physical flows of gas with nomination commitments. Although electronic flow measurement has been installed by PG&E at the delivery points of California production, the CPBAs have been denied remote access to this EFM data. Without accurate data, it is impossible for PG&E and the CPBA to talk and make operational adjustments as needed to maintain the balance between nominations and actual deliveries. CNGPA asserts that California gas should not be singled out as the prime cause for OFO imbalances when 92.6% of PG&E's supply comes from out of the state.

CNGPA asserts that PG&E's proposal contains elements that are significantly detrimental to California produced natural gas, particularly as it sets forth to establish strict CPBA balancing guidelines. Since § 785 (a) mandates that the Commission shall encourage the increased production of gas in this state, PG&E's proposal will discourage any increase of in-state production, and have a negative impact on remaining gas reserves. Also, § 785.2 provides that the Commission is to investigate, as part of the rate proceeding for any gas corporation, impediments to the in-state production or storage of natural gas. CNGPA believes that PG&E's proposal would be adverse to the interest of gas customers by potentially forcing Californians to rely more on natural gas from outside of the state, and removing tax revenues derived from California production that presently flow to the state and local governments. The Commission should uphold state law, and remove PG&E's proposed balancing guidelines from the proposal.

To accommodate the cycles of customer demand on the PG&E pipeline network, PG&E regularly changes flow patterns and raises and lowers pipeline pressures. As a result, California production flows may be physically curtailed due to higher pipeline pressures or altered flow patterns on the PG&E system. Oftentimes CPBAs only become aware of these inadvertent flow reductions after the fact, providing no time for changing downstream market nominations. This results in an imbalance between the nominated and actual flows that was actually caused by PG&E. Currently, the CPBA balancing partially contemplates these imbalances by allowing the CPBA to resolve the imbalance within the producing month or during the month following. Under PG&E's proposal, this flexibility will be eliminated forcing the CPBA to carry imbalances into a potential cash-out with PG&E at a future date. PG&E's cash-out mechanism pays only 50% of the value of over-deliveries, and charges 150% if PG&E provides gas to balance deficient deliveries by the producer.

CNGPA contends that due to the unreliability associated with PG&E curtailment of flows from time to time, it is difficult for producers and CPBAs to commit to reliable monthly markets. The current balancing structure provides some flexibility to manage fluctuations on PG&E's system. With the adoption of PG&E's proposed CPBA balancing changes, this situation would be exacerbated, forcing California producers into daily pricing for their gas production. CNGPA asserts that daily pricing is often volatile, and unsettling to the producer and mineral interest owner, potentially removing the incentive to drill new wells to meet the growing market demand.

4. Coalinga

Coalinga contends that PG&E has failed to establish that PG&E's proposals for a daily imbalance penalty, and to increase the storage allocation to balancing, are needed at the present time. Coalinga recommends that the Commission reject these proposals.

5. DGS

PG&E proposes various modifications to its rules relating to management of the supply shortfall and capacity constraints. One modification is to replace the existing diversion process with a curtailment process. PG&E proposes that when a curtailment occurs, that the required load reduction be shared across all noncore end-use customers on a pro-rata basis. DGS supports PG&E's proposal, and recommends that the Commission make the necessary findings in order to confirm that this priority system for curtailment complies with § 2779 and following. [39]

6. Duke

PG&E proposes five different measures to manage system imbalances and to reduce the number of OFOs, the procedure adopted in the Gas Accord to maintain the overall system balance. Among the five measures is a proposal to implement a new daily balancing requirement. This daily balancing requirement would require customers to stay within a limit of plus or minus 35% of daily usage, or plus or minus 30,000 Dth, whichever is larger. Customers who fall outside of this permitted band would be subject to a charge of 25 cents/Dth.

Duke recommends that the Commission reject the proposed daily balancing requirement. One reason for rejecting the imbalance proposal is that it may penalize customers who do not contribute to system imbalances. Under PG&E's proposal, the daily balancing penalties would be imposed whenever an individual customer's imbalance exceeded the specified range, even is there is no system problem that day. Duke contends that a proposal that imposes penalties when no harm results does not make sense and should be rejected.

Another reason for rejecting PG&E's daily balancing proposal is because of the harmful effect on electric generation customers. Duke points out that electric

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[39] Unless otherwise stated, all code section references are to the Public Utilities Code.

generators are among the largest of PG&E's gas customers. Electric generators are subject to highly variable electricity demand, and their gas consumption and transportation scheduling cannot be predicted with much confidence. Also, electric generators are subject to orders from the CAISO to increase or decrease generation. For these electric generators, the proposed daily balancing penalty will not serve to influence behavior, instead, it will only function as an unnecessary penalty serving no useful purpose.

Duke believes that before a daily balancing requirement is imposed, that PG&E's four other proposals to improve the ability to balance the system should be given a chance to see effective they are before imposing the strict daily balancing requirement, which subjects customers to harsh penalties even when the overall system is in balance.

7. Indicated Producers

One of PG&E's proposals is to replace the existing involuntary diversion procedures with a pro-rata curtailment of all noncore customers. The Indicated Producers point out that service level distinctions have played a role in PG&E's transportation services for over ten years. In D.91-11-025, the Commission eliminated the curtailment priority scheme based on end-use, and replaced it with a method based on a customer's decision to purchase firm or interruptible service. The same principles were continued in D.97-08-055, and incorporated into the Gas Accord. The firm and interruptible service levels were integrated into PG&E's procedures for involuntary diversions. Involuntary diversions recognize that the utility should provide the greatest protection to those customers who have expressly placed a value on service reliability through the acquisition of firm service.

The Indicated Producers state that PG&E's proposal would eliminate the material benefit of choosing firm transportation service. They question what the benefits of firm service will be, if there is no higher level of reliability during times of constraint or supply curtailment. The proposed pro rata curtailment would remove customer choice and service level distinctions by determining that all customers should be treated equally.

If the Commission adopts the proposal for a curtailment process, the Indicated Producers believe that it should be modified to reflect several features of the current diversion process. First, the curtailment process should distinguish among service types, with interruptible service curtailed before firm service. Second, the curtailment procedures should retain the same kind of obligation found in Gas Rule 14 that market remedies be sought before curtailment of noncore customers begin. And third, that a curtailment penalty should apply to prevent the use of a curtailment by PG&E's Core Procurement Department to reduce core costs when prices are high, and to recognize the impact of curtailments on noncore customer operations.

In addition, if the curtailment proposal is adopted, the curtailment procedures should also require the following: (1) that PG&E seek to purchase additional gas supplies at prices which are regarded as reasonable and prudent; (2) that PG&E curtail deliveries to any customer in excess of volumes allowed under contract; (3) that PG&E make a public service announcement for voluntary actions by suppliers and end-use customers; and (4) that PG&E ask customers to voluntarily reduce use and/or increase deliveries, depending on the nature of the situation which results in an EFO. Unless these market remedies are made part of PG&E's noncore curtailment procedures, the Indicated Producers contend that the curtailment procedure would reduce the incentives of CPGs to pursue market remedies that could mitigate the need for a curtailment.

Under the existing Gas Rule 14, if an involuntary diversion occurs, customers who use more gas during an involuntary diversion than their post-diverted supply will be assessed a $50 per Dth diversion usage charge, and a $50 per Dth EFO noncompliance charge, for a total involuntary diversion charge of $100 per Dth. Firm transmission customers whose gas supply is involuntarily diverted receive a $50 per Dth diversion credit. As-available transmission customers receive a diversion credit based on the market price for the gas on the day the diversion occurred.

Under PG&E's proposal, there is no gas supply compensation. Instead, the CPGs are required to buy supply to meet their customer demand or be subject to an EFO noncompliance charge equal to $60 per Dth, plus the daily citygate indexed price of gas. PG&E believes that this will act as an incentive for the CPGs to buy the gas at the market price from those marketers and noncore end-users who have been curtailed. The Indicated Producers, however, believe that noncore customers are worse off than under the existing involuntary diversion rules because they are likely to receive less under PG&E's proposal.

The Indicated Producers recommend that an appropriate curtailment penalty apply to PG&E's proposal to prevent the use of curtailment by PG&E's Core Procurement Group as an economic tool to reduce core costs when prices are high, and to compensate noncore customers for the impact of a curtailment event on their operations. PG&E's CPG should be required to purchase from noncore end-use customers, any positive imbalances that noncore customers run during a curtailment period. This would compensate a noncore customer for any supplies above the level of its curtailed demand that are still delivered into the system, which help meets core needs. The Indicated Producers support the CCC's proposal that the price for these supplies be the daily gas index price plus $10 per Dth, in order to ensure that curtailments are a last-resort source of core supplies.

The Indicated Producers also recommend that if a curtailment process is approved by the Commission, a workshop or working group should be required to develop specific procedures for implementing curtailments, and that such procedures be approved by the Commission.

PG&E has also proposed to modify the existing balancing framework to reduce the number of OFOs and EFOs. The proposed modifications include assigning additional storage capacity to balancing service, and adding a wide daily imbalance limit to the monthly balancing service requirements. The new imbalance limit would be plus or minus 35% of daily usage or plus or minus 30,000 Dth, whichever is larger.

The Indicated Producers assert that PG&E has failed to substantiate that either of these modifications are needed, or that these measures will actually reduce OFOs. The Indicated Producers point out that many changes have occurred in the market since PG&E's analysis of the data was first done. By dedicating more storage to balancing, the Indicated Producers contend that this will increase costs to customers and reduce PG&E's risk of revenue under-recovery from at-risk storage. If the Commission adopts PG&E's proposal to add more storage capacity to balancing, it should do so on a provisional basis. If the OFO reduction does not occur as anticipated, the additional storage reservation should be returned to the at-risk storage services.

The objective behind PG&E's proposal to impose a 35% daily imbalance limit is to reduce imbalances and the number of OFOs. The Indicated Producers do not believe that this proposal has been carefully studied, and is likely to increase the cost to noncore customers. The Indicated Producers recommend that PG&E's balancing proposal be rejected, or modified to allow the increased storage reservation to be implemented on a provisional basis, but that it be returned to existing levels if it fails to produce the anticipated reduction in OFOs. They also recommend that PG&E's proposal for a 35% daily imbalance limit be deferred until PG&E determines the effectiveness of the increased storage reservation.

8. LGS

PG&E justifies the proposed increase of storage capacity for balancing by referring to the occurrence of OFOs and a March 7, 2000 storage study, which PG&E neither included nor excerpted in its testimony. LGS is concerned that PG&E's proposal will allow PG&E to transfer its currently at-risk storage in a fashion that ignores existing storage competition and that will ultimately be anti-competitive.

PG&E's proposal was based on customer feedback. According to PG&E witness Johnson, customers expressed support for actions to limit the number of OFOs, including additional storage capacity. Johnson, however, kept no written record of this, and no specific customers were identified. Also, the conversations with customers about the OFO issues which led to this proposal, concern how the system operates today, not how it would operate if the proposals are adopted. LGS contends that PG&E's assertions regarding customer feedback are unpersuasive, given the lack of proof of the existence, nature, and volume of such feedback, and the identity of the customers providing such feedback.

LGS asserts that PG&E has provided no comprehensive analysis in the form of a cost-benefit study or any other study that suggests the Commission should allow PG&E-owned storage to be reassigned from market storage to balancing.

PG&E's second basis for the proposal is recent experience. However, PG&E's testimony provided no details regarding this recent experience. During cross-examination, PG&E witness Johnson admitted that recent experience references OFOs occurring after the March 2000 storage study. (6 RT 571) PG&E has not identified no other recent experiences supporting its proposal to dramatically increase storage dedicated to balancing.

The other basis for PG&E's proposal is Figure 8-1 on page 8-11 of Exhibit 1. Through cross-examination, it was learned that Figure 8-1 had its origins in an update of the March 2000 storage study. (6 RT 552-553; Ex. 18.) But the March 2000 study was not provided as part of PG&E's testimony. Also, Figure 8-1 is a prediction looking back at what happened, and what PG&E thinks would have happened with respect to OFOs with additional storage injection capability. (6 RT 550, 571-572.) The differing amounts of injection and withdrawal reflected in Exhibit 18 are just assumptions made for the purpose of the study. (6 RT 572-573.)

LGS also contends that PG&E has not considered whether adopting the other measures proposed by PG&E would meet the goal of reducing the number of OFOs. LGS witness Dill testified that it is not clear that this increased storage allocation is really necessary. Dill noted that PG&E proposes to make two other adjustments to make customers more responsible for their own balancing requirements: establishing a daily imbalance limit for the monthly balancing option, and changing the disposition of monthly imbalances after the imbalance trading period. PG&E also proposes to require California production to comply with the same OFO obligations as other balancing entities.

LGS suggests that before adding more storage for balancing, it should be determined whether these three other measures will meet the goal of reducing the number of OFOs. LGS asserts that these three proposals create the imbalances that are a major cause of the OFOs. This is supported by the OFO reports attached as Appendix 8-A to PG&E's rebuttal testimony where PG&E observes that the ineffectiveness of customer-specific OFOs has led PG&E to call system-wide OFOs during high-inventory condition, even when the customer-specific criteria were met. PG&E also references the negative system impact of California production imbalances. LGS asserts that the impact of PG&E's balancing proposals should be measured first, before adding storage capacity.

LGS also asserts that PG&E presented neither evidence nor analysis concerning the positive effect of PG&E's other proposals. Although PG&E contends that these proposals will work to diminish the OFOs, PG&E has made no showing as to whether those proposals would achieve a lower incidence of OFOs without also resorting to additional storage capacity for balancing.

LGS witness Dill raised concerns about the lack of detailed evidence to support PG&E's proposals, and that it is an effort by PG&E to market its storage in a non-competitive manner. Even if an increase in storage capacity is justified for balancing purposes, LGS states it can probably be met more cost effectively by LGS, Wild Goose, a combination of both, or through some other sort of portfolio approach.

LGS witness Dill also stated that LGS does not believe that balancing entities should have any obligation to use PG&E's balancing service. Such entities should be free to seek competitive provisioning of such storage service from all storage providers. Also, rolling in additional balancing resources creates costs for all PG&E customers whether they need those services or not.

LGS was not alone in criticizing PG&E's proposal. Wild Goose's witness stated that PG&E's proposal could potentially disadvantage PG&E ratepayers. The witness also expressed concern that, without further analysis, the possibility exists that PG&E is merely seeking a means by which to recover the costs of its excess storage without subjecting it to market forces. He also suggested that if the need for additional balancing could be demonstrated, it should be put out to bid.

The Commission should disapprove PG&E's proposal to add storage. If PG&E believes that additional storage is needed, PG&E should present a proper and detailed cost benefit analysis to the Commission.

In the event the Commission decides that a need exists to add storage to the balancing function, the Commission should not automatically approve PG&E as the source of such storage. There are competitive storage providers in PG&E's service area, and it is possible that they could lower the cost of the additional storage that is assigned to the balancing function. Thus, if the Commission determines that more storage would assist in balancing PG&E's system, it should also require PG&E to seek bids to provide that storage.

PG&E has not provided any technical explanation as to why third party storage cannot be used to balance PG&E's system. PG&E's witness agreed that storage can be used to help keep the system in balance. (6 RT 580.) As Wild Goose observed in its opening brief, if storage is connected to the pipeline system, it can assist in balancing regardless of who owns it.

LGS has not taken a position on whether PG&E's current diversion system to address scarce gas supply should be replaced with a curtailment system as proposed by PG&E. However, if PG&E's curtailment proposal is adopted, LGS agrees with Wild Goose that customers who stored gas should be allowed to withdraw the gas in the event of curtailment. As Wild Goose points out, not allowing noncore customers with stored gas to access that gas during curtailments will provide a disincentive to store gas. That is, why should a customer buy gas and pay to store it, when you are not allowed to withdraw and maintain ownership of it precisely when you need it. If the Commission approves PG&E's curtailment proposal, it should require PG&E to allow customers with gas in storage to withdraw that gas during times of curtailment.

9. Mirants

PG&E asserts that the daily imbalance limit is needed to discourage extremely large daily imbalances that occasionally are created by a few balancing entities on its system. PG&E proposes a limit of the larger of either plus or minus 35% of daily usage, or plus or minus 30,000 Dth, with an excess daily imbalance charge of $0.25 per Dth proposed as an incentive to stay within the limit. According to PG&E, its proposal would affect only about 2% of daily imbalances, but would be adequate to eliminate very large imbalances that disrupt system operations.

Mirant appreciates the problems such imbalances can impose on system operations, but remains troubled by PG&E's proposal. Mirant states that Wild Goose is probably correct that given the volatility of gas prices, PG&E's proposed penalty amount will be insufficient to affect shipper's behavior very much. Duke and NCGC are correct that PG&E's proposal would penalize individual customers' imbalances regardless of their system impacts. Mirant contends that instead of bringing the gas system into balance, PG&E's plan would impose cost burdens on some customers, regardless of whether their particular imbalances exacerbated or alleviated the imbalance. Increasing the level or incidence of penalties, as Wild Goose suggests, might make the plan more effective, but it would not target the pain any more efficiently on those imbalances that may impair system operations.

Mirant also notes that PG&E said that if its proposal proves ineffective, that the issue can be revisited using the OFO Forum process. Mirant contends that this comment validates the suggestions of Duke and the Indicated Producers that the Commission should see how effective the other PG&E proposals are before imposing such a penalty. As NCGC stated, a more focused OFO process offers a fairer and probably more effective way of targeting those who cause large daily imbalances on PG&E's system.

Mirant opposes the imposition of any daily imbalance penalty scheme at this time.

10. NCGC

a. Additional Storage Capacity

PG&E proposes to increase the amount of storage capacity that it would assign to provide system-balancing services by reassigning existing capacity to the balancing function. PG&E proposes to increase the amount of assigned injection capacity by 25 MMcf/d to 75 MMcf/d. PG&E also proposes to increase assigned withdrawal capacity to 75 MMcf/d, and to increase assigned inventory capacity to 4 Bcf.

The total cost for system balancing service would be $10.523 million. Of this amount $4.7 million would be for 75 MMcf/d of injection capacity,

$0.7 million for 4 Bcf of inventory capacity, and $5.1 million for 75 MMcf/d of withdrawal capacity.

NCGC supports PG&E's proposed increase in storage capacity that is to be assigned for system balancing. PG&E's March 7, 2000 study concluded that allocating additional storage capacity to balancing may result in a proportionate reduction in the frequency of OFOs. OFOs affect all customers, including PG&E's Core Procurement Department. In addition, reassigning existing capacity to expand balancing service is less costly than building new storage capacity.

NCGC recommends that the Commission go beyond PG&E's proposal and expand the amount of capacity assigned to balancing by adding an additional 25 MMcf/d of injection capacity, resulting in 100 MMcf/d of injection capacity. The additional injection capacity could reduce the number of high OFOs by 34%. If injection capacity were increased to 100 MMcf/d, high OFOs could be reduced from 79 to 52 utilizing the April 2000 to October 2002 data that PG&E used.

PG&E's proposed addition of 25 Mdth/d of injection capacity to the balancing function adds $1.56 million to the cost of balancing service. Increasing the amount of injection capacity by another 25 MMcf/d to a total of 100 MMcf/d would add another $1.56 million.

The only parties who object to PG&E's proposal for increasing balancing capacity are the Indicated Producers, and the two third party storage providers. The Indicated Producers argue that the data upon which PG&E relies are not persuasive and are stale. NCGC points out that although the March 2000 study was entered into the record, PG&E conducted a new study to predict the number of OFOs that would have been experienced during April 2000 through

October 2002 if increased storage injection and withdrawal capacity had been available for balancing service. This was presented in Figure 8-1 of Ex. 1 at 8-11.

LGS and Wild Goose contend that instead of using PG&E's own storage capacity, that PG&E should acquire additional storage capacity for the balancing function from them. NCGC points out that neither LGS nor Wild Goose have committed that they would make storage capacity available for the balancing function at a cost that would meet or beat the revenue requirement associated with the depreciated installed capacity that PG&E would add to the balancing function. Also, as PG&E witness Johnson pointed out, PG&E needs to have direct control over the storage capacity so that pipeline operators have the ability to make numerous adjustments throughout the day to ensure safe and reliable operations. Also, if LGS or Wild Goose provide the storage capacity, the opportunity to add storage capacity to the balancing function at depreciated embedded cost may be lost to PG&E customers for a long time. If this assignment of existing storage capacity to the balancing function is not seized, the storage capacity could be sold for an undetermined number of years.

NGC also contends that all customers, core and noncore, benefit from expanding PG&E's capacity to provide balancing service and to avoid OFOs. Also, the cost of the expanded load balancing service would be shared among all customers, insofar as load balancing storage costs are bundled in backbone transmission rates. In light of PG&E's study of the benefits of expanding the amount of capacity allocated to the load balancing function, and in light of the broad sharing of both the benefits and the costs of the expansion, NCGC recommends that the Commission approve an expansion as proposed by NCGC.

b. Daily Imbalance Limit

PG&E proposes to impose a new daily imbalance limit that would be plus or minus 35% of daily usage or plus or minus 30,000 dth, whichever is larger. PG&E proposes to charge a $0.25/dth excess imbalance charge on all daily imbalances that exceed the proposed daily imbalance limit.

NCGC opposes PG&E's proposal to impose a daily imbalance limit under ordinary pipeline operating conditions when OFOs have not been declared. PG&E has not shown that this is necessary. PG&E witness Johnson testified that a study of daily imbalances incurred by all balancing entity groups during 2000 and 2001 revealed that only two percent of daily imbalances exceeded the proposed daily limit. NCGC contends that the daily imbalances under non-OFO conditions does not warrant imposing a penalty scheme on all customers at all times, even when the system as a whole is in balance.

As an alternative to imposing daily balancing limits, NCGC witness Pretto proposes that PG&E explore improvements to the OFO process that would bring more focused attention on those who are the cause of large daily customer imbalances. NCGC contends that this approach would relieve the vast majority of transportation customers from potentially suffering the prospect of daily imbalance charges that are intended to address an infrequent, intermittent problem that is not of their making.

c. Imbalance Charge

Currently, customers are required to balance their monthly supply and demand within a 5% tolerance band. After the end of a month, customers are allowed to trade monthly imbalances with other customers or into a storage account. Customers are permitted to carry imbalances between zero and 5% into the next month. At the end of the trading period, PG&E uses a cash-out mechanism to purchase positive customer imbalances outside of the 5% monthly tolerance band. PG&E uses the same mechanism to sell gas to customers that have negative imbalances outside the 5% tolerance band.

PG&E proposes to replace the current cash-out process with an imbalance charge for monthly imbalances in excess of the 5% tolerance band. A customer's entire monthly gas supply imbalance, including any quantity beyond the five percent monthly tolerance limit, would be carried forward to the subsequent month.

NCGC supports the continuation of the existing cash-out process. NCGC contends that PG&E has failed to show a need to eliminate the cash-out process. Although PG&E contends that the economic impact of cashing out monthly imbalances beyond the 5% tolerance flows to customers, the contrary is true. NCGC points out that when PG&E buys or sells gas to "cash out" imbalances beyond the 5% tolerance, the costs are allocated to the BCA, which is allocated to all customers. The revenues are also allocated to the BCA, and revenues outstrip costs. For the period March 1998 through December 2001, PG&E received revenues of $14.7 million for cash-out sales and incurred expenses of $2.2 million for cash-out purchases.

NCGC asserts that it should be expected that PG&E makes money on cash-outs. Under Schedule G-BAL, the cash-out price paid to customers for positive imbalance gas is 75% of the Weighted Over Delivery (WOD) index, an index of the lowest prices experienced during the month in which the imbalance occurred. The cash-out price charged for gas sold to customers to cash-out negative imbalances over 5% is 125% of the Weighted Under Delivery (WUD) index, an index that reflects the highest prices experienced during the month in which the imbalance occurred. Thus, a customer that remains out of balance so that a cash-out occurs has his imbalance bought or sold by PG&E at a price that is disadvantageous for the customer and advantageous for PG&E.

NCGC contends that the cash-out prices in Schedule G-BAL provide a marked incentive for a customer to stay within the 5% monthly imbalance tolerance and not allow a cash-out to occur. The current cash-out mechanism sufficiently penalizes an out-of-balance customer without imposing the further penalty of leaving imbalance gas in the hands of the customer for disposition the following month.

d. Curtailment Process

PG&E proposes to replace the involuntary diversion process that was developed in the Gas Accord with a curtailment process. When noncore demand must be reduced to ensure continuous service to core customers, the curtailment would be pro rata across all noncore customers. PG&E states that the existing diversion process is slow and cumbersome, and because the process applies to backbone transportation shippers, it is difficult to prioritize the diversion supplies down to specific noncore customers.

PG&E's proposed curtailment process would be applied on either a system wide basis or on a particular local transmission system, as necessary. The curtailments to noncore customers would be pro rata, as opposed to a rotating curtailment block system, so that all noncore customers have some allowed gas usage.

NCGC does not believe that PG&E has adequately explained the details on how the pro rata curtailment process would work. In order to resolve these implementation issues, NCGC believes that a workshop should be held to address the details of PG&E's curtailment process. PG&E agrees that a workshop is appropriate. NCGC recommends that PG&E's proposal to adopt a pro rata curtailment scheme be approved, but that a workshop be convened to resolve the various details of how curtailments would work.

11. ORA

ORA is opposed to PG&E's proposed $60 per Dth penalty for core customers, and that customers pay the market price and purchase supply from noncore customers with excess capacity. PG&E's rationale is that this proposed penalty would provide an incentive for core customers to properly forecast their demand based on PG&E's proposed 1-in-10 year winter reliability standard, and that it will provide an incentive for noncore customers to sell, at true market prices, their excess capacity to core customers.

ORA does not believe that the proposed penalty is justified, and questions PG&E's rationale. ORA contends that PG&E has not made any showing that the core class has habitually underestimated its capacity needs. PG&E's own witness testified that he believes that CPGs would endeavor to meet their demand at any level, even if it is above the proposed 1-in-10 year winter reliability standard. ORA does not believe that the imposition of penalties on core customers for underestimating their needs will persuade noncore customers to sell, at true market prices, their excess capacity to the core class. Instead, noncore customers might withhold their excess capacity in order to drive up market prices, and core might have to pay higher than market prices in order to avoid paying PG&E's $60 per decatherm penalty.

ORA contends that because there is a correlation between PG&E's winter reliability standard and the proposed increased core penalties, if the Commission rejects PG&E's proposed winter reliability standard, PG&E's proposed OFO or EFO penalties should be rejected as well.

12. Palo Alto

Due to the procedural schedule and constraints on the parties' resources, Palo Alto does not believe that PG&E's proposals have been adequately reviewed. These proposals include replacing the diversion process with a curtailment process, increasing the amount of storage capacity balancing, establishing the daily imbalance limit, and requiring CPGs to balance based on the 7:15 a.m. forecast on the day of flow.

Palo Alto also contends that PG&E has failed to establish that these proposed changes are needed at the present time.

13. SPURR/ABAG

The School Project for Utility Rate Reduction and the Association of Bay Area Governments Publicly Owned Energy Resources (SPURR/ABAG) agree with ORA that PG&E has provided no justification for a penalty equal to $60 per Dth, plus the daily citygate price of gas, for core customers that are out of balance in an EFO event. Currently, on an EFO day, a penalty of $50 per dth is imposed upon both core customers and noncore customers that are out of balance. Although PG&E proposes to increase the EFO penalty dramatically for all customers, PG&E proposes an even higher EFO penalty for core customers than for noncore customers. This differential treatment of core customers and noncore customers is not supported by the evidence. SPURR/ABAG contend that the penalties for customer noncompliance with an EFO should be proportionate to the harm caused to other customers. It is sufficient to impose either a fixed dollar penalty or a small dollar penalty, in addition to the actual cost of gas on the EFO day. It is not appropriate to combine a substantial fixed dollar penalty with the actual cost of gas, and it is not appropriate to establish different fixed dollar penalties for core and noncore customers.

14. Wild Goose

PG&E proposes to eliminate the involuntary diversion process and replace it with a curtailment procedure. Wild Goose is not opposed to PG&E's proposal, but PG&E should ensure that the curtailment procedure does not negatively impact the use of storage.

PG&E notes that one of the benefits of curtailment over diversion is that it allows the scheduling process to continue, which assures that additional supply from transmission and storage can be scheduled throughout the curtailment period. Wild Goose asserts that this provides value to storage holders, and serves as an incentive to contract for, and utilize, storage. This incentive, however, may be offset by PG&E's proposed methodology of requiring the load reduction to be shared across all noncore end use customers on a pro rata basis. Thus, even a noncore customer who contracted for storage would be curtailed in the same fashion as a customer who did not take such precautions. That is, the customer that contracted for storage will not be able to use firm storage withdrawals to avoid the curtailment.

Wild Goose asserts that unless PG&E's curtailment plan allows noncore customers to withdraw gas from storage, PG&E's proposal will only serve to deter customers from utilizing storage. PG&E and the Commission should, instead, be encouraging customers to store gas for periods of high demand.

PG&E's proposes a daily imbalance limit, with a wide tolerance band. This daily imbalance limit is proposed at plus or minus 35% of daily usage, or plus or minus 30,000 Dth, whichever is larger. If a customer exceeds this daily imbalance limit, a charge of $0.25 per Dth will be assessed. Wild Goose supports the adoption of this proposal with a slight modification. Wild Goose suggests that the daily imbalance limit be the lesser of plus or minus 35% of daily usage, or plus or minus 30,000 Dth. By making this change, the proposed limitation would apply to more customers. If this stricter standard were used, PG&E testified that approximately 33% of the imbalances created during 2000 and 2001 would have been subject to the proposed imbalance penalty. Wild Goose contends that such a modification would more accurately assign the costs of daily imbalances to those responsible for the imbalances and, more likely than not, have a greater impact on the reduction of OFOs.

Wild Goose also contends that if PG&E's daily imbalance proposal is to reduce the number of OFOs, the proposed penalty of $0.25 per Dth is insufficient in light of the fluctuations in gas prices. Instead, the penalty should be set at a level that will truly act as a deterrent.

Wild Goose points out that a number of parties object to PG&E's proposal to establish a daily imbalance limit. Since PG&E's current tariff requires customers to match supply and demand on a daily basis, each day a customer fails to do so is out of compliance with the tariff. Thus, PG&E's proposal is merely to assess a small penalty on those who are grossly out of compliance with its already approved tariff requirements. Since the proposed imbalance tolerance band will only capture the very large imbalances that drive the system to its pipeline inventory threshold resulting in an OFO, PG&E is only targeting the individuals that are creating the imbalances.

In order to more accurately assign the costs of daily imbalances to those responsible for the imbalances, the proposed imbalance tolerance band should be made more restrictive as Wild Goose recommends. At a minimum, the Commission should adopt PG&E's proposal leaving open the possibility of revisiting this issue as part of the OFO forum process.

15. PG&E

For PG&E's gas operations and balancing services, PG&E proposes to maintain the general structure, while making several changes to enhance or improve existing operational provisions. PG&E contends that these proposals will enhance operations and balancing services, especially during crisis periods. The proposed improvements are: (1) replacing the current diversion process with an end-use load curtailment process; (2) assigning additional storage capacity to the balancing service; (3) applying balancing rules and penalties to California gas production balancing entities so that these provisions are consistently applied to all market participants; and (4) allowing firm capacity to bump as available capacity in the second and third cycles consistent with interstate pipeline nomination standards. In certain instances, PG&E is willing to work out the implementation details in a workshop.

PG&E proposes to increase the storage capacity allocated to the balancing service to 75 MMcf per day of injection and withdrawal and 4.0 Bcf of inventory, from the existing levels of 50 MMcf per day of injection, 70 MMcf per day of withdrawal and 2.2 Bcf of inventory. PG&E contends that the added storage capacity will reduce the incidence of OFOs. By reassigning existing firm storage to balancing, and expanding storage for this purpose, PG&E is able to minimize costs.

The other adjustments that PG&E proposes are not a substitute for the added storage capacity, but instead are intended to reduce the number of OFOs by limiting some very large and adverse imbalances created by a few market players.

As for LGS' suggestion that PG&E should look to third-party storage providers for the incremental storage capacity, PG&E contends that this would jeopardize the effectiveness of the storage assets allocated to balancing, and also the balancing service since LGS is balanced on PG&E's system.

PG&E proposes to add a wide daily imbalance tolerance limit to the monthly balancing service option to discourage the extremely large daily imbalances that are created by a few balancing entities on the system. The proposed daily imbalance limit is the larger of either plus or minus 35 percent of daily usage, or plus or minus 30,000 Dth. An excess daily imbalance charge of $0.25 per Dth would be used as an incentive to stay within the limit.

Although Duke and NCGC suggest customer-specific OFOs or targeting customers that create the imbalance leading to OFOs, it has been PG&E's

experience that such specific measures do not work because targeted customers who are out of balance simply trade their imbalances with non-targeted customers. Although this results in the targeted customer being in balance, the net impact is that the system remains out of balance.

PG&E contends that its daily imbalance proposal accomplishes what NCGC suggests by bringing more focused attention on those who are the cause of large daily customer imbalances. The proposed daily tolerance band is so wide that it targets customers creating very large daily imbalances. Only 2% of the daily customer imbalances actually created during 2000 and 2001 would have exceeded the proposed tolerances. PG&E's proposal also focuses customer attention on daily imbalances by adding a mechanism that provides some financial consequence when the daily balancing obligation, which exists under today's tariff without financial consequence, is ignored. PG&E contends that the proposed limit is wide enough that PG&E believes it would be extremely rare that a customer who is actively attempting to manage the balancing obligations would never exceed this limit.

Wild Goose proposes that the tolerance limit be more stringent, *i.e.*, the lesser of plus or minus 35 percent, or plus or minus 30,000 Dth. PG&E believes that although this would provide more incentive for customers to remain in balance, it may be too restrictive because over 33% of the daily imbalances would be affected. PG&E believes that its proposed financial incentive will be adequate to eliminate the large imbalances that result in the calling of an OFO.

The Indicated Producers recommend that the daily imbalance requirement be rejected or deferred until the impact of other proposals can be evaluated. PG&E contends that its daily imbalance proposal is an appropriate response to encourage those customers not meeting the obligations under the existing tariff to reduce imbalances so they do not impact other customers.

PG&E proposes to replace the existing cash-out mechanism with an imbalance charge mechanism. This would apply to imbalances that exceed the monthly imbalance limit after the imbalance-trading period has concluded. PG&E asserts that the new proposal would eliminate the gaming associated with the existing cash-out mechanism. The proposed imbalance charge would hold the customer responsible for offsetting the physical imbalance. The proposed charge creates an incentive for the customer to be within the monthly imbalance limit after the trading period.

NCGC's reason for retaining the current cash-out mechanism is that it is responsive to the commodity cost of gas. PG&E contends that this is the reason why it should be replaced with the noncompliance charge. PG&E says that the problem is that customers compare the cash-out prices to the cost of gas in the next month. With significant price swings in daily and monthly gas prices, the cash-out prices can become an attractive economic alternative for the customer. The purpose of the current cash out mechanism and the proposed monthly imbalance charge is to impose a penalty to create the incentive for customers to keep their imbalances within the monthly tolerance level. These mechanisms are not effective if the customer uses them for economic gains.

PG&E proposes that California gas production imbalances, which are managed by a balancing entity through a CPBA, be subject to the same OFO requirements and noncompliance charges applicable to all other balancing entities. A CPBA imbalance is equal to the difference between the scheduled nominations of gas supply and the actual metered gas production flow. PG&E asserts that the OFO balancing requirements and noncompliance charges will remedy the problem of nominating gas in response to an OFO, even though there is not a physical increase or decrease in production. This paper imbalance can then be sold or traded to an end-user balancing entity to offset their real imbalance position, and avoid having to pay the OFO imbalance charge. The problem is that there is no change in the physical imbalance on the system.

PG&E proposes to replace the involuntary diversion process with a noncore customer curtailment process. PG&E contends that this will improve the ability to quickly reduce demand when a supply/demand imbalance threatens service to core customers. Duke, NCGC, and Wild Goose support PG&E's proposal but suggest certain refinements to the final development of the allowed burn quantities which establish the benchmark from which curtailment compliance is measured, and that storage gas withdrawal be utilized like a stand-by fuel to avoid or minimize curtailment. PG&E remains open to exploring and developing these refinements in a workshop or working group setting.

PG&E asserts that the concerns raised by the CCC/Calpine and the Indicated Producers are not sufficient to justify retaining the current diversion process. The concern that PG&E's proposal undermines the Gas Accord structure for backbone transmission rights is wrong because the proposal has no impact on the firm and as-available contract structure under the Gas Accord. Instead, PG&E's proposal offers a fair pro-rata burden on all noncore end-use customers during curtailments. When as-available contracts are diverted under the existing diversion process, the marketers holding the contracts decide which of their noncore customers are curtailed, which could result in some noncore customers having to bear a disproportionate share of the diversion burden.

Another concern of CCC/Calpine is that PG&E's proposal may provide PG&E's Core Procurement Department with an incentive to rely on curtailments rather than to acquire sufficient gas supply. PG&E contends that there is a significant incentive for its Core Procurement Department to have gas under contract because if there is insufficient gas, it will face a noncompliance charge of the market price plus a $60 per Dth imbalance charge, which is greater than the $50 per Dth for diverted gas. PG&E also contends that PG&E's Winter Reliability Standard proposal will also require PG&E's Core Procurement Department to meet a 1-in-10 year cold year event with firm capacity and supply, which reduces the need for noncore diversion or curtailment.

PG&E also points out that the curtailment process is easier to institute than a diversion process because PG&E is directly in contact with the end-user, whereas in a diversion a gas marketer may have to contact the end-use customer, who then is likely to check with PG&E before the end-user curtails its gas use.

CCC/Calpine also expressed concern about the value of keeping all four nomination cycles for the gas day during a curtailment event. PG&E contends that even if there is a limited amount of supply, there is a large incentive for added supply to be made available in the later nomination cycle. Under the diversion process, all nominations are halted after the first cycle, so even if gas is available, no more gas can come onto the system. Keeping the nomination cycle in place allows the possibility of more gas flowing onto the system that is short on supply.

CCC/Calpine propose that CPGs compensate noncore customers for curtailed quantities at a rate equal to the daily gas index price plus $10 per Dth. The Indicated Producers support this as well. PG&E recommends that this proposal be rejected because the gas supply is not taken from curtailed customers or their marketer and given to core customers. Instead, the gas supply remains with the original noncore customer unless or until it is renominated to another customer. If CPGs do not have enough supply to meet their demand, the CPGs will need to buy the supply from the curtailed suppliers or face high penalties of $60 per Dth, plus the daily citygate-indexed price of gas. Thus, curtailed customers will be in a position to readily sell the gas to CPGs at a market price.

PG&E asserts that the CCC/Calpine proposal will penalize CPGs by forcing them to purchase a positive imbalance from a noncore customer when there is an emergency. This will only provide a windfall to the curtailed noncore customers, and may provide an incentive for a curtailed noncore customer to withhold selling their extra gas supply to a CPG during a curtailment crisis.

ORA opposes the $60 per decatherm penalty for core customers who improperly forecast their demand. PG&E says that ORA misunderstands PG&E's proposal. The $60 per decatherm plus the daily cost of gas noncompliance charge proposal would be applicable during an EFO. PG&E states that the EFO noncompliance charge is not for improperly forecasting demand level. Instead, it is applicable when the supply that the CPG delivers to the PG&E system is less than the forecasted demand level provided to the CPG by the pipeline operator.

PG&E states that the Indicated Producers appear to argue that the existing diversion provisions provide a benefit to noncore end-users in that the noncore customer is paid $50 per Dth for its diverted gas supply and that the market price for selling the gas to a CPG may be less than $50 per Dth. PG&E points out that the diversion charge of $50 per Dth would go to the backbone shipper, most likely a marketer, and not the curtailed end-use customer. Under PG&E's system curtailment proposal, the curtailed noncore customer can sell their extra gas to a supply-short CPG at a market price. This market price could be very high. PG&E also contends that because noncore customers pay lower local transmission rates which reflects a lower level of reliability, CPGs should not be forced to pay curtailed noncore customers a fixed price for curtailed gas supply that might be higher than the market price. PG&E contends that its market price mechanism under its curtailment proposal is the fairest approach for both curtailed noncore customers and supply-short core customers.

The Indicated Producers recommend that the curtailment protocol proposal be modified to incorporate a firm versus interruptible distinction. PG&E points out that end-use customer delivery rights exist under local transmission tariffs and contracts, which have no firm or as-available distinction for noncore end-use customers under either the existing diversion process or the proposed curtailment process. The delivery point rights are the same for all noncore customers and are lower in priority than for core customers.

The Indicated Producers also make a proposal to retain the existing tariff language requirement that the core take all reasonable steps, including using (or attempting to use) its capacity and any as-available capacity before defaulting to a curtailment. As indicated by PG&E's witness, PG&E will continue to include this language in its tariffs.

CMTA opposes PG&E's proposal to replace the existing diversion process with a curtailment process. CMTA asserts that PG&E's proposal runs contrary to the structure of the Gas Accord, the proposal would absolve PG&E from wise management of transportation and storage capacity and gas procurement, and the proposal would provide an incentive to curtail. PG&E contends that the curtailment proposal does not undermine the primary contract rights established under the Gas Accord.

PG&E contends that CMTA's claim that the curtailment proposal will have noncore bearing the consequences of the failure of the core to get enough supply is not true. PG&E says that the diversion mechanism is not likely to be effective during a true emergency, so PG&E has proposed a system level curtailment procedure. Although this places a burden on noncore customers, the debate is over how this burden is imposed. As PG&E witness Johnson testified, the core has a significant incentive to buy gas at the market price from noncore customers (or their agents) under these emergency conditions.

Contrary to CMTA's argument, PG&E asserts that the core has an increased incentive under PG&E's curtailment proposal to have sufficient gas supply arrangements in place for cold temperature conditions compared to today's diversion procedure. Under today's diversion mechanism, core pays a $50 per Dth EFO imbalance penalty charge, and pays $50 per Dth diversion charge to the marketer for the gas supply. The second diversion charge effectively purchases gas supply from the noncore customer's gas marketer.

Under the proposed system curtailment mechanism, core pays a penalty of $60 per Dth plus the market price. In addition, core must still buy the gas at the market price in order to meet its balancing obligations. The total potential cost to core may be substantially increased, especially since the market price is likely to be very high during these emergencies. For example, if the market price is $40 per Dth, the total cost to core remains $100 per Dth ($50 per Dth EFO noncompliance plus $50 per Dth diversion charge) under a diversion, but increases to $140 per Dth ($60 per Dth plus the $40 per Dth market price for EFO noncompliance plus the $40 per Dth market price for the gas supply that the core still needs to purchase under the proposed system curtailment. Under the diversion process, the backbone shipper, and not the noncore customer, would receive the $50 per Dth diversion charge. Under the system curtailment procedure, the noncore customer, not the marketer, would be able to sell its gas supply to the core through a prearranged supply contract or on the gas day. The likely outcome is that the noncore customer will receive more compensation under PG&E's proposal than under today's mechanism. PG&E asserts that when a curtailment event occurs, there is an emergency situation on the pipeline, and it is not appropriate for marketers of noncore customers to benefit from emergency conditions.

C. Discussion

1. Balancing Service Proposals

a. Additional Storage Capacity

PG&E proposes to increase the storage capacity for its balancing service by increasing injection from 51 MDth/d to 76 MDth/d, increasing inventory from 2.2 MMDth to 4.1 MMDth, and increasing withdrawal from 71.4MDth/d to 76 MDth/d. In addition, PG&E proposes to allocate gas commodity to the balancing service. This would come from a transfer of 2 MMDth of non-cycle working gas which PG&E would reclassify as working gas for its balancing service.

PG&E presented testimony on the effect that increased injection, inventory, and withdrawal would have on OFOs. This was presented in Figure 8.1 of Exhibit 1. The storage study, Exhibit 18, which PG&E cites as support for the additional balancing, was used in cross-examination of the PG&E witness. Based on the storage study, and assuming customer balancing behavior remains constant, PG&E predicts that an additional 25 MDth / d will reduce the number of high OFOs by 20%, or by about 15 OFOs. (Ex. 1, p. 8-11; Ex. 18; 4 RT 424-425; 6 RT 550.) Although LGS asked questions of the PG&E witness regarding the data and assumptions supporting Figure 8.1, none of the other parties presented any testimony which contradicts the relationship shown in Figure 8.1 of Exhibit 1. (*See* 6 RT 565-579.)

NCGC suggests that an additional 25 MDth / d of injection capacity be added to PG&E's proposal. According to PG&E's analysis, this would reduce the number of OFOs even more. We do not believe that this extra 25 MDth / d of additional injection is needed at this time. Instead, PG&E's proposal should be implemented and monitored over 2004 to determine how effective this additional storage capacity will be.

LGS also raised the issue of whether additional balancing should be provided by third party storage providers. Exhibit 18 described some contacts that PG&E had with Wild Goose, and with Western Hub Properties, a parent company of LGS. Exhibit 18 contained some preliminary estimates of how much these two storage providers could provide the service for in the 2000 to 2001 timeframe. Although this raises a cost savings issue, PG&E is the entity that has the responsibility and certificated authority to provide gas services to its customers.

Based on the record in this proceeding, we adopt PG&E's proposal to increase its storage capacity for its balancing service by increasing injection to 76 MDth / d, increasing the inventory to 4.1 MMDth, and increasing withdrawal to 76 MDth / d. Those increases are reflected in the assignment of storage capacity for 2004 shown in Table 4.

PG&E shall monitor the effectiveness of this additional storage capacity in its daily operations and balancing. PG&E shall provide a report in its 2005 transmission and storage rate case about this additional storage capacity, and its effects on the system.

Next, we turn to PG&E's proposal to allocate 2 MMDth of gas to the balancing service for 2004. PG&E proposes that the gas come from a transfer of 2 MMDth of non-cycle working gas, which PG&E seeks to reclassify as working gas for its balancing service.

No one has objected to PG&E's proposal to reclassify this non-cycle working gas as working gas for use in its balancing service. Based on the benefit that the increase in balancing will bring using existing assets, we adopt PG&E's proposal to reclassify the 2 MMDth of gas as working gas for use in PG&E's balancing service.

b. Daily Imbalance Limit For the Monthly Balancing Option

PG&E proposes to impose a daily imbalance limit, with a wide tolerance band. PG&E also proposes that a $0.25 per Dth excess imbalance charge be imposed for all daily imbalances that exceed the daily imbalance limit.

Several parties believe that the daily imbalance proposal and related charge do more harm than good. Instead of punishing the entities who cause large imbalances on the system, PG&E's proposal would penalize those who are out of balance on a particular day, but do not contribute to the system imbalance.

Since the daily imbalance proposal is to reduce imbalances and the number of OFOs, some of the parties suggest that other measures targeting the offenders should be used by PG&E. Some also suggest that the additional storage capacity for balancing should be used first to determine if it helps solve the OFO problem before imposing the daily imbalance penalty.

PG&E's proposal seems to affect a large group of customers who are not the cause of large system imbalances. To impose an excess imbalance charge on them on a daily basis at this time is counterproductive. PG&E should explore other ways in which to target those who cause the imbalances, which lead to OFOs. We also agree with some of the parties that the additional storage capacity for balancing services should be used first to determine its effect on managing imbalances and OFOs, before additional measures are considered to remedy these problems.

Accordingly, PG&E's proposal for a daily imbalance limit and related excess imbalance charge is not adopted.

c. Disposition of Monthly Imbalances

PG&E proposes that instead of using the current cash-out mechanism, that it be replaced with an imbalance charge for monthly imbalances in excess of the five percent tolerance band. This imbalance charge would be 100% of the MCI. The imbalance would be carried forward, and the customer would be responsible for clearing the imbalance. PG&E also proposes that for contracts that are terminated, the prices at which PG&E buys and sells gas from these entities be changed to the MCI for a negative imbalance cash-out, and the LCI for a positive imbalance cash-out.

NCGC opposes the elimination of the cash-out mechanism, and points out that the mechanism generates revenues. NCGC also points out that the cash-out prices in Schedule G-BAL provide an incentive for a customer to stay within the 5% monthly imbalance tolerance, and that PG&E's cash-out is disadvantageous for the customer and advantageous for PG&E.

PG&E's rebuttal testimony in Exhibit 4 explained that the volatility in gas prices lead some customers to accumulate large monthly imbalances that they will cash out when prices appear attractive. PG&E's testimony also states:

> "This excessive imbalance is then effectively sold to (or purchased from) the pipeline and is a permanent transfer into (or out of) the storage inventory allocated for the balancing service. When these cash-outs are large, or when they cumulatively move in the same direction, the available storage inventory to support balancing services can be filled (or depleted). As a result, the balancing service available to the market is limited, impacting all customers." (Ex. 4, p. 8-9.)

On balance, we believe the current cash-out mechanism is advantageous for ratepayers, as the revenues and expenses go into the BCA. The prices used for the cash-out are also advantageous. The only apparent impact is to the balancing operations. However, with the additional storage capacity assigned to balancing, this should help the problem that PG&E has described.

Accordingly, we do not adopt PG&E's proposal to replace the cash-out mechanism with an imbalance charge for monthly imbalances in excess of the tolerance band. For 2004, PG&E shall continue to use the existing cash-out mechanism.

With respect to the prices at which PG&E buys or sells gas for terminated contracts, no one has commented on the proposed rates that PG&E proposes to use. We adopt PG&E's proposal that for contracts that are terminated, the prices at which PG&E buys and sells gas from these entities be changed to the MCI for a negative imbalance cash-out, and the LCI for a positive imbalance cash-out.

d. OFO Obligations for California Gas Production

As part of the Gas Accord Settlement Agreement, PG&E and the California gas producers agreed that a standard CPBA would be implemented. (73 CPUC2d at 835.) Under the CPBA, the balancing rules for California production gas differ from the balancing rules for end-use customers, and do not have OFO or EFO noncompliance charges.

According to PG&E, the majority of California production gas is under the management of end-use customers, who are subject to flow order noncompliance charges. PG&E contends that the nominations of California production gas are being used in a way that offset end-use customer imbalances to avoid OFO or EFO noncompliance charges.

PG&E proposes that California gas production imbalances be subject to the same OFO and EFO tolerance bands and noncompliance charges as other end-use customers.

In support of PG&E's proposal, PG&E developed Table 8-1 of Exhibit 1 which shows 45 OFOs over a period of two years, and Table 8-1 of Exhibit 4 which shows CPBA nominations, actual production, and imbalances for June

2002. The data presented shows that in 35 of the 45 OFO events, California gas production imbalances exceeded the tolerance band required by the OFO.

CNGPA did not present any testimony which refutes the data shown in the two tables, nor did CNGPA's testimony or its reply brief address the table or PG&E's conclusions about the tables. Instead, the arguments of CNGPA focused on why the application of the same rules and charges as other end-use customers would be discriminatory, in violation of certain provisions of the Public Utilities Code, and why it would be difficult to comply with the OFOs.

We are not persuaded that the proposal of PG&E to apply the same OFO and EFO rules and charges that other end-users have would discriminate against California gas producers. PG&E is merely applying the same set of rules in 2004 to California gas producers and other end-use customers. As part of the Gas Accord, PG&E and the California gas producers agreed to the implementation of the CPBA. However, the extension of the Gas Accord ends on December 31, 2003. Instead of treating California gas producers differently in 2004, they will be treated the same as other end-use customers.

CNGPA also cites §§ 785 and 785.2 as reasons why PG&E's proposal should not apply to California gas production. Our reading of those code sections do not suggest that PG&E's proposal would violate those provisions of the Code.

With regard to CNGPA's arguments that they are being denied access to real-time operating and balancing data, and to PG&E's flow patterns and pipeline pressures, PG&E shall be directed to work with CNGPA to resolve these issues so that CNGPA can timely respond to any OFO or EFO that might be called.

Based on the record, PG&E's proposal to apply the same OFO and EFO tolerance bands and noncompliance charges that are currently in place for end-use customers, to California gas production, is adopted.

e. Measuring Core Procurement Groups' Compliance

PG&E recommends that three proposals be adopted for CPGs. The first proposal is to use the Determined Usage forecast to calculate the compliance of CPGs with flow orders. The second proposal is that the EFO noncompliance charge for all CPGs be calculated using the lower of the Determined Usage or the end-of-flow-day core demand forecast, as compared to the CPG's scheduled supply. PG&E's third proposal is that the EFO noncompliance charges for CPGs be set at a higher level than for noncore customers.

ORA and SPURR/ABAG raised concerns regarding the noncompliance charge for CPGs in the event of an EFO. They point out that the core's noncompliance charge ($60 plus DCI per Dth) should not be higher than the noncore's compliance charge ($50 plus DCI per Dth), and that the index component of the charge should not be used.

We agree with ORA and SPURR/ABAG that PG&E has not demonstrated why the core's noncompliance charge for an EFO should be higher than the noncore's charge. We address the index argument later in this section, and determine the gas index component should be used. The EFO noncompliance charge for CPGs shall be equivalent to the noncore's EFO noncompliance charge of $50 plus DCI per Dth. Thus, PG&E's proposal that the EFO noncompliance charge for CPGs be set at a higher level than for noncore customers is not adopted. Instead, PG&E shall use the same EFO noncompliance charge for both CPGs and noncore.

No other party submitted any testimony or raised objections to the two other PG&E proposals.

We adopt PG&E's proposal to use the Determined Usage forecast to calculate the compliance of CPGs with flow orders. We also adopt PG&E's

proposal that the EFO noncompliance charge for all CPGs be calculated using the lower of the Determined Usage or the end-of-flow-day core demand forecast, as compared to the CPG's scheduled supply.

2. Bumping Proposal

PG&E proposes to adopt the NAESB bumping process into its gas nomination process.

No one submitted any testimony or raised any objections to PG&E's proposal. We adopt PG&E's proposal to include the NAESB bumping process as part of PG&E's gas nomination process.

3. Supply Shortfalls and Capacity Constraints Proposals

a. Diversion or Curtailment

PG&E's proposed curtailment process seeks to remedy some operational concerns with the current diversion process. However, as noted by PG&E, the involuntary diversion process has never been used.

Several of the parties have expressed concerns about how the curtailment process would work under certain situations. PG&E's proposal leaves a lot of these questions unanswered. Although the parties appear willing to work out the details in a workshop, it is unclear whether a workshop would resolve all of these concerns.

Other parties also expressed concern about the impact a curtailment could have on a business, and that curtailed noncore customers would not be compensated, as they would be under a diversion. The third party storage providers believe that a curtailment process must also allow for a storage customer to withdraw gas that is already in storage.

We have considered the testimony of the parties on this subject, and the arguments of the parties. We believe that the curtailment process should be developed further by PG&E and other interested parties before we consider whether it should be adopted. Instead of adopting a curtailment process with a lot of unknowns, or tentatively approving a process subject to a workshop, we believe that the existing diversion process and rules from the Gas Accord should remain in place for 2004.

Should PG&E continue to believe that a curtailment process is a more appropriate tool, PG&E should develop its proposal further. Since many of the parties expressed a willingness to hold a workshop, it is in PG&E's interest to discuss its curtailment plan with these parties in 2004. We will permit the curtailment issue to be addressed in the 2005 rate case.

Accordingly, we do not adopt PG&E's proposal to replace the existing diversion process with a curtailment process for 2004, nor do we adopt the related noncompliance charge for a system-level curtailment. Instead, the current diversion process and rules shall remain in effect for 2004.

b. Local Curtailments

PG&E proposes to continue the existing local curtailment process as described at pages 8-30 to 8-31 of Exhibit 1. Currently, there is no noncompliance charge for a local curtailment. PG&E proposes that a $50 plus DCI per Dth noncompliance charge be imposed for usage that exceeds the maximum allowable usage quantity. The payment of the noncompliance charge does not relieve the customer of the duty to resolve any imbalances, and the customer is also subject to any EFO or OFO noncompliance charge.

None of the other parties presented any testimony on the local curtailment process or the proposed noncompliance charge.

We adopt the current local curtailment process for use in PG&E's gas structure for 2004 and 2005. We also adopt PG&E's proposal for a $50 plus DCI noncompliance charge for local curtailments for use in 2004.

4. Shrinkage Proposals

PG&E has two shrinkage proposals. The first proposal is to update the shrinkage allowance on an annual basis, and if needed, to file separate advice letters during the year to adjust the shrinkage allowances to better match the actual shrinkage experienced on the system. The second proposal is to collect the cost of GDU and LUAF associated with PG&E's gas storage operations, from all scheduled storage injection volumes through an in-kind shrinkage allowance.

No other parties submitted any testimony or filed comments on PG&E's shrinkage proposals.

PG&E's proposal to allow PG&E to update its shrinkage allowances on an annual basis through an advice letter compliance filing, and, if necessary, to make separate advice letter filings to adjust shrinkage allowances at other times of the year in order to better match the actual shrinkage experienced on PG&E's system, is adopted. The annual filing for 2004 shall occur on or before December 31, 2003, with an effective date of January 1, 2004. The BCAP shall continue to be the proceeding in which the pipeline shrinkage calculation methodology is determined, and the proportion of LUAF and GDU that are to be assigned to transmission and distribution shrinkage.

PG&E's proposal that an in-kind shrinkage allowance, using the methodology described at page 8-34 of Exhibit 1, be applied to all scheduled storage injection volumes, is adopted. The gas storage shrinkage costs that are currently collected through the transportation in-kind shrinkage allowances are to be excluded from the transmission and distribution in-kind shrinkage allowances. PG&E's proposal that it be allowed to continue to recover in storage rates a portion of the cost of electricity used by PG&E's gas department to operate its storage field is adopted.

Due to the non-adoption of PG&E's request to sell the non-cycle working gas, the storage cycle quantity has been changed. PG&E shall calculate the in-kind shrinkage allowance for the 2004 injection season, and shall make an advice letter compliance filing no later than March 19, 2004.

5. Noncompliance Charges Proposal

PG&E proposes that most of the noncompliance charges be modified to include a cost of gas component. The gas component to be used is one of three gas indexes. The noncompliance charges, with the relevant index, is shown in Table 8-6 of Exhibit 1.

ORA and SPURR/ABAG raised concerns regarding the noncompliance charge for CPGs in the event of an EFO. They question whether the noncompliance charge, with the index included, is an appropriate price to pay.

Aside from the higher price that a CPG will have to pay if it does not comply with an EFO, ORA and SPURR/ABAG have not rebutted PG&E's argument that adding a component which includes a gas index price will better reflect supply conditions and result in responsive behavior.

ORA's argument that the higher EFO noncompliance charge with the gas index component should not be considered because there is a correlation with the Winter Firm Reliability Requirement is not persuasive. PG&E's testimony regarding EFOs establishes sufficient reasons to add a gas index component to the noncompliance charges.

We will permit PG&E to use the gas index price in its noncompliance charges. As mentioned earlier, the core charge for an EFO shall be $50 plus the DCI.

Accordingly, we adopt PG&E's proposal that most of the noncompliance charges incorporate one of three relevant gas indexes.

We also authorize PG&E to use the noncompliance charges shown in Table 8-6 of Exhibit 1 for 2004, except for those noncompliance charges that are related to proposals that we do not adopt, or that we have changed the amount of the charge.

6. Anonymous Trading Platform Proposal

PG&E proposes to eliminate the electronic trading platform that was approved in D.00-05-049, and to credit back to the BCA $656,000 of the $700,000 that was authorized to implement the trading platform.[40]

No other party submitted testimony or commented on PG&E's proposal.

Since no one expressed an interest in continuing with the development of a third party electronic trading platform, we adopt PG&E's proposal to eliminate the third party trading platform and services that was adopted as part of the settlement in D.00-05-049. As part of PG&E's proposal, PG&E shall credit back to the BCA the unused portion of the monies that were allocated to this project.

IX. Operating and Maintenance Exenses

A. Summary of O&M Expenses

PG&E's forecast of Operating and Maintenance (O&M) expenses reflects the costs to operate and maintain PG&E's gas transmission, storage, and gathering facilities for 2004, and costs for related customer service activities. PG&E's forecast of O&M expenses are set forth in Chapter 9 of Exhibit 3. For 2004, PG&E's forecast of O&M expenses in 2004 dollars is $90.959 million.

PG&E's O&M forecast was developed using recorded expenses for 2001 as the base. Adjustments were made to the base for unusual and non-recurring

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[40] The objective of the trading platform was to trade imbalances and backbone capacity contracts on an anonymous basis.

items to provide an adjusted year 2001 recorded base forecast. Incremental adjustments were then made to the adjusted year 2001 recorded base to determine the 2004 forecast.

One of the incremental adjustments that PG&E made for 2004 is for computer system modifications that are needed to support the new and modified services that are reflected in PG&E's proposals. PG&E estimates these modifications to cost $1.769 million in 2001 dollars. Table 9-2 of Exhibit 3 lists the various computer system modifications that PG&E believes necessary.

Another incremental adjustment is for work related to the Pipeline Safety Improvement Act of 2002. This legislation was signed into law on December 17, 2002. (Public Law 107-355.) The law requires that pipeline owners or operators complete baseline integrity assessments and inspections of all gas transmission pipelines located within high consequence areas within seven to ten years, depending on the assessment method used. PG&E estimates that 2200 miles of its gas transmission pipeline will be affected by this law. In order to comply with the law, PG&E estimates it will have to assess 150 to 220 miles of pipeline each year for 10 years.

Much of this assessment will be done by "smart pigging,"[41] the costs of which are discussed in the capital expenditures section. PG&E estimates that the

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[41] Smart pigging is the term that is used to refer to the process of sending a data gathering instrument through an operating pipeline to measure steel pipe wall thickness, and to look for corrosion, metal loss, voids, defects, and dents. PG&E notes some pipelines may have to be retrofitted to allow for smart pigging, and that there may be cost uncertainties associated with this retrofitting work, especially in urban areas.

other assessments will likely be done by direct assessment[42] and the associated physical excavations. In 2004, PG&E plans to conduct direct assessment on 200 miles of pipeline, and estimates that 100 physical excavations will be made to inspect sections of the pipeline. PG&E estimates that this will result in O&M costs of $4.416 million for 2004.

PG&E also forecasts an increase in Non-Reimbursable Relocations. Non-Reimbursable Relocations are costs to relocate pipelines that are in conflict with Public Works projects such as sewer and storm drain lines. PG&E estimates expenses of $250,900 for 2004.

Adjustments for 2004 were also made for O&M work related to the storage system. An increase of $194,000 was included to perform an evaluation of Line 57B and the stability of the Mildred Island levees, which the pipeline crosses.

B. Positions of the Parties

1. Mirant

Mirant points out that ORA, which normally takes the lead in analyzing and responding to revenue requirement issues, had only limited resources in this proceeding. As a result, ORA did not perform any detailed cost or policy analyses of PG&E's proposals. Although Mirant and other parties tried to explore a number of revenue requirement issues through the cross-examination

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[42] Direct assessment is the industry process of verifying pipeline integrity by analyzing physical data on the pipeline (age, type of girth welds, wall thickness, coating, operating safety factor) and the results of electronic surveys and tests taken on the ground above the pipeline. Physical excavations of various segments of the pipeline are performed in order to validate the accuracy of the direct assessment data and model.

of PG&E's witnesses, this is not a substitute for a thorough examination of the books and accounts that are normally conducted by ORA.

Several parties probed the reasonableness of PG&E's revenue requirement calculations, giving particular attention to PG&E's estimates of operation and maintenance expenses and capital expenditures. These efforts have raised concerns about the sufficiency of PG&E's cost of service analysis, and the associated revenue requirement.

The greatest increase in PG&E's O&M expense forecast for 2004 is the cost of pipeline integrity inspections. Between the date that PG&E served its testimony in December 2002, to its update filing of March 2003, PG&E's estimate of this expense rose from $600,000 to $4.4 million. PG&E also expects that these costs will continue to increase in future years. Without the benefit of a broader review by ORA staff, Mirant contends that the reasonableness of PG&E's O&M expense estimate is unconfirmed.

Mirant recommends that PG&E's cost of service study, and the revenue requirement conclusions that flow from the study, should not be implemented because they have not been comprehensively reviewed by ORA. The Commission should allow no more than the Gas Accord's annual escalation factor of 2.5%, pending a full rate review for year 2005.

2. Palo Alto

Palo Alto supports TURN's adjustments to PG&E's cost of levee restoration at Mildred Island, the Non-Reimbursable Relocation costs, and the costs to modify PG&E's computer systems. This has a 2004 revenue requirement effect of $113,200, $100,000, and $1,070,000, respectively.

Palo Alto believes that these amounts should be excluded from the 2004 O&M costs because these activities were not identified as scoping memo issues.

3. TURN

TURN has identified three areas in which PG&E's gas O&M expenses could be reduced by a total of $1,255,000 for 2004.

PG&E proposes to recover $1,769,000 in computer system change costs related to implementing new provisions of the Gas Accord in 2004 rates. TURN recommends amortizing the total system change costs of $2,098,000 over three years, reducing the revenue requirement by $1,070,000.

PG&E replied that the computer system change costs are related to programming work, and not the purchase of hardware, and therefore are not subject to amortization under Generally Accepted Accounting Principles (GAAP). TURN contends that while GAAP is a guide, they do not control accounting for ratemaking purposes. TURN points out that the Commission has approved capitalizing software costs based on the amount of software development costs and the expected useful life of the project. In PG&E's last general rate case, the Commission adopted a fifteen year service life for capitalized computer plant, including both hardware and software.

TURN's second O&M change is to amortize the $242,500 total cost of the Mildred Island Levee stability project over three years. This would reduce the 2004 revenue requirement by $113,200. PG&E replied that since this project involved "remediation work on the levee," rather than capital plant, that it was not subject to amortization under GAAP. TURN contends that the GAAP guidelines are not controlling, and that these types of labor costs may be capitalized over three years.

TURN's third O&M change is to use a six-year average of recorded data instead of the three-year average of 1999, 2000 and forecast 2002 data that PG&E used to forecast the 2004 Non-Reimbursable Relocations. PG&E did not use 2001 data because it claimed that there was an unusually low level of non-reimbursable relocations. TURN's use of six years of recorded data results in a forecast of $178,500 while PG&E's forecast results in $250,900.[43] TURN contends that PG&E has provided no argument or data indicating that the 2001 data is a statistical anomaly that should be excluded.

4. PG&E

PG&E's testimony presented estimates of the expenses that PG&E expects to incur in operating and maintaining PG&E's gas transmission system. These forecasts of operating and maintenance expenses involve activities related to gas transmission, gas storage, gas gathering facilities, and customer service for 2004. Except for the concerns of Mirant and TURN, which are addressed below, PG&E contends that the proposed funding levels for all other expense categories were unopposed and should be adopted.

TURN has proposed three reductions to reduce gas O&M expenses. First, TURN recommends amortizing the costs associated with computer system changes to implement the Gas Accord II-2004 provisions over a three-year period, which would reduce the revenue requirement by $1.07 million. Second, TURN proposes amortizing the $242,500 total cost associated with the Mildred Island Levee Stability Project over three years, which would reduce the 2004 revenue requirement by $113,200. And third, TURN proposes that the 2004 forecast for Non-Reimbursable Relocations be lowered from $250,900 to $178,500.

PG&E states that TURN's proposal to amortize the costs associated with computer system changes should not be adopted. The System Development

[43] If PG&E's methodology is accepted, PG&E's amount should be reduced by $12,700 based on recorded 2002 data. (Ex. 52, p. 8, fn. 11.)

Work involves programming effort instead of the purchase of hardware or off-the-shelf software. To amortize programming expenses, which are not capital investments, is contrary to GAAP. Since these expenses are planned and estimated to be incurred in 2004, they should be treated as an expense and recovered in 2004.

PG&E also states that there is no basis for amortizing the costs associated with the Mildred Island Levee Stability Project because the work does not involve capital plant. The project involves remediation work on the levees to ensure that issues with cover and stability do not present a risk to PG&E's Line 57B. To amortize this cost would be improper under GAAP. Since these expenses are estimated to be incurred in 2004, they should be recovered in the same year.

As for TURN's proposal that the 2004 forecast for Non-Reimbursable Relocations be lowered, PG&E contends that its forecast is more accurate than TURN's because it uses more current data (1999, 2000 and 2002),[44] and excludes the expense for 2001 ($42,900) which were unusually low. PG&E says it is clear from examining the recorded data that non-reimbursable relocations have been growing and that it is more appropriate to use recent data in preparing a 2004 forecast.

Mirant stated that without the benefit of a broader review of the Pipeline Integrity Program Expenditures by ORA, the reasonableness of PG&E's O&M expense estimate is unconfirmed. PG&E points out that Mirant has made no showing whatsoever to challenge the accuracy of the Pipeline Integrity expense

[44] The average for these three years was $250,900.

forecast, and ORA's opening brief raised no specific opposition to PG&E's O&M forecast. The PG&E witness explained that the increased spending for the pipeline expenses were based on the most current information available, and it is anticipated that work in 2005 and 2006 will be greater than 2004.

C. Discussion

PG&E advocates that since no one objected to most of the O&M expenses that were forecast for 2004, the uncontested expenses should be approved, and that the challenges to the other expenses should be resolved in PG&E's favor. Mirant, and some of the other parties assert that there has not been a careful review of the O&M expenses and capital expenditures, and that the cross-examination revealed only a sampling of possible adjustments. Mirant suggests that if the Commission does not postpone the costs and rates portion of this proceeding, expenses should only be escalated by 2.5% for 2004, the same cost escalation factor in the Gas Accord.

We agree with Mirant and others that a comprehensive review of PG&E's expenses should be done. However, given the time and resource constraints of all the parties, such a review was not performed. Although such a review was not done, that does not mean PG&E's forecasted O&M expenses, and other expenses that it is requesting, should be summarily approved. The testimony, cross examination, and argument were able to highlight some areas of possible adjustments, as discussed below and in the capital expenditures section. A more thorough review by ORA may have uncovered additional adjustments.

We note that the rates adopted in this proceeding are only for 2004. ORA will have the opportunity to comprehensively review PG&E's expenses in early 2004 for rates to be set in 2005. ORA should make plans to allocate resources accordingly.

Mirant raised concern about the forecasts of O&M expenses in 2004 for the Pipeline Safety Improvement Act of 2002 (Pub. Law 107-355, Dec. 17, 2002).[45] In 2004, PG&E forecasts the amount at approximately $4,415,800. According to PG&E's workpapers, these expenses were $20,700 and $630,700 in 2002 and 2003, respectively. (Ex. 39, p. 9; Ex. 40, p. 10; Ex. 1, p. 9-9.)

As described by PG&E, and our review of the Pipeline Safety Act, the expenditures in 2002 and 2003 are fairly low because the law was not enacted until December 17, 2002. However, the deadlines set forth in Section 14 of the Pipeline Safety Act provides for the Secretary of Transportation to "issue regulations prescribing standards to direct an operator's conduct of a risk analysis and adoption and implementation of an integrity management program …." These regulations are to be issued by December 17, 2003. The law also provides that:

> "The regulations shall require an operator to conduct a risk analysis and adopt an integrity management program within a time period prescribed by the Secretary, ending not later than 24 months after such date of enactment. Not later than 18 months after such date of enactment, each operator of a gas pipeline facility shall begin a baseline integrity assessment described in paragraph (3)."

Our reading of the above deadlines suggests that work associated with this law will occur in 2004. There is no doubt that expenses and capital expenditures will occur to comply with the Pipeline Safety Act. The question is when will these costs be incurred, and how much the costs will be.

The issue of when the costs will be incurred is known. The baseline integrity assessment must begin not later than June 17, 2004, and the risk analysis

[45] Hereinafter referred to as the "Pipeline Safety Act."

and adoption of an integrity management program must begin no later than December 17, 2004.

The costs to be incurred are more of a variable. The work for baseline integrity assessments, risk analysis, and the adoption of an integrity management program will start up in 2004. However, the deadlines in the Pipeline Safety Act does not require the baseline integrity assessment to begin until mid-year of 2004. The regulations for the Pipeline Safety Act have not been issued yet, so the risk analysis may not occur until later in 2004. The O&M expenses that PG&E forecasts for 2004 are $4,415,800 in 2001 dollars. Using the escalation factors provided by PG&E, the O&M expense for the Pipeline Safety Act in 2004 dollars is approximately $5,005,953.

We have no doubt that PG&E will incur O&M expenses for work associated with the Pipeline Safety Act. However, the deadlines in the law allow for much of this work to occur in the second half of 2004. Since PG&E estimates $11 million per year in capital expenditures for the Pipeline Safety Act, we use the $5,005,953 as the one-year estimate for O&M in 2004. Since much of the work associated with the law is not required to begin until mid-2004, it is appropriate to reduce the O&M expense of approximately $5,005,953 by half, to reflect six months of expenses. This adjustment to the O&M expense is reflected in Table 2 of Appendix A of this decision.[46]

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[46] It is our intent that PG&E's forecast O&M expense of $4,415,800 for 2004 in 2001 dollars, adjusted for 2004 dollars using the escalation factors, shall be used to calculate the adjustment. The revenue requirement that we adopt today for 2004 shall serve as the maximum cap. That is, should the O&M adjustment, or other adjustments made in today's decision, result in a higher number than what we have calculated, which would increase the revenue requirement amount, the adopted revenue requirement amount

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We have reviewed the reductions that TURN has proposed for the computer system change costs to implement its proposals, the Mildred Island Levee stability project, and the Non-Reimbursable Relocations. The computer system change costs and the Mildred Island costs is a question of whether the costs should be expensed or spread over several years. The examples provided by TURN and PG&E lead us to adopt PG&E's position, and to expense these two costs. We note that the computer system costs could have been reduced somewhat because not all of the planned computer programming will be needed in light of which proposals we adopt in today's decision.

On the Non-Reimbursable Relocations, we adopt PG&E's position. We believe that the more recent data for this expense item reflects a more accurate forecast than the six-year average that TURN used.

We adopt PG&E's forecast of O&M expense for 2004, less the adjustment to the O&M costs for the Pipeline Safety Act. PG&E shall be directed to make this adjustment to the O&M expense.

X. Capital Expenditures

A. Summary of Capital Expenditures

This section addresses the capital expenditures that PG&E plans to incur in 2004 to operate and maintain its gas transmission, storage and gathering system. For 2004, PG&E's forecast of capital expenditures is $143.3 million in 2001 nominal dollars.[47] The capital expenditures are used to calculate the cost of service, which is discussed in the next section.

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shall not be changed. Should the adjustments result in a lower revenue requirement amount, the adopted revenue requirement amount shall apply.

[47] PG&E notes that some of the capital expenditures are needed to meet governmental requirements, and that any mandated changes to these requirements may result in a

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Of the forecasted total for capital expenditures, $60.2 million is for base capital expenditures[48] for pipeline related work. The pipeline related work is made up of the following seven Major Work Categories (MWCs):[49] (1) Pipeline Safety & Reliability; (2) Work Requested By Others; (3) New Business; (4) Pipeline Capacity; (5) Power Plant Connections; (6) Power Plant Metering Costs; and (7) Pipeline Safety Law.

The 2004 forecast of pipeline related work is almost double the amount of base pipeline related work in 2001. PG&E attributes the increase in spending to primarily two factors: (1) installation of capacity, service extensions, and meters to serve gas-fired power plant demands; and (2) anticipated modifications to PG&E's gas transmission pipeline system in response to pipeline safety legislation.

Much of the assessment required by the Pipeline Safety Act will be accomplished by smart pigging. PG&E estimates that for 2004, the capital expenditures needed will be $11 million, with a continuous investment of $11 million per year from 2005 through 2013.

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change in the capital expenditures needed to fulfill these requirements. PG&E proposes to adjust funding for such changes, if they increase or decrease, through the Governmental Mechanism, which is discussed later in this decision.

[48] According to PG&E, base capital expenditures include all capital projects that address regulatory compliance, safety, reliability, increased system capacity, efficiency, serving new customer load, and facility relocations. Base capital expenditures tend to be relatively consistent from year-to-year.

[49] MWCs consolidate and categorize capital expenditures by asset and work activities.

PG&E estimates that $28.5 million of the forecasted $143.3 million in 2004 capital expenditures will be for base capital expenditures for station reliability,[50] and $23.5 million will be for base capital expenditures for environmental work.[51] Base capital expenditures for work related to other MWCs[52] is estimated at $5 million.

Of the $143.3 million in 2004 capital expenditures, PG&E estimates that non-recurring capital expenditures of $26.1 million will be needed to incrementally expand PG&E's transmission capacity or improve overall system reliability.

As part of the $26.1 million, PG&E proposes to use $2 million to reinforce the local transmission system in order to improve noncore reliability to a 1-in-10 year cold temperature event, as mentioned earlier in PG&E's Winter Reliability Standard proposal. The total cost of reinforcing the local transmission system to meet the Winter Reliability Proposal is estimated at $42 million from 2004 through 2007.

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[50] Station reliability work includes costs associated with improving the safety and maintaining the reliability of the gas compression stations and underground gas storage facilities by replacing aging facilities. An example is the replacement of equipment that has high outage frequency or excessive maintenance costs.

[51] Environmental work is for costs to modify or improve PG&E facilities in order to comply with environmental rules and regulations. An example of these expenditures is the installation of nitrous oxide emission reduction equipment at compressor stations.

[52] The four small MWCs which make up this category consists of gas gathering, tools and equipment, office buildings, and gas system operations network systems.

B. Positions of the Parties

1. CCC/Calpine

CCC / Calpine claim that the backbone level rate proposal will reduce costs on PG&E's local transmission system by eliminating PG&E's costs of reinforcing local transmission facilities.

2. Mirant

PG&E provided estimates of PG&E's capital expenditures for inclusion in plant in service for 2004. These estimates of investments in Power Plant Connections and Power Plant Metering were itemized in Figure 10-2 at page 10-6 of Exhibit 3. As a result of the slowdown in new power plant service extension requests, PG&E's March 2003 update to this testimony reduced the estimates of power plant metering investments from $9 million to $4.8 million for combined years 2003 and 2004. Mirant asserts that it is unclear whether this reduced estimate was incorporated by PG&E in calculating its revenue requirement.

Mirant also asserts that PG&E's proposed Gas Rule 27 could affect future power plant connection and metering costs. PG&E's projections of capital expenditures are substantial, and include $35.8 million for capacity additions and new business connections. Mirant contends that there has not been an adequate accounting and review of these projected capital expenditures.

Mirant also points out concerns regarding PG&E's projections of capital investments on pipeline safety projects. PG&E's Figure 10-2 shows $86.5 million of capital costs in this category for 2001 through 2004. There is also $11 million in 2004 for investments related to the Pipeline Safety Act. Mirant contends that PG&E's witness was unfamiliar with the elements that made up the total.

Mirant is also concerned that PG&E's inclusion in rate base of $80.5 million in non-cycled working gas costs is another example of why rates should not be based on a cost of service study that has not been adequately analyzed. PG&E's witness acknowledged this was contrary to historical practice whereby PG&E receives only the short-term interest rate on that investment. Although PG&E had been compensated at the short-term commercial lending rate for this working gas, the inclusion of $80.5 million in rate base to earn the authorized rate of return is cause for concern. Since this issue was buried in the cost of service study and the workpapers, and parties have not had an opportunity to study this issue, the Commission must carefully consider whether it should implement rates based on a cost of service study that has not been adequately reviewed.

Mirant recommends that, pending a full rate review for year 2005, rates remain the same, or the Commission should allow no more than the Gas Accord's annual escalation factor of 2.5%. PG&E's cost of service study and the revenue requirement conclusions that flow from the study, should not be implemented until it has been thoroughly reviewed by ORA.

3. NCGC

NCGC recommends two changes to PG&E's proposed revenue requirement.

The first change is to reduce the customer access charge revenue requirement by approximately $500,000 for 2004. NCGC contends that this change is needed because of the significant slowdown in new power plant service extension requests, which the customer access charge appears to be premised on. As a result, there should be a reduction in PG&E's rate base, which should reduce the customer access charge revenue requirement. NCGC recommends, at a minimum, that PG&E be required to reduce the customer access charge revenue requirement by $0.5 million in 2004 to reflect the revised projection of power plant metering costs contained in the testimony of PG&E's own cost of capital witness.

The second change that NCGC recommends is to remove the cost of non-cycle working gas from PG&E's proposed rate base. PG&E's total working gas is 100.6 MMdth. Of this total, approximately 60 Bcf of this working gas is non-cycle working gas. The capital cost of the 60 Bcf of non-cycle working gas is $80.5 million, which has been included in rate base for 2004.

PG&E is currently earning the short-term interest rate, rather than the utility authorized rate of return, on the non-cycle working gas. PG&E's current estimate of the 2004 short-term interest rate is 2.37%, based on the April 2003 commercial rate forecast. If this estimate were applied to the total $80.5 million, the annual revenue requirement would be $1.9 million, including the cost of franchise fees and uncollectible account expenses associated with the assumed collection of the revenue requirement in rates.

PG&E is proposing in this proceeding to include the $80.5 million in rate base. If rate base treatment were approved, PG&E would be permitted to earn its full allowed return and associated taxes rather than the short-term interest rate on the $80.5 million. The 2004 estimated revenue requirement associated with the $80.5 million of non-cycle working gas in inventory is $10.7 million, based on PG&E's current authorized cost of capital of 9.24% and on current income tax rates of 35% for federal income taxes and 8.84% for state income taxes. This estimated revenue requirement also includes the cost of franchise fees and uncollectible accounts expenses associated with the assumed collection of the revenue requirements in rates.

NCGC asserts that PG&E has not made any showing in this proceeding that the $80.5 million cost of non-cycle working gas should be included in rate base, and there is no testimony supporting a change from the short-term interest rate treatment. Some of PG&E's testimony implied that PG&E would continue to earn only the short-term interest rate on the gas. For example, in its request that PG&E be permitted to sell 4.5 MMdth of the non-cycle working gas, and that it retain all the gain from such a sale, PG&E noted that it had only received the short-term interest rate on the gas. NCGC asserts that it is contradictory for PG&E to propose rate base treatment for non-cycle working gas while simultaneously arguing that it should be permitted to retain the full gain on sale because the gas earns only short-term interest.

NCGC also points out that PG&E earns revenues by loaning non-cycle working gas to customers, which is a hub service. This is also contradictory because it allows PG&E to recover its allowed return on non-cycle working gas while simultaneously recovering incremental revenues by lending the gas to third parties.

Absent a showing that rate base treatment for the non-cycle working gas is appropriate, NCGC contends that PG&E should not be permitted to earn its allowed return and associated taxes on the capital cost of its non-cycle working gas in 2004.

4. Palo Alto

Palo Alto is opposed to the Winter Reliability Standard, and raised concern over the accuracy of the capital expenditures estimate proposed by PG&E for the upgrade of local transmission to meet the 1-in-10 year reliability standard.

Palo Alto concurs with the various recommendations of other parties to adjust PG&E's capital expenditures for the non-cycle working gas, the costs associated with the Gerber Compressor Station, and to reduce power plant metering costs.

5. TURN

The Gerber Compressor Station burned down on November 6, 2001. PG&E replaced the facility, including the gas turbine compressor unit, at a total cost of $35.8 million. The Gerber station was operated remotely from a location over a hundred miles away. The fire was caused by a crack on a nozzle which broke when the unit was starting up, igniting 200 gallons of lubrication oil.

Although TURN has not had time to fully examine all the data and information related to the fire, PG&E's documents raises questions about the cause of the accident, whether the nozzle crack could have been prevented, and whether plant operation practices may have exacerbated the fire.

TURN recommends that the rates covering return, depreciation and taxes on the Gerber station replacement, approximately $6 million, be subject to refund. TURN recommends that a second phase of this proceeding be established to conduct a prudence investigation regarding the cause of the accident that led to the fire, and the operating conditions that allowed the fire to burn down the building.

TURN also points out the potential for a significant insurance recovery, even though PG&E's insurance policy has a deductible of $25 million. TURN recommends that 90% of any insurance recovery be flowed through to ratepayers immediately as a reduction to rate base. The remaining 10% of the insurance recovery should ultimately be used to reduce rate base, but PG&E should be allowed to hold this 10% until the next gas rate case as an incentive to pursue insurance recovery.

6. PG&E

PG&E asserts that is has presented sufficient evidence to support its capital expenditures proposal.

Palo Alto raised concerns over the accuracy of the capital expenditures estimate proposed by PG&E to upgrade its local transmission to meet the 1-in-10 year reliability standard. PG&E demonstrated in its rebuttal testimony that the scope and list of projects did not change from January 16 to March 18, 2003. PG&E merely revised the installed unit cost ($/ft) to reflect current pipeline installation costs.

TURN proposes that the Commission conduct a prudence investigation into the cause of the fire that destroyed the Gerber gas turbine compressor unit. PG&E contends that a prudence investigation is not warranted because its actions at all times, were prudent, and within the applicable laws, regulations and industry standards.

CCC/Calpine claim that the backbone level rate proposal will reduce costs on PG&E's local transmission system by eliminating PG&E's costs of reinforcing local transmission facilities. PG&E says that this argument of CCC/Calpine assumes that every new customer will be physically connected to PG&E's existing local transmission system, which may not be the case.

C. Discussion

1. Introduction

Several parties recommend adjustments be made to PG&E's forecast of capital expenditures for 2004. The five proposed adjustments address the following areas: (1) non-cycle working gas; (2) Pipeline Safety Act; (3) Winter Reliability Standard; (4) reduction in metering costs and power plant costs; and (5) the Gerber Compressor Station.

2. Non-Cycle Working Gas

In just several lines of text in PG&E's prepared testimony, without mention of the rate base amount of $80.5 million,[53] PG&E seeks to change the way in which it is compensated for non-cycle working gas that is used in its storage operations. Instead of earning the short-term interest rate on the non-cycle working gas, PG&E seeks to change the treatment in 2004 to obtain a return on rate base of $80.5 million.

As Mirant points out, this is one reason why careful analysis of the capital expenditures and other costs contained in PG&E's application are required. Although PG&E's request is buried in two places in its text, PG&E does not describe the revenue effect that this change in treatment will have. Had it not been for the cross-examination of PG&E's witness by NCGC's counsel, this issue might have gone unnoticed. Interestingly, PG&E did not comment on the rate base treatment of the non-cycle working gas in either its opening or reply briefs.

NCGC correctly points out that PG&E's position regarding its non-cycle working gas is contradictory. On the one hand, PG&E seeks to sell 4.5 MMDth of non-cycle working gas, for which it says it earned the short-term interest rate on, and to retain all of the proceeds. On the other hand, PG&E seeks to have ratepayers pay PG&E for a rate of return on the same kind of non-cycle working gas. PG&E has not justified why the treatment of its non-cycle working gas should be changed in 2004.

It is appropriate, therefore, to adjust PG&E's forecast of capital expenditures for 2004 by removing the entire $80.5 million of non-cycle working gas from rate base. This adjustment is reflected in Table 2 of Appendix A.

3. Pipeline Safety Act

PG&E expects that the Pipeline Safety Act will result in required assessments of its transmission facilities. PG&E forecasts capital expenditures of $11 million per year starting in 2004 through 2013.

As noted in the O&M section, the work required to comply with the Pipeline Safety Act will occur. However, the deadlines for starting the work do not occur until June and December of 2004.[54] Since we do not anticipate that the major part of the work effort will begin until the second half of 2004, as discussed earlier, it is appropriate to adjust the capital expenditure of $11 million in 2004 to reflect six months of work. That is, the rate base for 2004 should be reduced by $5,500,000. This adjustment is reflected in Table 2 of Appendix A.

4. Winter Reliability Standard

The amount of $2 million has been included in the 2004 forecast of capital expenditures to upgrade the local transmission facilities to meet PG&E's proposed Winter Reliability Standard. PG&E had forecasted that the capital expenditures for the local transmission upgrade project would amount to a total of $42 million for 2004 through 2007.

Since we do not adopt PG&E's proposal for a Winter Reliability Standard, the capital expenditure in 2004 of $2 million is not needed. The $2 million that PG&E forecasted shall be removed from PG&E's forecast of capital expenditures for 2004. This adjustment is reflected in Table 2 of Appendix A.

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[53] *See* Exhibit 3 at pages 12-9 and 14-18, 7 RT 731-737, and 3 RT 259-260.

[54] The December 2004 deadline could be moved up once the Secretary of Transportation issues regulations.

5. Reduction In Metering Costs and Power Plant Connections Costs

In Exhibit 3 at pages 10-8, PG&E testified that:

> "A significant slowdown has occurred in new power plant service extension requests. As a result, cost estimates for MWC 91 are anticipated to drop to $1.5 million and $3.3 million in 2003 and 2004, respectively."

Further down on page 10-8 of Exhibit 3, PG&E notes that "Requests for new business power plant connections have dropped off significantly since mid-2002."

Several of the parties believe that the customer access charge should be reduced because of the reduced number of new power plants. Mirant noted that it was unclear whether the reduction noted at page 10-8 of Exhibit 3 had been incorporated by PG&E. Reading PG&E's testimony at page 10-8 of Exhibit 3 at lines 7 and 8, and 22-23, in conjunction with the cross examination of PG&E's witness, it is clear that a reduction has not been made for Power Plant Metering, MWC-91. In accordance with PG&E's own testimony, the forecast for 2004 for this item should be reduced from $5.1 million to $3.3 million. PG&E shall reduce its forecasted rate base by $1.8 million. This adjustment is reflected in Table 2 of Appendix A.

Since Power Plant Connections are related to new customers coming onto the system,[55] we believe that a similar reduction should be made to the 2004 forecast of Power Plant Connections. Although PG&E's witness testified that the Power Plant Connections reflect the downturn in new power plants, pages 16 and 17 of Exhibit 42 suggest that the amount of $5.4 million may be "a

[55] *See* Exhibit 3 at page 10-7, lines 6-11.

placeholder for speculative new power plant connections." (7 RT 662-663.) Accordingly, the capital expenditure for Power Plant Connections for 2004 shall be reduced from $5.4 million to $3.5 million.[56] This adjustment is reflected in Table 2 of Appendix A.

6. Gerber Compressor Station

PG&E has included in its forecast of 2004 capital expenditures $35.8 million for the Gerber Compressor Station. TURN questions whether this amount should be in rate base at all, but suggests that the 2004 rates include the return, depreciation and taxes on the Gerber Compressor Station, approximately $6 million, and the amount be subject to refund in a separate prudence investigation.

TURN also raised the issue that there may be a significant insurance recovery associated with the fire. Although the deductible on the insurance is $25 million, there may be proceeds from an insurance claim that ratepayers have an interest in.

PG&E contends that no prudency investigation is needed, and that it should be permitted to include the Gerber Compressor Station into rate base. PG&E does not mention the possible insurance recovery in its briefs.

In its comments to the proposed decision at page 9, PG&E stated that after "the close of the evidentiary record in this proceeding, PG&E negotiated a $6 million settlement with its insurers." Attached to PG&E's comments was a declaration by PG&E's Director of its Insurance Department. The declaration states in part that the "insurance proceeds have been credited to the capital order for the Gerber Compressor Station Replacement Project (Order 7041710), thereby

[56] This reduction is based on the 35% percentage reduction for Power Plant Metering.

reducing the total capital cost for that Project." PG&E states that the $35.8 million capital addition for the Gerber replacement "should be revised to $29.8 million, to reflect the $6 million in insurance proceeds, and the final revenue requirement recalculated accordingly, to incorporate the lower rate base amount." (PG&E Comments, p. 9.)

Since PG&E has received this insurance payment, we will adjust the capital expenditure for the Gerber replacement to reflect the receipt of this $6 million payment. This lowers the revenue requirement from what was originally recommended in the proposed decision.

We believe that the insurance recovery issue should be further explored. PG&E has not explained whether it has filed any other claim for insurance, or whether it expects to receive any other insurance proceeds in connection with the fire at the Gerber Compressor Station. The total recovery amount could be as high as $10 million.

In order to determine the status of any remaining insurance claims with respect to the fire at the Gerber Compressor Station, and if so, what should be done with any remaining insurance proceeds, we will order PG&E to file an application within 90 days of today's date to address these insurance claim issues.

We do not adopt TURN's request that a prudency hearing into the Gerber fire be conducted. Since $6 million in insurance proceeds have been received, and are being used to reduce the capital cost of the Gerber Compressor Station, there is no need to adopt TURN's request to establish a memorandum account to track all the revenues that PG&E receives in rates for the Gerber Compressor Station, and all the proceeds PG&E may receive from any associated insurance claims, plus interest, and to make those revenues subject to possible refund to ratepayers. Should the application reveal that additional insurance proceeds are forthcoming, we will explore in that proceeding how those additional proceeds should be applied.

7. Conclusion

We adopt PG&E's forecast of its capital expenditures for 2004, less the adjustments we have made. PG&E shall file its application regarding the Gerber Compressor Station insurance issues.

XI. Cost of Service

A. Summary of Cost of Service

This section addresses the expense and capital revenue requirements that are needed to support PG&E's gas transmission and storage services during the 2004 test year. This cost of service, expressed in terms of a revenue requirement, is used to calculate the 2004 rates. PG&E seeks to recover a revenue requirement of $454 million in 2004 for its gas transmission and storage services.[57] This would recover the $310.5 million in total operating expenses, and provide a rate of return of 9.24% on a rate base of $1.551 billion. The $454 million represents an increase of about 7% over the revenue requirement for 2003 of $424 million.

The current cost structure of PG&E's gas transmission and storage services are based on the Gas Accord Settlement Agreement, and were calculated based on revenue requirement estimates from three sources. The three sources are: (1) PG&E's 1996 GRC decision amounts for the gas department; (2) a specific model to estimate the revenue requirements for Line 401 over its service life; and

[57] Due to the expiration of the Gas Accord Settlement Agreement, and the one-year extension agreed to in D.02-08-070, the revenue requirement for PG&E's gas transmission and storage systems will require future annual reviews, unless otherwise directed.

(3) specific calculations of the revenue requirements associated with required NOx-related capital additions.

PG&E's O&M expenses for 2004 include labor, materials, supplies, contracts, and other related expenses for operating and maintaining the gas transmission and storage facilities and to provide customer service. PG&E's estimate of operating expenses for 2004, which includes O&M and A&G expenses, are $149.966 million, as shown in Table 12.2 of Exhibit 3.

PG&E's A&G expenses, and the amount of A&G expenses to be allocated to gas transmission and storage, are being addressed in PG&E's 2003 test year GRC. Since a decision in the 2003 GRC is not expected until late 2003, PG&E is proposing in this proceeding that the A&G expenses for the 2004 gas structure revenue requirement be a placeholder only, and subject to update with the results of the GRC. The placeholder amount for A&G expenses is $53.130 million, and is shown in Table 12-2 under operating expenses. Once the 2003 GRC decision determines the portion of A&G expenses that should be assigned to gas transmission and storage, the 2004 gas structure rates would be updated with the GRC-adopted amount.

In the event that PG&E's 2003 GRC decision is not available in time to reflect the GRC A&G amount in the 2004 rates by January 1, 2004, PG&E proposes that the Commission approve the creation of a memorandum account in which the A&G difference between the adopted revenue requirements from the 2003 GRC, plus escalation to 2004, and the placeholder used in the 2004 gas structure revenue requirement be tracked with interest. The balance in the memorandum account would be incorporated directly in the gas transmission and storage rates by an advice letter filing.

PG&E's estimate of taxes include state and federal income taxes, property taxes, payroll taxes, business taxes, and other taxes. PG&E estimates 2004 taxes of $81.413 million as shown in Table 12-2 of Exhibit 3. PG&E's calculation of the federal income tax and the California Corporation Franchise Tax are reflected in detail in Table 12-5 of Exhibit 3.

PG&E's estimate of depreciation expense for the 2004 gas structure revenue requirement is $79.143 million, as shown in Table 12-2 of Exhibit 3.

PG&E's estimates of plant and rate base for the 2004 gas structure revenue requirement are reflected in Tables 12-2 and 12-4 of Exhibit 3. PG&E's estimate of rate base for the 2004 revenue requirement for its gas transmission and storage system is $1.551 billion. This rate base estimate includes the addition of $80.5 million of non-cycle working gas in storage into rate base. At the present time, the PG&E receives the short-term interest rate for this gas through the procurement component in the BCAP.

B. Discussion

Many of the arguments pertaining to PG&E's cost of service were addressed earlier in Section III.B. Some of the parties advocated that 2003 rates be extended into 2004, or that PG&E's cost of service for its transmission and storage systems be addressed in other proceedings.

We allowed PG&E to submit a cost of service study in this proceeding, and directed parties to provide testimony on what the gas market structure should be for 2004, and what rates should apply. This is the appropriate proceeding in which to address PG&E's cost of providing transmission and storage services to its customers, and to develop a revenue requirement and rates to recover those costs. Although time and resource constraints prevented ORA and others from conducting a thorough review of PG&E's application, we are obligated to adopt a revenue requirement and rates in 2004.

Based on the proposals adopted in this decision, the adjustments[58] made to PG&E's forecast of O&M expenses and to its forecast of capital expenditures, we adopt a total revenue requirement of $436,397,000 for PG&E's gas transmission and storage systems for 2004. This revenue requirement may be affected by the A&G costs that are being addressed in PG&E's 2003 GRC, escalated to 2004.[59] We expect to act on that decision in the near future. Today's adopted revenue requirement may also be affected in the future by the 2004 cost of capital proceeding.

Our adopted revenue requirement is set forth in Table 1 and Table 2 of Appendix A, and illustrates the differences between 2003 rates, PG&E's revenue requirement request, and our adopted revenue requirement amount.

PG&E shall establish its 2004 transmission and storage services rates and charges based upon our adopted revenue requirement, and the adopted proposals that affect the allocation of costs, and the design of rates.

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[58] As noted earlier, the adjustments to O&M expenses and to capital expenditures are based on our calculation of the revenue requirement effects. Should the revenue requirement effects vary from our calculation of the effect of the adjustments, the adopted revenue requirement is the amount upon which rates are to be calculated.

[59] The Contingency Rate Adjustment section addresses PG&E's request for a memorandum account to track the difference between the A&G placeholder in this decision, and the actual A&G costs, escalated to 2004, that is to be addressed in PG&E's GRC.

XII. Demand Forecast

A. Summary of Demand Forecast

The demand forecast addresses PG&E's forecast of on-system demand, off-system deliveries, and total throughput for the 2004 period. This annual demand forecast is then used for cost allocation and ratemaking purposes. For 2004, PG&E forecasts total throughput of 2273 MDth/d, or on-system demand of 2054 MDth/d[60] and 219 MDth/d of off-system delivery. This is shown in Table 13-1 of Exhibit 1.

There are four main market segments that make-up on-system end-use demand. These four segments are core, noncore industrial, electric generation, and wholesale. The core is composed of mainly residential and commercial customers. The noncore industrial consists of large customers who are engaged in industrial activities and who qualify for service under the G-NT rate schedule, and noncore natural gas vehicle customers. The electric generation segment consists of generators and cogeneration facilities that use natural gas to make electricity. The wholesale segment consists of municipal or private entities that purchase transportation-only service for gas for resale through non-PG&E distribution systems.

PG&E's 2004 forecast of demand for these four market segments are as follows in MDth/d: core – 800; noncore industrial – 450; wholesale – 11; electric generation and cogeneration – 745. PG&E notes that on-system demand has declined about 3.6% per year over the 2001-2004 period.

PG&E's electric generation demand forecast assumes that the decline in electric generation demand from 2001 to 2002 is likely to continue through 2004

[60] The 2054 MDth/d figure includes 48 MDth/d of shrinkage and exchange.

because new combined cycle plants[61] will be added much faster than the growth in electricity demand. Since these newer plants are more efficient, gas usage should decrease.

Various parties have raised the issue of whether the electric generation demand forecast should be revised due to the lower number of gas-fired combined cycle power plants that are expected to be built. Due to the lower number of new plants, some parties contend that this will result in an increase of gas consumption at the less-efficient gas-fired generating plants, which should raise the electric generation demand forecast. PG&E asserts that if the electric generation demand forecast is updated, other forecasts should be updated as well.

The off-system delivery forecast is for gas that is transported through PG&E's backbone transmission system and delivered to SoCalGas' transmission system for final delivery to customers in the Southern California market. These off-system customers are generally looking to buy gas that is produced in Canada or in Northern California. Some of these off-system customers have firm G-XF contracts for Redwood path capacity that were signed when Line 401 was built. PG&E forecasts 2004 off-system demand of 219 MDth/d.

PG&E proposes to adjust the backbone throughput to account for the fact that some backbone contracts have a rate higher than the annual firm rate[62] and some contracts have a lower rate. The annual firm rate is increased by 20% to determine the seasonal firm rate and the as-available rate. In order to account for

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[61] PG&E notes that the new combined cycle power plants use 25 to 50% less natural gas than steam turbine plants to produce the same amount of electricity.

[62] PG&E's load factor of 68.4% is used to determine the annual firm rate.

the higher revenues from the seasonal and as-available service and lower revenues from discounted contracts, the backbone load factor adjustment is added to the forecast of throughput prior to calculating the load factor. The backbone load factor adjustment is the amount of throughput paying the higher rate multiplied by the percentage over the annual rate, less the throughput paying a lower rate multiplied by the percentage over the annual rate, less the throughput paying a lower rate multiplied by the percentage discount to the annual rate. PG&E estimates that the net increase to backbone throughput is 45.9 MDth/d.

B. Position of the Parties

1. CCC/Calpine

CCC/Calpine assert that PG&E has materially understated its proposed 2004 electric generation (EG) throughput forecast. The Commission should instead adopt CCC/Calpine witness Beach's proposed EG throughput forecast of 665 MDth per day.

PG&E forecasted gas demand for electric generation by using the MarketBuilder model of the Western Electricity Coordinating Council (WECC) electricity market in 2004, assuming average hydro conditions and all known new resources expected to come on line before or during the forecast period. CCC/Calpine note that all of the parties who took a position on the throughput forecasts, except for PG&E, agree that PG&E's electric generation throughput forecast is too low.

Beach mentioned several factors why PG&E underforecasted EG gas demand. The first factor is because EG gas demand increases more in a dry year than it decreases in a year that is comparably wet. CCC/Calpine assert that because EG throughput in wet years does not decline symmetrically with increases in EG throughput during dry years, use of average throughput systematically biases throughput forecasts downward.

The second factor is that new resource additions, *i.e.* renewables, cogeneration, more efficient combined cycle plants, and demand-side management, tend to reduce gas demand for electric generation. Although PG&E used a relatively up to date list of new resources and on-line dates, there has been significant slippage in the on-line dates for many of these projects. These delays will remove 4,531 MW of new resources that PG&E's model assumed would be available in 2004. This represents 71% of the 6,355 MW of new generation in the WECC that PG&E expected to come on line in 2004, as listed in Table 13-4 of Exhibit 1. NCGC had asked PG&E to rerun its model under the assumption that 100% of PG&E's assumed new resources are delayed by one year. This sensitivity run resulted in a 14% increase in EG demand in 2004.

CCC/Calpine assert that since the record in this case shows that known delays in new plant completions already exceed 70% of the delay that PG&E itself modeled in the sensitivity run for NCGC, new plant delays can be expected to raise PG&E's EG loads in 2004 by 10% (71% of 14%) above the levels shown in PG&E's forecast.

Beach's testimony shows that PG&E's reliance on average hydro conditions has resulted in 10% to 12% under-forecasts of actual EG demand. The combination of the known plant delays, PG&E's own sensitivity run on the impact of a one-year delay in new plants, and the under-forecasts due to reliance on average hydro conditions, all support Beach's EG throughput forecast of an additional 15% in EG demand. For these reasons, CCC/Calpine recommend that the Commission adopt a 2004 EG demand forecast of 665 MDth per day.

PG&E contends that if the forecasting model is to be updated, that all elements of the model be updated rather than just selected inputs. CCC/Calpine assert that PG&E has the opportunity to present a forecast, and that parties responded. The Commission should not allow PG&E to redo all of its modeling assumptions. Instead, the Commission should decide this issue based on the record that has been developed concerning PG&E's forecasts, other parties' analyses of those forecasts, and the utility's responses to those critiques.

CCC/Calpine also assert that PG&E understated its forecast of off-system backbone level throughput. PG&E contends that off-system backbone level throughput will decrease below the historical level of 298 MDth per day experienced during the original Gas Accord period. PG&E proposes the following downward adjustments to historical off-system throughput: (1) reduce G-XF contract volumes by 35 MDth/day; and (2) reduce Baja off-system flows by 44 MDth/d.

CCC/Calpine contend that both of PG&E's adjustments are incorrect. PG&E's adjustment for G-XF volumes is attributable to the expiration of certain existing G-XF contracts. Although CCC/Calpine do not dispute that off-system G-XF volumes may have expired, this does not necessarily translate into an overall reduction in off-system throughput. CCC/Calpine contend that it does not follow that because certain G-XF contracts are terminating, that they will not utilize short-term off system service, which is what PG&E assumes.

CCC/Calpine assert that the demand for off-system service does not depend on whether some customers are signing or terminating long-term contracts for such service. What matters is whether there is an economic incentive to take off-system service, on either a short or long term basis. If the price for and supply of off-system service are at least as high as in the past, then the demand for the service should also be as robust as it has been historically. Thus, it is reasonable to forecast that the demand for Redwood off-system service in 2004 will at least reach historical levels.

With respect to demand for Baja off-system service, PG&E asserts that this will shrink to zero. However, the demand for Baja off-system service is driven by the spread in prices at Topock between gas going into the PG&E system, and gas flowing into the SoCalGas system. PG&E witness Wilson recognizes that the price spread at Topock is the result of capacity constraints moving gas onto the SoCalGas system, which result in a much higher Topock into SoCalGas price. CCC/Calpine assert that these constraints will not change in 2004 compared to 2002. Thus, the price spreads at Topock should persist, resulting in similar levels of Baja off-system throughput to those experienced in the past.

CCC/Calpine recommend that PG&E's forecast of off-system demand be revised upwards to levels consistent with historical experience. That is, an off-system throughput forecast of 298 MDth/d should be adopted.

2. CMTA

CMTA contends that PG&E's proposed backbone rates are based on a gas throughput forecast which is too low. CMTA contends that PG&E understated the throughput by underestimating forecasted gas demand by electric generators, and by using off-system throughput that falls below historical levels.

PG&E assumes that Redwood off-system throughput will decrease. However, this is contrary to PG&E's own observation that demand for Redwood off-system service is likely to remain at historic levels, due to the expected continuation of the historic $0.21 per Dth price spread between Malin and Topock. CMTA contends that it is this price spread, and not the G-XF contract volumes as PG&E assumes, that drives demand in the transportation market.

PG&E acknowledges that price spreads drive market demand in its Market Builder model that is used to forecast EG throughput.

3. Duke

Duke recommends that the key elements of PG&E's forecast of EG gas demand be updated to reflect the cancellation and deferral of planned new generation units. Duke points out that PG&E's forecast was developed when many new efficient plants were expected to come on-line in 2003 and 2004. PG&E's EG throughput forecast relied on a list of expected power plant additions that the California Energy Commission (CEC) issued in July 2002, and a similar list prepared by WECC in January 2002. It was expected that these more efficient plants would displace less efficient, older gas-fired plants and, as a result, EG gas throughput would decline.

PG&E forecasted that EG throughput would decrease by 18% in 2004. Since the time PG&E's forecast was made, many plant sponsors have cancelled or deferred their proposed new plants. Duke believes the Commission should have a forecast that reflects the most recent available list of expected power plant additions because of the effect these cancellations will have on the EG demand forecast.

4. Mirant

Mirant notes that it would be prudent for the Commission to consider and take official notice of the most current forecasts of power plant construction and new power plant additions, as those forecasts may affect PG&E's EG gas demand forecasts for 2003 and 2004.

5. NCGC

NCGC witness Pretto testified that the EG throughput forecasted by the MarketBuilder model that PG&E used is sensitive to assumptions about whether or not projected new power plants will come online. PG&E's forecast of EG usage in 2004 is 580 Mdth/d. NCGC asserts that due to plant deferrals and cancellations, 2004 EG throughput could easily be higher because those deferred or cancelled plants are more efficient. If less efficient plants inside PG&E's service territory are utilized at higher load factors, the result could be increased throughput to EG customers.

PG&E provided a sensitivity analysis to the NCGC witness about the impact of plant cancellations or deferrals on PG&E's EG throughput forecast. According to NCGC, the analysis showed that if the plants listed in Table 13-4 of Exhibit 1 were delayed by one year, 2004 EG throughput would be 663 Mdth/d, 14% higher than forecasted by PG&E. If the plants were delayed by two years, the 2004 EG throughput would be 791 Mdth/d or 36% higher than forecasted by PG&E. NCGC asserts that these results illustrate that PG&E's projected EG throughput is highly sensitive to the operative dates of the plants listed in Table 13-4 of Exhibit 1. Due to the sensitivity, NCGC recommends that PG&E's EG throughput forecast be updated as near as possible to the issuance of a final decision in this proceeding to reflect the status of new power plants at that time.

NCGC contends that it would be easy to accomplish an update of PG&E's proposed EG throughput forecast. The CEC uses a version of the MarketBuilder model called the North American Regional Gas Model (NARG). Using NARG, the CEC is developing a new forecast of EG throughput. The CEC's throughput forecast was scheduled to be released on May 23, 2003. Due to the similarities between the two models, the CEC's forecast should be used to update PG&E's EG throughput forecast.

Instead of updating the EG throughput to consider just actual plant additions, PG&E urges a comprehensive update, using the most recent information from the same data sources that were used in the prepared testimony. NCGC asserts that a comprehensive update is unnecessary. If a comprehensive update of PG&E's throughput forecast is done, NCGC recommends that it focus on EG throughput, off-system backbone throughput, and as-available backbone throughput. The as-available backbone throughput should take into account the most recent available information on the mix of backbone services, i.e., firm service and as-available service, that shippers are taking on the PG&E system today.

6. TURN

TURN disputes PG&E's forecast of 745 Mdth/d of load for electric generation. TURN contends that PG&E's forecast underestimates electric generation throughput by assuming that 56,000 MW of new combined cycle generation will come online in 2004 throughout the western United States.

TURN witness Marcus disagrees with PG&E's throughput estimate for EG demand. PG&E's projected decline in EG throughput from 2001 to 2004 presumes the construction and availability of numerous out-of-state combined cycle power plants, many of which have been cancelled. TURN has identified over 4500 MW of generation that has been cancelled or delayed. Marcus also noted that 2004 is likely to be the lowest year for EG gas demand in California in the next few years. Marcus suggests basing the EG demand estimate on several future years, rather than PG&E's depressed and likely inaccurate projection for 2004.

TURN recommends that the Commission require PG&E to rerun its EG forecast with more recent information regarding project cancellations and delays, and report the results for 2004-2007.

7. PG&E

PG&E developed forecasts of on-system demand, off-system deliveries, and total throughput for the Gas Accord II 2004 period. These forecasts are used for cost allocation and ratemaking purposes. PG&E asserts that its forecasts are based on careful analysis and are consistent with historical experience and anticipated future conditions.

PG&E points out that since no party took issue with PG&E's proposed core and noncore industrial forecast, the Commission should adopt PG&E's proposed core and noncore industrial forecast for 2004.

PG&E's forecast of gas demand by all cogeneration plants except Crockett was uncontested. PG&E contends that because the output and gas demand of cogeneration plants, except Crockett, are not strongly affected by conditions in the electricity market, its forecast was based on an extrapolation of recorded data. Since no one disputes PG&E's cogeneration forecast, PG&E recommends that its cogeneration forecast be adopted.

PG&E also presented a forecast of gas demand for gas fired EG plants whose production levels are affected by changes in the electricity market. PG&E asserts that its forecast is based on a detailed modeling of the power markets, and should be adopted. PG&E's EG forecast was based on the most current data and assumptions, and no changes to its forecast are needed. However, if the Commission is inclined to have PG&E perform an update to its demand forecasts, PG&E recommends that all input assumptions, and all components of the demand forecast (core, noncore, EG, off-system) be reevaluated. PG&E notes that a selective or piecemeal update would result in a biased forecast that is based on internally inconsistent assumptions.

PG&E points out that the intervenors propose using a higher estimate of EG gas demand because that would lead to lower rates. The CCC/Calpine proposes to raise PG&E's EG forecast by 15 percent because of an alleged average understatement of PG&E's EG demand forecast from prior years. PG&E points out that CCC/Calpine's proposed 15% increase is based on the assertion that hydro conditions in 2004 will be biased toward dry conditions. However, hydro conditions for 2003 are forecasted to be close to average.

PG&E also contends that the accuracy of PG&E's prior EG forecasts are not relevant because it is using a new forecasting method, the MarketBuilder model. PG&E asserts that the evidence demonstrates that this model has not underestimated average EG gas demand.

CAPP contends that PG&E's forecasted load factor of 68.4% for 2004 is too low compared to third party forecasts, such as the CEC, which projected a system utilization for PG&E at 75%. PG&E says this argument is without merit because the CEC forecast of December 2002, which CAPP relied on, was to be corrected and updated in Spring 2003. PG&E says this update was posted on May 28, 2003 on the CEC's website. Figure 14 of that CEC document shows that the CEC's forecast of gas demand for electricity generation (including cogeneration) in 2004 is about 750 MMCF/day or 760 MDth/d. The CEC's new forecast is lower than PG&E's which was 845 MDth/d (580 MDth/d for EG as PG&E defines it and 265 MDth/d for cogeneration). Although the CEC forecast is lower than PG&E's, PG&E is not recommending that it be adopted because it is a preliminary staff forecast not adopted by the CEC, and may be based on a different model.

CCC/Calpine argue that new plant delays alone can be expected to raise PG&E's EG loads in 2004 by 10% above the levels shown in PG&E's EG forecast, and that the Commission should not allow PG&E to re-do all of its modeling assumptions. PG&E asserts that forecasts of electricity demand affect both the schedules of power plant development and EG gas demand forecasts, and the record shows that EG forecasts are sensitive to electricity demand. PG&E says it is only fair that if power plant schedules are to be updated, electricity demand forecasts should also be updated.

Mirant says that Beach pointed out the extent to which PG&E's past EG forecasts using similar models have underestimated actual EG demand. But PG&E says nothing in the record or in fact supports Mirant's claim that PG&E's current EG forecast and its past forecasts were developed using similar models. There is nothing in the record about what models, if any, were used previously by PG&E or how they might be similar to Marketbuilder.

TURN claims that PG&E's forecast underestimates electric generation throughput by assuming that 56,000 MW of new combined cycle generation will come online in 2004 throughout the western United States. PG&E says TURN is incorrect because PG&E's forecast never assumed that 56,000 MW would come on-line, and that it did not use the WECC forecast.

PG&E's forecast of its off-system throughput is the sum of the following: the short-term Baja off-system contracts; the short-term Redwood off-system contracts, and the long-term Redwood off-system contracts. CCC/Calpine contend that PG&E's off-system forecast is too low, and recommends a higher forecast of 298 MDth/d based on the average off-system flow since the beginning of the Gas Accord period. PG&E contends that its off-system forecast is reasonable and should be adopted. PG&E asserts there is no evidence in the record that these terminating G-XF customers will continue to use off-system service.

PG&E points out that TURN proposes that PG&E provide EG throughput forecasts for 2005 to 2007. PG&E does not believe such a forecast is needed to set rates for 2004, and TURN's proposal should be rejected.

C. Discussion

The only demand forecasts that parties take issue with are the EG forecast, and the off-system forecast. These two forecasts affect the throughput amount which is used to calculate the system load factor, which in turn is used to develop rates. A higher demand forecast, all else being equal, will result in a higher system load factor. A lower demand forecast, all else being equal, will result in a lower system load factor. The higher the load factor, the lower the rates will be, because there will be more throughput to allocate the costs. The lower the load factor, the higher the rates will be, because there will be less throughput to allocate the costs.

We turn first to the EG demand forecast. The record has many references to the reduction in the number of new gas-fired EG plants. Some of the parties favor an update of the EG forecast in light of the downturn in new plants, while PG&E favors a comprehensive update of all the relevant variables. We do not believe that an update is needed in light of the record, and updating the forecast at this point would be impractical given the time constraint.

The sensitivity runs that PG&E ran for NCGC show that if the plants listed in Exhibit 1 were delayed by one year, 2004 EG throughput would be 14% higher, or using PG&E's EG forecast, to 663 MDth/d. If the plants were delayed by two years, 2004 EG throughput would be 36% higher, or 791 MDth/d. CCC/Calpine's testimony suggests a 15% increase, which is slightly higher than the one-year sensitivity run.

The record also referred to the CEC's forecast that is part of the integrated energy policy report that was to go to the Governor on November 1, 2003. (8 RT 789.) An earlier version of the forecast was cited by PG&E in its brief, and the latest version of that staff report is dated August 2003 and is entitled "Natural Gas Market Assessment." In Figure 14 at page 46 of that report, the forecast of average daily demand for gas in PG&E's service territory by electricity generation (including cogeneration) for 2004 appears to range from 800 to 900 MDth/d.[63] This provides a useful comparison to PG&E's combined forecast EG and cogeneration forecast of 845 MDth/d.[64] Using the one year sensitivity analysis, a 14% increase of PG&E's EG forecast would result in an increase of 81.2 MDth/d or a total combined EG and cogeneration forecast of 926.2 MDth/d. Based on this information, we will not change PG&E's electric generation and cogeneration forecast.

The next forecast to address is PG&E's off-system delivery forecast of 219 MDth/d. PG&E's forecast of this amount is challenged by CCC/Calpine. CCC/Calpine recommend that the recorded off-system throughput of 298 MDth per day during the Gas Accord period be used instead.

We adopt CCC/Calpine's forecast of off-system throughput. Our reasoning is that PG&E is requesting as part of this proceeding that it be permitted to allow eligible off-system end users to connect directly to PG&E's backbone transmission service. One of the reasons that PG&E gives in support of

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[63] Pursuant to Rule 73 of the Commission's Rules of Practice and Procedure, we take official notice of the CEC's report.

[64] It is unclear from Figure 14 of the CEC's report whether the gas supplied to plants through private pipelines are included in this average daily demand.

that proposal is that "Customers outside PG&E's service territory have expressed interest in taking service from PG&E's backbone system…." (Ex. 1, p. 18-6.) As discussed later in this decision, we approve that request. Once this service is in place, off-system throughput should remain at recorded levels or increase, and in the words of PG&E would "enhance the use of PG&E's backbone transmission system." (Ex. 1, p. 18-8.) Accordingly, PG&E shall use the 298 MDth/d in its 2004 demand and throughput forecast for off-system delivery, and in the calculation of its load factor.

No one has raised objections to the other forecasts of demand that are shown in Table 13-1 of Exhibit 1, or to the backbone load factor adjustment..

We adopt the forecasts of demand and throughput and the backbone load factor adjustment that are shown in Table 13-1 of Exhibit 1, as modified by the increase to off-system delivery.

XIII. Cost Allocation and Rate Design

A. Summary

This section addresses PG&E's cost allocation and rate design proposals for backbone transmission, local transmission, storage, and transmission-level customer access charges. It also addresses the backbone level rate proposal, and the segmentation of the electric generation class.

PG&E proposes to maintain the current Gas Accord cost allocation and rate design structure for 2004, as extended by D.02-08-070, along with PG&E's proposed changes to the current cost allocation and rate design. PG&E's proposed rates are set forth in Appendix 14-1 of Exhibit 3 (Tables 14.1-1 through 14.1-13), and are summarized in illustrative class average rates in Table 14-1 of Exhibit 3. PG&E's proposed rates for 2004 assume the adoption of PG&E's

backbone, local transmission, transmission-level customer access, and storage rate proposals.

PG&E's bundled core customers pay backbone transmission and storage costs as part of their core procurement rate. Gas ESPs, noncore customers, and shippers delivering on and off-system, pay backbone charges and optional storage services separately to CGT. Local transmission and transmission-level customer access charges are included in core and noncore end-user transportation rates.

The end-user rate components such as distribution, and customer class components (*e.g.,* public purpose programs, forecast period costs, and balancing accounts), are set in the GRC, BCAP, annual true-ups of balancing accounts, and other regulatory and legislative proceedings.

The issues regarding cost allocation and rate design center around the concerns of some customers that rates should reflect the costs of the facilities used to provide the services, without additional cost subsidies. Other parties have expressed concern over the cost-shifting effects of the various proposals. In addition, the threat of competitive bypass from proposed pipeline construction projects has resulted in proposals that seek to address the bypass issue.

1. Backbone Transmission Cost Allocation and Rate Design

a. Gas Accord Period

(1) Cost of Service and Cost Allocation

The Gas Accord established a separate unbundled backbone transmission service for firm and as-available on-system and off-system transportation. The initial cost of service was based on the 1996 GRC-adopted based revenues, excluding Line 401. (73 CPUC2d at 820.) Line 401 costs were based on the initial

$736 million pipeline expansion project cost that was approved in D.94-02-042. (73 CPUC2d at 820.)

For the Gas Accord, the costs were allocated to the various backbone service paths using the embedded costs of the facilities. For Line 400, costs were maintained on a separate vintage basis from Line 401 costs. Other backbone costs were allocated to each path based on a pro rata share of the firm design capacities of each path. (73 CPUC2d at 819-820.) Table 14-3 of Exhibit 3 shows the firm design capacities that were used to allocate the costs of the backbone to the various backbone paths during the Gas Accord.

The load factor used to set the backbone rates in the Gas Accord was 87.5%. Incremental Line 401 (Schedule G-XF) Redwood Path rates were designed using a load factor of 95%. (73 CPUC2d at 821.)

(2) Rate Design

In the Gas Accord, core Redwood Path rates were based on vintage Line 400 cost of service. Noncore on-system Redwood Path rates were based on Line 400 and on a phase-in of between 203 and 380.6 MDth/d of Line 401 cost of service. Off-system Redwood Path rates were based on the incremental Line 401 cost of service and rates. (73 CPUC2d at 820.)

The rate design for the Silverado Path on-system was based on a partial allocation of costs from all backbone transmission paths and the common backbone component. The Silverado off-system rate was equal to the Line 401 off-system rate since it assumes Line 401 is used to provide the service. (73 CPUC2d at 820.)

The Gas Accord also established two-part (reservation and usage) firm annual rates under modified fixed variable (MFV) and straight fixed variable (SFV) rate design options. Seasonal two-part MFV and SFV rate options and volumetric as-available rates were designed based on 120% of the firm annual rate. (73 CPUC2d at 802, 841-845, 848.)

The Gas Accord also honored pre-existing contracts such as G-XF contracts. (73 CPUC2d at 800, 815-818.)

The Gas Accord backbone rates escalated at 2.5% annually, except for Line 401, which was accounted for in accordance with D.94-02-042, and except for certain agreed-upon Line 300 revenue requirements associated with the $42 million of NOx-related retrofits which were added to the Line 300 escalated revenues. Backbone rates were guaranteed through 2002, subject to z-factor adjustments. (73 CPUC2d at 822.) D.02-08-070 extended the 2002 rates through 2003.

b. 2004 Cost Allocation and Rate Design Proposal

PG&E proposes to continue the basic cost allocation and rate design structure of the Gas Accord[65] with the modifications described below.

PG&E proposes a partial roll-in of the core Redwood Path vintage rate design. Under PG&E's proposal, core vintage Line 400 Redwood Path rates will be 20% rolled-in with noncore Redwood Path costs for 2004. According to PG&E, a partial 20% roll-in of the costs for the two lines would establish a Redwood Path rate that more closely reflects the way the services are used today while managing core customers concerns for rate stability.

PG&E proposes to design on-system Redwood Path rates using all available Redwood Path firm capacity that is not contracted for under

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[65] This includes being at risk for throughput and revenues on the backbone transmission system. (*See* 73 CPUC2d at 821, Balancing Account Treatment; Ex. 3 at 14-15.)

Schedule G-XF, including the Line 401 expansion capacity. Under the Gas Accord, on-system (non-vintage) Redwood Path rates were designed using only 380.6 MDth/d of Line 401 capacity. (*See* Ex. 3, p. 14-9, Table 14-3.) PG&E contends that this proposed design of the Redwood Path rates is justified due to the historical and expected future use of Line 401 for on-system deliveries. Since all Redwood Path capacity will be used to design on-system rates, PG&E proposes that the Redwood Path off-system rate be set to equal the on-system rate.

Table 14.4 of Exhibit 3 summarizes the firm design capacity of the various backbone paths that PG&E proposes be used to allocate costs. That table is reproduced below in Table 5.[66]

Table 5

Rate Path	Line 400/2	Line 401	Line 300	Gathering	Total
Redwood Vintage	615.5				615.5
Redwood	405.6	870.1			1,281.1
Baja			1,101.3		1,101.3
Silverado				197.4	197.4
Mission					
Subtotal	1,021.1	870.1	1,101.3	197.4	3,195.3
G-XF Contracts		91.8			
Total	1,021.1	961.9	1,101.3	197.4	3,195.3

PG&E proposes in Table 14-5 of Exhibit 3 to assign the vintage Redwood Path capacity total of 615.5 MDth/d to core retail and core wholesale customers as follows: core retail – 609; Alpine – 0.087; Coalinga – 0.609; Island Energy – 0.072; Palo Alto – 5.433; West Coast Gas (WCG) Castle – 0.072; WCG Mather –

[66] The capacity sold to SMUD has been excluded from Table 5.

0.227. The Gas Accord provides that capacity of up to 6.6 MDth/d is available on the Redwood Path for existing wholesale customers on behalf of their core load. (73 CPUC2d 808.)

PG&E's assignment of capacity to the core for non-vintage Redwood Path and Baja backbone capacity is to meet core customers' 1-in-10 year demand requirements, as proposed by PG&E.

Approximately 86.4 MDth/d of off-system and 5.4 MDth/d of on-system Line 401 capacity is contracted for under Schedule G-XF. G-XF rates will continue to be designed on an incremental basis, in accordance with D.94-02-042.

PG&E proposes in 2004 to design backbone rates using a system average load factor of 68.4%. This load factor is calculated by dividing the adjusted 2004 demand forecast (2184.926) by the net firm design capacity (3195.292), as shown in Table 14-6 of Exhibit 3. PG&E states that this lower load factor reflects the recent changes in gas and electric demand, in particular, conservation efforts and a slower economy. Since PG&E proposes to be at-risk for throughput and revenues on its backbone transmission system, the load factor of 68.4% provides PG&E with a reasonable opportunity to recover its backbone cost of service.

PG&E's backbone rates are contained in Appendix 14-1 of Exhibit 3, in Tables 14.1-3 through 14.1-9. These backbone rates are subject to PG&E's proposed contingency rate adjustment, as discussed later in this decision.

2. Storage Cost Allocation and Rate Design

a. Gas Accord Period

PG&E's storage facilities were primarily built to provide core reliability. For the first year of the Gas accord, approximately $5 million of storage costs were allocated to the load balancing service. The remaining storage cost of service was allocated 87.5% to the core and 12.5% to market storage services based on the pro rata share of inventory capacity assigned to each service.

Storage costs allocated to the core were initially bundled in all core transportation rates. The Gas OII Settlement Agreement in D.00-05-049 unbundled storage costs from core transportation rates, and offered pro rata shares of Core Firm Storage capacity to CPGs. Currently, PG&E's Core Procurement Department recovers the cost of its pro rata share of Core Firm Storage capacity in bundled core procurement rates. Gas ESPs serving core customers are offered a pro rata share of Core Firm Storage capacity with an option to reject a portion of their storage assignment. Gas ESPs pay a monthly storage charge under Schedule G-CFS – Core Firm Storage, based on their quantity of assigned storage.

Storage costs allocated to pipeline load balancing are bundled in all backbone transmission rates. A new self-balancing service option was established in the Gas OII Settlement Agreement. Customers or balancing agents who elect self-balancing on a daily basis can opt out of PG&E's monthly balancing program and receive a $0.005 per Dth credit from PG&E. If they elect to self-balance, their share of the balancing storage costs and capacity are assigned to CGT's market storage services.

The storage costs allocated to CGT's market storage services are used to set rates for firm, negotiable, and as-available storage, and parking and lending services. Rates for the market storage services are based on the costs of storage injection, inventory, and withdrawal. Firm storage rates include a capacity (injection and inventory) and a withdrawal reservation charge and volumetric rate. The fixed capacity and withdrawal costs are recovered through the reservation charges, and the variable capacity and withdrawal costs are recovered through volumetric rates.

Negotiated firm and as-available services are negotiable above a price floor representing PG&E's short-run marginal cost of providing the service and under a ceiling representing 100% of the cost of service. Negotiated firm rates may be one-part volumetric or two-part reservation and volumetric. Negotiated as-available storage injection and withdrawal rates are recovered through a volumetric rate only.

Parking and lending services are negotiated under a cost-based maximum charge. The maximum charge is based on the annual cost of cycling one decatherm of firm storage gas assuming a 214-day injection season (April 1-October 31) and 151-day withdrawal (November 1-March 31) season.

b. 2004 Proposals

(1) Introduction

PG&E proposes only minor refinements to the cost allocation and rate design structure for storage-related costs as established in the Gas Accord, refined in the Gas OII Settlement Agreement (D.00-05-049), and as extended for 2003 in D.02-08-070. Storage costs will be allocated to storage subfunctions based on each subfunctions' annual injection, inventory and withdrawal cycling capacity. In addition to storage base revenues, gas and electric shrinkage costs are included in the total storage cost of service.

As part of the storage cost of service for 2004, PG&E has included the long-term costs of financing non-cycle working gas into rate base. According to PG&E, it is currently receiving the short-term interest rate on non-cycle working gas. For 2004, $80.5 million has been included in rate base for this purpose.

PG&E forecasts $63.6 million in storage costs for 2004. This storage cost of service will be allocated to the storage services (core firm, standard firm, and monthly balancing) based on their pro rata share of annual injection, inventory and withdrawal cycling capacity assigned to each service. Tables 14-8 and 14-9 of Exhibit 3 shows PG&E's assignments of storage capacities to each storage service for 2004, and the proposed allocation of storage costs to each storage service.

(2) Core Firm Storage Service

The Core Firm Storage rate will continue to be designed as a single monthly capacity charge based on the cost of core storage service.
Schedule G-CFS will apply to gas ESPs and CPGs, including PG&E's Core Procurement Department, as discussed in the section on storage. The gas storage shrinkage has been unbundled from the backbone shrinkage factor, and will be applied Core Firm Storage injections.

(3) Standard Firm Storage and Market Storage Services

PG&E proposes to simplify the firm standard storage rate design by combining the capacity and withdrawal reservation and usage charges into a single capacity charge. PG&E states that this rate design will better reflect the way in which capacity rights are provided to customers.

Core wholesale customers will have a one-time option to subscribe to Standard Firm Storage capacity. The wholesale customer must notify PG&E in writing prior to the 2004 storage open season. They will receive first priority from the storage capacity allocated to the Standard Firm Storage service.

PG&E proposes no changes to the cost allocation and rate design for negotiated firm or negotiated as-available storage services, and no changes for parking and lending services.

Gas storage shrinkage has been unbundled from the backbone shrinkage factor and will be applied to firm injection for Standard Firm Storage services.

The standard firm, negotiated firm, negotiated as-available, and parking and lending rates are presented in Appendix 14-1, Table 14.1-10.

(4) Load Balancing and Self-Balancing Services

Storage costs allocated to pipeline load balancing will continue to be bundled in all backbone transmission rates.

PG&E proposes to continue the self-balancing service option that was established in D.00-05-049, even though there has been little interest in this program. The self-balancing credit will still be based on 80% of the total storage balancing assets. Customers or balancing agents who elect self-balancing on a daily basis can opt out of PG&E's monthly balancing and receive a $0.011 per Dth credit, up from $0.005 per Dth today. For those who elect self-balancing, their share of the balancing storage costs and capacity are assigned to CGT's market storage services.

The self-balancing credit is presented in Appendix 14-1 of Exhibit 3 in Table 14.1-13.

3. Local Transmission Cost Allocation and Rate Design

a. Gas Accord Period

The Gas Accord established two all-volumetric local transmission rates, one for core customers and one for noncore customers. The local transmission rate is paid by all on-system end users and is non-bypassable. (73 CPUC2d at 822, 852.) Local transmission costs were allocated to core and noncore customers using the cold year coincident peak month (*i.e.*, January) marginal demand measure adopted in the 1995 BCAP, D.95-12-053. Average core and noncore local transmission rates were designed using the throughput adopted in the 1995 BCAP.

PG&E states that the cost of serving individual customers within the noncore customer class differs widely from customer to customer, and all customers within the class pay the same single average local transmission rate. Such a rate design results in significant cost subsidies being paid by certain large and/or well-situated customers (*e.g.*, close to a backbone transmission line). This averaging of the local transmission rate has caused certain customers to seek backbone level rates or other economic transportation service alternatives. If a backbone level (*i.e.*, end user backbone level service) rate structure is adopted, all other core and noncore customers who are not directly connected to backbone facilities will pay a larger share of the local transmission costs in their rates. That is, if a backbone level rate structure is adopted, the local transmission costs that are currently assigned to customers connected to the backbone will have to be reallocated to the customers remaining on the local transmission system.

b. 2004 Proposals

(1) Core and Core Wholesale

For 2004, PG&E proposes to continue the single average local transmission rate for core customers. PG&E's proposed local transmission rate for core retail is $ 0.419 per dth.[67] (Ex. 3, Table 14.1-11.) PG&E also proposes that this core retail local transmission rate apply to core wholesale customers[68] because they are provided the same level of APD reliability as PG&E's retail core customers. Wholesale customers, on behalf of their retail customers, also receive a pro rata

[67] The local transmission rate for core retail in 2003 was $ 0.287 per dth.

[68] The local transmission rate for core wholesale in 2003 was $ 0.149 per dth.

share of the core's Redwood backbone capacity at core's vintage rates, and an optional pro rata share of the Core Firm Storage allocation.

(2) Noncore

For noncore customers, instead of a single average local transmission rate,[69] PG&E proposes segmenting the noncore class into a four-tier rate design based on a customer's annual usage. PG&E views this as a first step in deaveraging the noncore local transmission rate.

Under PG&E's proposal, there would be four tiers of noncore customers. Tier 1 serves those customers with annual loads of less than 3 million therms. Tier 2 serves those customers with annual loads of 3 million therms to 49.9 million therms. Tier 3 serves those customers with annual loads of 50 to 124.9 million therms per year. Tier 4 serves those customers with annual loads of 125 million therms or more. PG&E's proposed 2004 local transmission rates are $ 0.201, 0.154, 0.150, and 0.075 per Dth for Tiers 1, 2, 3 and 4, respectively. (Ex. 3, Table 14.1-11.)

This noncore local transmission proposal is designed to discourage uneconomic bypass by substantially reducing local transmission rates for those customers who desire a backbone level rate.

Since the beginning of the Gas Accord, several noncore customers have attempted to bypass PG&E's local transmission system. Today, approximately 26 customers are directly connected to backbone facilities. If a backbone level rate structure was adopted, it is uncertain how much of the total noncore throughput would connect to the backbone to avoid local transmission rates.

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[69] The local transmission rate for noncore in 2003 was $ 0.149 per dth.

PG&E believes it could be substantial, given that Tier 3 and Tier 4 throughput totals over 700 MDth/d for only 18 customers.

If one assumes that 600 MDth/d of load connects directly to the backbone, local transmission rates for both core and noncore will increase as compared to the local transmission rates that PG&E has proposed. This is illustrated in Table 14-11 of Exhibit 3 at page 14-25. If local transmission rates increase under a backbone level rate structure, it may become economic for additional customers to build directly to the backbone to avoid paying local transmission rates.

4. Other End User Rate Components

a. Customer Access Charge

(1) Gas Accord Period

The customer access charge (CAC) recovers the costs of providing and maintaining a customer's service connection, including the service line, regulator, and meter.

The CAC revenue requirement was originally set in the GRCs as part of the distribution base revenues. The costs allocated to transmission-level customer classes were based on each classes' respective share of scaled customer marginal cost revenues adopted in the 1995 BCAP, D.95-12-053. Once these costs were allocated to transmission-level customers, and the rates set for the Gas Accord, the transmission-level costs were excluded from the distribution base revenue allocation in subsequent BCAPs. Since transmission-level CACs are now addressed in the Gas Accord structure proceedings, these charges were excluded from PG&E's 2003 GRC, A.02-11-017. D.02-08-070 extended the CAC through 2003.

Industrial transmission customers served under Schedule G-NT pay a six-tier monthly charge based on annual usage. Wholesale customers pay a customer-specific monthly charge.

At the beginning of the Gas Accord, the Schedule G-UEG served one customer, PG&E's Utility Electric Generation (UEG), who paid a fixed monthly CAC. To facilitate divestiture of the UEG facilities, an all-volumetric charge was adopted on an interim basis in the 1998 BCAP, D.98-06-055, for existing and divested UEG. Cogenerators paid an all-volumetric CAC, calculated on a 60-day lag to achieve rate parity with the UEG's rate.

(2) 2004 Proposal

For wholesale and industrial customers, PG&E proposes to continue the existing customer access rate design methodology based on an updated customer access cost of service.

For industrial customers, PG&E proposes to add two additional tiers to its existing six-tier structure. The additional tiers would be applicable to very large customers with Tier 7 serving annual loads from 60 million to 239.9 million therms and Tier 8 serving annual loads of 240 million therms and above. PG&E proposes to apply the same eight-tier industrial rate structure to the new proposed single electric generation class.

For wholesale customers, an updated CAC was developed for each wholesale customer.

PG&E's proposed CACs for industrial and wholesale customers are shown in Table 14.1-12 of Exhibit 3. Under PG&E's proposed CACs for industrial customers, the increased charge would range from $11.92 to $39,256.31. For wholesale customers, the proposed increases in customer access charges would range from $437.05 to $12,626.59.

b. Customer Class Charge

The customer class charge collects the public purpose program costs for such things as the California Alternative Rates for Energy program, energy efficiency and low income energy efficiency, and customer energy efficiency, and forecast period costs and balancing account costs established in the GRCs, BCAPs, annual true-ups, and other regulatory or legislative proceedings. The customer class charge also collects costs established under the Catastrophic Event Memorandum Account. Customer class charge rate components will continue to be updated in the BCAPs and annual true-ups. Customer class charges are paid by all on-system end users.

PG&E proposes one change to the customer class charge. PG&E proposes to eliminate the cogeneration distribution shortfall account and to recover the distribution costs allocated to distribution-level customers served from transmission-level rate schedules through a distribution rate component in the customer class charge. This is discussed in the distribution rates section.

c. Transmission-level Eligibility Criteria

Under PG&E's current tariffs, noncore customers connected to distribution-level assets are eligible for transmission-level rates if their average historical gas use through a single meter meets the following two standards: (1) is greater than 3,000,000 therms per year for the previous three years, and (2) is greater than 2,500,000 therms in the most recent 12-month period. PG&E performs annual reviews each January to determine continued eligibility for transmission rates. Administering and monitoring compliance with the above criteria has become burdensome, ambiguous and confusing to customers.

PG&E proposes to simplify the transmission-level eligibility standard by removing the two-stage standard, and replacing it with a single standard of eligibility. Under the new criteria, distribution-level noncore customers will receive transportation service under transmission-level rates during any month when their historical 12-month usage is 3 million therms or higher. Eligibility is based on a customer's average monthly usage as defined in PG&E's Gas Rule 1.

This change will simplify the eligibility standards, and ensure that eligible customers will pay transmission-level rates during the first month they qualify, rather than waiting until the next year's annual review for qualification.

According to PG&E, this proposal will not result in any cost shifts or rate impacts.

d. Distribution Rates

(1) Allocation of Distribution-level Costs

In D.98-06-073, a settlement regarding the treatment of distribution-level costs allocated to industrial transmission customers was adopted. The settlement allocated 50% of these distribution-level costs to shareholders, and the remaining 50% to other distribution-level customer classes for the remainder of the Gas Accord. D.02-08-070 extended this rate treatment through 2003.

For 2004 and thereafter, PG&E proposes to reestablish a distribution rate component in the customer class charge for the industrial transmission customer class. PG&E will recover these distribution costs directly from the industrial transmission customer class, rather than through a partial cost subsidy from all other distribution-level customer classes. This proposal will result in a slight increase in rates for industrial transmission customers and a slight decrease in rates for all remaining distribution-level customers.

Cogeneration customers situated on distribution-level facilities are also allocated a share of the distribution-level scaled marginal cost revenues from the BCAP. The Gas Accord decision removed the distribution rate component from these costs and collected the distribution costs from cogeneration and UEG end users through a cogeneration distribution shortfall rate component in the customer class charge.

For 2004, PG&E proposes to recover distribution revenues allocated to cogeneration customers from a distribution rate component in the customer class charge paid by cogeneration and electric generation customers, and eliminate the cogeneration shortfall account in the customer class charge. There is no rate impact from this proposal on any customer class.

(2) Balancing Account Protection

In the Gas Accord, balancing account protection for noncore distribution revenues was removed. As a result, noncore distribution revenues were exposed to throughput risk. Core distribution revenues continue to be protected, which creates incentives to shift costs to noncore customers and to overstate noncore throughput forecasts in the BCAPs. Due to the migration of noncore customers to core, conservation, and a slower economy, PG&E has experienced a distribution revenue shortfall at its shareholders' expense. Also, noncore distribution loads are sensitive to fluctuations in weather.

PG&E proposes 100% balancing account protection for noncore distribution revenues. PG&E notes that in D.02-12-017, SoCalGas was granted 100% balancing account protection for noncore throughput revenue risk on distribution and local transmission revenues beginning in 2003.

5. Single Electric Generation Class

a. Gas Accord Period

When the Gas Accord began, PG&E's rate schedules serving generators were Schedule G-UEG and Schedule G-COG. Schedule G-UEG served only one customer, PG&E's UEG, which at the time operated seven gas-fired electric generation plants. Schedule G-COG served distribution and transmission-level cogeneration facilities and solar electric generation projects. In accordance with the rate parity provisions of §454.4, PG&E limits the volume of gas qualifying for G-COG to the lesser of: (1) the cogeneration gas allowance (CGA) for each kilowatt-hour of net electricity generation fueled by natural gas; or (2) the quantity of gas actually consumed in the cogeneration facility. Cogeneration volumes in excess of the CGA pay the customer's otherwise applicable rate.

The parity rule was applied during the Gas Accord in the following manner. Backbone transmission rate parity with UEG transportation contracts was provided to cogenerators for services from PG&E's transmission department on a path-specific and service-specific basis. (73 CPUC2d at 824.) End user parity was achieved by averaging the costs allocated to UEG and cogeneration customer classes so that each class paid the same per unit rate. The distribution costs allocated to distribution-level cogenerators were collected from all cogeneration and UEG end users. (73 CPUC2d at 826.)

During the Gas Accord period, Schedule G-UEG was renamed G-EG and was revised to serve transmission-level gas-fired generators including merchant power plants, independent power production facilities, municipalities, irrigation districts and joint power authorities, divested UEG, and PG&E's two remaining nondivested UEG plants.

In Resolution G-3242, and D.00-04-060, SoCalGas received approval for a single electric generation customer class serving all gas-fired generators, cogenerators, independent merchant plants and former utility electric generation plants. The class was further segmented by size (customers with usage of 3 million therms per year or less pay an additional distribution-level component) and the collateral discount rule (CDR)[70] and CGA were eliminated. The Commission stated in D.00-04-060 that the segmented rate proposal complied with § 454.4 because it treats all electric generators alike, regardless of their size, location, or present or former ownership. (D.00-04-060 at pp. 53-54.)

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[70] The CDR has historically required cogeneration customers to receive any rate discount granted to a UEG customer.

b. 2004 Proposal

To align PG&E's electric generation rate design structure with changes resulting from electric industry restructuring and with SoCalGas and SDG&E's electric generation rate structure, PG&E proposes a single electric generation class serving utility electric generation, cogeneration, divested electric generation, municipalities, solar powered plants and merchant power plants. PG&E proposes to segment the class by transmission and distribution service levels, with customers using 3 million therms or greater served from the transmission-level rate, regardless of their service facilities. PG&E contends that segmented electric generation rates provide a more accurate price signal for new potential generator projects that are considering locating in PG&E's service territory, and would provide a consistent statewide rate design structure.

Under PG&E's proposal for 2004, distribution-level electric generation customers will pay a distribution rate component based on 25% of the distribution costs allocated to distribution-level electric generation and cogeneration customers. The remaining 75% of the distribution costs allocated to these customers will continue to be spread equally to all transmission and distribution-level electric generation customer volumes through the distribution rate component.

The electric generation class will be limited to customers with loads greater than 250,000 therms annually. Existing cogeneration and solar electric generation customers qualifying for service under Schedule G-COG, who use less than 250,000 therms annually, or are served under a core rate schedule for their use in excess of the CGA, as of December 31, 2002, will be grandfathered to

Schedule G-EG for their loads serving generation.[71] These cogeneration customers will be required to provide the same electric output information that is currently used to calculate their CGA. However, their loads qualifying for rates under Schedule G-EG will be based on the heat rates specified in Table 14-12 – Generator Heat Rates of Exhibit 3. All customers taking service from Schedule G-EG must purchase their gas from a third party supplier. Cogeneration customers who are served under the grandfathered provision above, will be given a one-time option to discontinue service under Schedule G-EG and convert to a core service for all of their use. Such customers will be restricted from the electric generation class from that point forward.

The distinction as a transmission or distribution electric generation customer is also consistent with PG&E's proposal to change the transmission-level eligibility criteria that has been mentioned earlier in this section of the decision.

PG&E proposes to eliminate the CGA in conjunction with measures to ensure that the volumes qualifying for the electric generation rate are limited to those used to generate electricity. PG&E recommends that all customers who qualify for the electric generation rate have a separate PG&E meter installed to measure gas use of the electric generation facilities, and that those facilities be monitored on a regular basis. Where separate metering is not economically feasible on existing generation facilities, gas volumes serving electric generators

[71] In PG&E's comments to the proposed decision, PG&E recommends that the cut-off date of December 31, 2002 be changed to December 31, 2003. PG&E states that such a change will allow all cogeneration facilities currently served under Schedule G-COG to have the same service options on a going-forward basis.

will be specifically measured using other gas metering devices and by the recorded net electric generation's output in kilowatt hours multiplied by the average heat rate for similarly sized electric generation facilities as shown in Table 14-12 of Exhibit 3. PG&E plans to update or modify the generator heat rates in Table 14-12 to reflect new technologies as they become available.

PG&E proposes to eliminate the CDR regarding cogenerator rate parity with UEG on backbone rates, end-user rates and rate discounts, and to eliminate the options for cogenerators to receive advance notice of UEG service elections. With a single electric generation class serving all electric generation customers, rate parity between certain UEG customers and cogenerator customers would be impossible to implement. Backbone transmission services will be offered on a path-specific and service-specific basis to all customers.

PG&E proposes to eliminate the distinctions in cost allocations and cost exemptions for the single electric generation class customers and require all customers to pay their pro rata equal-cents-per-therm share of franchise fees and Commission fees.[72] Currently, UEGs are exempt from franchise fee surcharges under §§ 6350-6354, and are exempt from Commission fees. Under rate parity, the code sections extended the franchise fee exemption to cogenerators, PG&E's divested UEGs, municipalities, and merchant power plants pay franchise fees and Commission fees in their monthly bills. With a single electric generation class serving all gas-fired electric generation, the franchise fee provisions become difficult to apply, and the intent of parity under § 454.4 becomes less meaningful.

[72] Once this proposal is adopted, PG&E will update the customer class charges to reflect the allocation of Commission fees and franchise fees to all G-EG customer volumes in the first BCAP or true-up rate change.

The elimination of the cost exemptions for cogenerators and UEG would simplify cost allocation and rate design, and provide a level playing field for this customer class.

The proposed rates for the electric generation class which apply to Schedule G-EG are shown in Appendix 14-1 of Exhibit 3 in Table 14.1-2.

6. Other Proposals

Other parties have proposed certain cost allocation and rate design changes. These proposals include the following: a backbone level rate structure; 100% roll-in of Line 401 costs to the core; and increase the system load factor that PG&E uses, or use path-specific load factors.

B. Backbone Transmission Cost Allocation and Rate Design

1. Roll-In Of Noncore Redwood Path Costs

a. Position of the Parties

(1) CCC/Calpine

CCC / Calpine support PG&E's proposal to roll-in the costs of Lines 400 and 401. However, they contend that current circumstances require that PG&E eliminate completely the core's preferential access to cheap, vintage Line 400 capacity, and that a single Redwood rate applicable to both core and noncore customers be adopted.

CCC / Calpine state that this roll-in issue should be decided now, rather than deferred to a future proceeding. Parties had the opportunity to litigate this issue during this proceeding, and parties presented evidence regarding Line 401.

CCC / Calpine assert that the energy crisis demonstrated that both core and noncore customers need, use and benefit from Line 401. According to the CCC / Calpine witness, the PG&E system was less constrained during the energy crisis than the SoCalGas system due to Line 401. Line 401 kept prices at Topock for delivery into the PG&E system significantly lower than Topock gas into the

SoCalGas system. Even TURN conceded during cross-examination that the availability of Line 401 capacity during the energy crisis benefited customers by reducing prices at Topock. Line 401 also produces $4 million per year in compressor fuel savings for PG&E's core customers. Without Line 401, PG&E would have had to severely curtail noncore loads on its system, including electric generation customers.

CCC/Calpine point out that in D.97-08-055, the Commission stated that it would revisit the incremental rate treatment for Line 401 if it can be shown that Line 401 provides substantial customer benefits. CCC/Calpine assert that the benefits incurred by core gas customers as a result of the availability of Line 401 meets the Commission's substantial customer benefits standard. PG&E's witness also agreed that the standard for attributing the costs of Line 401 to core customers has been satisfied. (2 RT 130.)

PG&E admits that the core has benefited from Line 401, which justifies the roll-in of Line 401 costs. But to avoid too much of an upset to customers, only a roll-in of 20% is sought. CCC/Calpine contend that the Commission should take PG&E's proposal to its logical and appropriate end, and allow a full roll-in, or averaging, of Line 400 and 401 costs.

TURN's argument against a roll-in of Line 401 is that it "violates the Commission's policy regarding overbuilding beyond the system's needs and economic efficiency." (TURN, Opening Brief, p. 22.) CCC/Calpine assert that this argument is speculative, and is not based on any evidence in the record. CCC/Calpine contend that the issue of whether to roll-in the costs of Line 401 is not a matter of broad policy. Rather, it is a matter of whether benefits have been demonstrated, which CCC/Calpine contend have been shown. Those benefits should be reflected in core rates.

TURN contends that core customers should not have to subsidize Line 401 on the theory that electric customers receive reliable electricity as a result of gas transported over this line. CCC/Calpine are not asking electricity customers to pay twice for the same benefits, rather they are seeking to have core customers pay for the full benefit they receive from the use of Line 401. They contend that cost savings on the gas side results in lower rates for electric generation because production costs decrease. Any cost savings that noncore customers will enjoy as a result of core customers paying for 100% of their use of Line 401 will be passed onto electricity customers in the form of lower rates.

TURN also argues that the benefits to the core of Line 401 are, at best, indirect, and dwarfed by the benefits enjoyed by noncore customers. CCC/Calpine contend that TURN's witness admitted that the availability of Line 401 capacity during the energy crisis benefited customers by reducing prices at Topock. (7 RT at 707.) TURN also states that core customers purchase significant amounts of gas at the border. Thus, according to TURN's own argument, core customers should be paying something for this benefit.

(2) CAPP

CAPP proposes that the costs of Line 400 and Line 401 be fully rolled-in. CAPP contends that the statement in D.97-08-055 that before any roll-in of costs can occur, there must be substantial benefits to core customers, has been satisfied. The benefits of Line 401 include: sufficient gas in northern California during periods of unanticipated demand; the amelioration of the price effects of a shortfall of capacity at a time of historic high prices; the creation of a viable spot market for citygate purchases, which has contributed to the flexibility of PG&E's core procurement activities; and reduction in PG&E's compressor fuel use by 6.1 MMcf/d, a benefit of $10.2 million per year using a gas price of

$4.50 per Dth. CAPP contends that none of these benefits were present prior to the Gas Accord. Without Line 401, Northern California would have experienced drastically higher prices.

CAPP submits that the only issue with respect to the treatment of the Line 401 costs is whether the roll-in should be restricted to 20% as PG&E proposes. CAPP contends that PG&E has not provided any justification for restricting the roll-in of costs to 20%. CAPP contends that the 20% figure appears to be an after-the-fact effort to create a rationale for this element of PG&E's proposal. CAPP asserts that limiting the roll-in to 20% is purely arbitrary and nonsensical given that core customers have received substantial benefits from this capacity.

With respect to ORA's argument against the roll-in of Line 401 costs, CAPP asserts that the record in this proceeding now includes extensive evidence of the actual operations of Line 401, and the substantial customer benefits that these facilities have had on the overall market and on core customers in Northern California.

In response to TURN's argument that the roll-in of Line 401 costs is contrary to Commission precedent, CAPP asserts that the decision made it conditional on the outcome of future evidentiary developments. The Commission identified "substantial benefits" as a reason for whether a roll-in of Line 401 costs would be appropriate. The record demonstrates that the benefits from Line 401 have been substantial.

CAPP asserts that TURN's argument that if Line 401 had not been built, that another company would have built a different pipeline, is speculative. Such speculation is of little value because it is unclear how much other capacity would have been built, or when. Instead the evidence shows the Line 401 benefited customers when there was an unanticipated surge in demand for gas in 2000-2001.

TURN cited a Commission report which concluded that the dramatic border price increases were not caused by inadequate natural gas infrastructure. CAPP points out, however, that the same report reinforces the point that the presence of Line 401 led to a lower Topock-into-PG&E price compared to the Topock-into-SoCalGas price, and that the Baja path was running at less than full capacity because PG&E had Line 401 available.

CAPP also refutes TURN's argument that even if Line 401 did put downward pressure on border gas prices, that the benefits primarily accrued to noncore customers. CAPP points out that such an argument is incorrect. PG&E's witness testified that PG&E's Core Procurement Department purchased about 745 MDth/d on average during the relevant time period, while PG&E holds about 600 MDth/d of interstate capacity coming out of Canada. A comparison of these two figures proves that PG&E's Core Procurement Department enjoys a direct benefit from a lower Topock price, as it cannot meet all of its demand from Canada-sourced supplies. As PG&E witness Gee said, "401 has brought additional supply into the marketplace in which all market participants, including core, has benefited from."

(3) NCGC

PG&E proposes a 20% roll-in of Line 401 costs to the core.

CCC/Calpine advocate that instead of a 20% roll-in of Line 401 costs, PG&E should completely eliminate the core's preferential access to cheap, vintaged Line 400 capacity, and should establish a single Redwood rate applicable to both core and noncore customers. The reasoning for the elimination of the vintaged path is that all customers, including the core, benefit from the availability of Line 401 capacity.

TURN recommends that the Commission retain vintaged Line 400 rates for core customers, and that no roll-in of Line 401 costs occur.

NCGC supports the full roll-in of Line 401 costs with Line 400 costs. TURN's position should be rejected. PG&E and CCC/Calpine have established that Line 401 benefits all customers.

NCGC points out that PG&E's core customers are paying a full rolled-in rate for transportation service on the PGT-Northwest system from Canada to the California-Oregon border. NCGC contends that if a full roll-in is appropriate for the Oregon and Washington segments of the Expansion Project, it is certainly appropriate for the California portion.

If the Commission decides to adopt PG&E's partial roll-in proposal, NCGC urges the Commission to direct that the phased roll-in be effected in increments of 20% over five years so that a full roll-in will be accomplished by the end of 2008. NCGC contends that the annual rate impact on the core each year would be negligible. An annual 20% roll-in of Line 401 and Line 400 will result in only a 0.8% increase in bundled core customer rates each year. An average residential customer using 50 therms per month would see a rate increase of only 30 cents per month (0.76%) for each year of the five-year phased roll-in period. Given the benefits that Line 401 has provided to core customers, NCGC contends that this small rate adjustment is justified.

NCGC asserts that by removing transportation rate differences that give a preference to one basin or supply point over another will promote gas-on-gas competition. NCGC believes it would be appropriate for the Commission to consider CAPP's recommendation for a full roll-in of all backbone facility costs and the development of a single postage stamp rate utilizing a single system-wide load factor.

(4) ORA

ORA is opposed to PG&E's proposal to roll-in the costs of Line 401 to the core.

ORA contends that when PG&E was granted the CPCN to build Line 401, it was premised on the assurance that existing customers would not have to pay for the costs of Line 401.

In the Gas Accord decision, the Commission approved a partial roll-in of Line 401 to the noncore, but only because the noncore had agreed to it as part of the Gas Accord Settlement Agreement. The Commission also pointed out in D.97-08-055 that it would strongly disfavor any future PG&E request for a full roll-in of Line 401 costs if such a roll-in would increase either core or noncore rates. PG&E's proposed roll-in will result in substantial rate increases which affect both retail and wholesale core customers.

(5) TURN

PG&E proposes to partially roll-in the costs of Line 401 into the core's vintaged rates. TURN opposes the roll-in of any Line 401 costs into core rates.

TURN contends that such proposals breach PG&E's past commitments regarding Line 401. TURN contends that nothing in the Gas Accord has relieved PG&E from its prior commitments with respect to assuming the risks of cost recovery of Line 401 and the protection of captive customers from those costs and risks.

PG&E applied for a CPCN to build Line 401 in A.89-04-033. The Commission granted the CPCN in D.90-12-119, stating that "No costs of the expansion will be allocated to PG&E's existing customers, except to the extent that PG&E itself is a customer of the Expansion Project." (D.90-12-119 at 37-38)

TURN points out that when the Commission approved the Gas Accord Settlement Agreement in D.97-08-055, the Commission noted that PG&E's application for a CPCN to build Line 401 "promised to insulate original system ratepayers from any risks and costs of Line 401." (73 CPUC2d at 772) The Gas Accord decision also stated that PG&E "took advantage of the Commission's 'let the market decide' policy for new pipeline capacity, in exchange for assuming responsibility for associated costs and risks. [The Commission is] obligated to defend those customer protections vigorously. (73 CPUC2d at 773.)

TURN contends that the Commission recognized in the Gas Accord decision that the roll-in of Line 401 costs to the noncore was economically inefficient and violated principles of incremental ratemaking. However, the Commission approved the roll-in for noncore customers, and stated:

> "only because noncore representatives have agreed to it…. Therefore, our finding that the Gas Accord is in the public interest is predicated on the fact that the core retail and core wholesale end users will continue to benefit from low, vintaged rates on Line 400 and will not have to pay for Line 401 costs. We would strongly disfavor any future PG&E request for a full roll-in of Line 401 costs if such roll-in would increase either core or noncore rates (absent an all-party settlement), whether such request occurred before or at the expiration of the Gas Accord." (73 CPUC2d at 782.)

The Commission warned that the approval of the Gas Accord would not stand as precedent in favor of rolled-in rates and approved the Gas Accord based on the fact that PG&E would not roll-in Line 401 rates to the core. (73 CPUC2d at 775.)

PG&E attempts to justify the Line 401 roll-in by describing the benefits that the core has received as a result of Line 401. TURN points out that when the Gas Accord was approved, it acknowledged that the core may receive small benefits from Line 401. (73 CPUC2d at 774.) TURN argues that these claimed benefits are at best indirect, and subject to dispute as to their magnitude. Also, any benefits to the core are dwarfed by those enjoyed by noncore customers.

To allow PG&E's partial roll-in of Line 401 would also violate the Commission's policy regarding overbuilding beyond the system's needs and economic efficiency. As TURN argued in the Gas Accord:

> "allowing rolled-in ratemaking could undermine future market tests for new capacity in the gas pipeline industry and perhaps in other industries. To weaken 'let the market decide' policies after construction of utility expansions could harm the Commission's credibility. If PG&E is now allowed to roll the cost of unnecessary assets into original system rates, then future market players might be tempted to deter competition by overbuilding new capacity, hoping the Commission will later shift the risks of undersubscription or underutilization back to captive customers. Utilities and their competitors would question the Commission's resolve in enforcing the assignment of risks and costs to the sponsors of new capacity." (73 CPUC2d at 773)

TURN points out that no advocate of the Line 401 roll-in addressed these issues of anticompetitiveness and preventing inefficient overbuilding.

Granting PG&E's proposal to roll-in 20% of the Line 401 costs will also erode the Commission's credibility and send a message that the Commission does not stand by its decisions, nor does it hold parties accountable for their sworn statements. (*See* 73 CPUC2d at 779.) TURN contends that the Commission should not deprive core customers of the promises made to them when authorization was sought to construct Line 401.

TURN asserts that the arguments of CCC / Calpine rely on a faulty historical premise. If PG&E has not constructed Line 401, TURN contends that it is likely that another pipeline company would have built a competing pipeline to supply Northern California. (*See* 39 CPUC2d 69, 118; Ex. 4, p. 3-11.) One cannot rewrite history by simply assuming that the benefits of additional capacity would not have existed absent the building of Line 401.

The CCC / Calpine witness spent considerable time discussing the fact that without Line 401's capacity, there would have been electric blackouts in Northern California due to curtailments. Since residential electric customers are often PG&E core gas customers, they directly benefit from Line 401. TURN contends that this argument assumes that residential ratepayers should have to pay twice for the same benefit, just because they take gas and electric service. TURN asserts that there is no policy rationale for charging core gas ratepayers for providing reliable gas service to electric generators. PG&E's electric ratepayers will have paid for whatever benefits they received from Line 401 in their electric rates. There is no justification for charging them again as gas ratepayers for those same benefits.

TURN also contends that there is no direct causal link between having the core pay for 20% or 100% of Line 401 capacity and reliable electric service. Line 401 capacity reduces the chances of gas diversion curtailment for <u>all noncore customers</u>. There is no reason why core customers should have to pay to reduce the potential of diversions for industrial noncore customers. In the event of a diversion, core customers would have to pay a significant penalty if noncore gas is diverted.

TURN also contends that the CCC / Calpine witness' conclusion that Line 401 reduced the gas prices at the Southern California border are speculative.

First of all, this argument ignores that if Line 401 had not been built, an alternative pipeline would have been built. Second, there is little factual foundation for the argument that the difference between PG&E-Topock and SoCalGas-Topock prices was caused by greater constraints on the SoCalGas system. The Commission staff's "California Natural Gas Infrastructure Outlook, 2002-2006" report concluded that the dramatic border price increases were not caused by inadequate natural gas infrastructure, but by market manipulation and insufficient storage injection by noncore customers. (Report, pp. 25-30.)

TURN asserts that there is substantial information in the record that conclusively indicates that other factors were more direct causes of the price differentials. TURN points out that no party analyzed the impact of upstream market manipulation on the El Paso system on the PG&E-Topock and SoCalGas-Topock prices. The Commission has maintained in D.02-07-037 at pp. 6 and 7 that the deliberate withholding of capacity and market manipulation by El Paso and its marketing affiliate contributed significantly to gas price increases. (D.02-07-037 at 6-7.) The parties also did not analyze the effect of fraudulent price reporting or market manipulation, or the temporary lifting of the price cap on the secondary market under FERC Order 637 on gas prices. TURN asserts that one cannot conclude that the simple presence of slack capacity on the PG&E was responsible for the large disparity in prices between PG&E-Topock and SoCalGas-Topock.

Even if one assumes that the capacity on Line 401 placed downward pressure on border prices is true, TURN asserts that any resulting benefit flowed to those customers who either purchase gas at the border or citygate, or who purchase gas at prices indexed to border prices. TURN points out that it is primarily noncore customers who buy their gas supplies at the border or citygate. PG&E's core customers use interstate capacity in order to purchase gas at the producing basins. The core would purchase, at maximum, about 40% of its gas at the border during the three peak winter months. On an annualized basis, that is less than 20% of the core's gas needs.

TURN contends that PG&E's noncore customers (or their marketers) would have been the primary beneficiaries of the price difference between PG&E-Topock and SoCalGas-Topock. The fact that core customers also obtained some benefit does not lead to the conclusion that the core should pay for the costs of Line 401.

TURN contends that another major flaw with the CCC / Calpine's analysis is that the PG&E and SoCalGas systems are inherently different in design. The SoCalGas system is "storage-rich," so a greater amount of peak demand is met through storage withdrawals rather than flowing supplies. During the energy crisis period, SoCalGas' storage system went into winter with record low levels of gas in storage, primarily due to almost no injections into storage by noncore customers during the summer of 2000. In contrast, the PG&E system relies to a greater extent on flowing supplies to meet peak demand.

TURN contends that PG&E has not explained how the citygate market has benefited the core, and there is little basis for concluding that the core received any major benefit from the citygate market. Even if it did exist, the core purchased only 17 Bcf at the citygate in 2002, out of a normal annual demand in 2004 of 292 Bcf (only about 6% of demand) which is hardly a significant amount.

TURN also argues that a roll-in of Line 401 costs may not benefit PG&E's noncore customers. TURN asserts that most of the holders of interstate capacity on the PG&E system are marketers, not PG&E's noncore customers. A noncore customer who buys gas at the citygate from a marketer will pay a market price, not a cost-based rate. TURN asserts that a reduction in the cost of one of several potential transportation paths may not translate into a lower market price at the citygate at all, but rather it may result in increased profits for the marketer who delivers over that path. Such a result is not in the best interests of California consumers.

TURN contends that if core customers require service over Line 401, that they will pay the associated costs. If Canadian gas is more economic than Southwest gas, the core could utilize Line 401 interruptible capacity and pay the applicable tariff rate. If core does not use Line 401, it should not pay. That was the original bargain behind Line 401.

TURN also notes that those in favor of the Line 401 roll-in rely on the phrase that "only a showing of substantial customer benefit can overcome the allocation of Line 401 costs." (73 CPUC2d 773.) TURN contends this phrase was taken out of context, and that the entire passage must be considered.

Another justification that the proponents use is that a 20% roll-in of Line 401 costs to the core will only increase core bundled rates by only .8%. (Ex. 4, p. 14-19, fn. 7.) However, when you add the increase of $0.006 per therm by the forecasted core throughput of 294,537 MDth for 2004, that increase amounts to $17.67 million. TURN points out that since others are pushing for a full roll-in, the 20% roll-in would just be the beginning. The approval of any of the roll-in proposals would increase the magnitude of financial hardship on core customers. This burden would be further magnified if PG&E's proposal to increase the local transmission cost allocation to the core is increased by 40.5%. (*See* Ex. 76.)

TURN contends that its position has been clear and consistent over the roll-in of Line 401 costs. TURN supports full regulation of bundled utility service whenever possible. But once certain large customers are allowed to strike their own deals, the financial bargains struck at that time must be maintained so that the residential and small commercial customers are not left holding the bag.

(6) PG&E

PG&E proposes a Redwood path rate design for core and noncore customers that reflects a partial roll-in of all Redwood path capacity and costs, except for contracts under Schedule G-XF. Core Redwood path rates would include a 20% roll-in of Line 401 costs for 2004. This 20% roll-in would moderate the impact on core customers, while moving toward a reduction of the large disparity between the rates paid by core and noncore customers for the same Redwood path service. Schedule G-XF contracts would continue to be priced based on the incremental Line 401 Pipeline Expansion Project cost of service as required by D.94-02-042.

PG&E points out that parties that benefit from the vintaged Line 400 rates oppose PG&E's proposal. The parties who represent noncore customers do not believe that the 20% roll-in goes far enough to reduce the core/noncore rate disparity because they believe the core benefits from Line 401. PG&E contends that its 20%proposal is a balanced approach.

PG&E asserts that the core receives a "substantial customer benefit" from Line 401. During the 2000 to 2001 period, the capacity on Line 401 alleviated high gas and electric prices in Northern California. Without Line 401, PG&E asserts that PG&E's system would have become constrained and customers would have faced much higher prices. Also, Line 401 and the Redwood path provided access to lower-priced Canadian gas. As a result of the price advantages for Canadian gas, the Redwood path, including Line 401, was highly utilized throughout the Gas Accord period. Table 3-2 of Exhibit 4 shows that utilization of the Redwood path averaged over 90% from mid-1998 to mid-2002.

PG&E points out that the citygate market has become much more liquid since the beginning of the Gas Accord. Line 401 brings additional supply to the market, which benefits all participants, including core customers. Without the capacity provided by Line 401, PG&E contends that the same citygate purchases would not be available.

PG&E contends that contrary to TURN's argument, the Commission did not grant core a "vested right" to vintage-priced Line 400 capacity. PG&E says that Commission policy has been, and continues to be, that those who benefit should pay their share of costs. PG&E asserts that Line 401 has been used at high load factors, which clearly demonstrates its value to the California market. In addition, new pipeline capacity continues to be built which indicates a demand for interstate pipeline capacity even beyond that provided by the PG&E expansion project.

Responding to TURN's argument that another interstate pipeline equivalent to Line 401 would have been built if Line 401 was not, is unsupported and contradicted by the evidence. PG&E showed that had Line 401 not been built, it is unlikely that as much alternate capacity would have been built. As recently as 1998 and 1999, there was substantial slack capacity in the system.

PG&E also states that Line 401 capacity has helped moderate costs for PG&E's customers, both gas and electric, and has reduced Northern California's exposure to problems on the El Paso system and at the California border. PG&E also states the record contains evidence that Line 401 has ensured that there are sufficient gas supplies to Northern California during time periods of unanticipated demand. Line 401 has also ameliorated the price effects of a shortfall of capacity at a time of historic high prices. Line 401 has also brought about the creation of a viable spot market for citygate purchases, and thus contributed greatly to the flexibility of PG&E in its core procurement activities. None of these benefits were present at the time the Gas Accord was initially approved by the Commission.

In an attempt to downplay the benefits resulting from the capacity provided by Line 401, TURN ignores the effect of the connection between intrastate load factors and gas prices. PG&E explained the relationship between pipeline utilization and constraints, and price differentials. The fact that prices rise when pipelines are constrained is a fact that is well established. PG&E also demonstrated that the PG&E system was generally unconstrained and did not contribute appreciably to price increases beyond border prices (at Malin and PG&E Topock). PG&E also explained that the SoCal-Topock price, and the price differential between PG&E-Topock and SoCal-Topock, reflect constraints on the intrastate SoCalGas system. Both PG&E and CCC/Calpine presented evidence that the SoCalGas system was highly constrained in 2000-2001. Without Line 401, PG&E says that one can only imagine how much higher prices in Northern California would have been.

PG&E asserts that PG&E and CCC/Calpine have shown that Line 401 has benefited core customers, but core is not paying for any of these costs.

PG&E also argues that in D.97-08-055, the Commission departed from the methodology set in D.94-12-058 by adopting partially rolled-in rates and the use of a system wide load factor for Line 401.

b. Discussion

PG&E proposes a 20% roll-in of Line 401 costs, while CCC/Calpine and others favor a full roll-in of Line 401 costs.

PG&E's 20% roll-in would result in 2004 Redwood path rates of $0.176 per Dth for the core and $0.329 per Dth for the noncore. In comparison, the 2003 Redwood Path rates for the core and noncore are $0.125 and $0.269, respectively. TURN estimates that a 20% roll-in of Line 401 will cost core ratepayers $17.67 million in 2004. PG&E's witness acknowledged that the proposal for a 20% roll-in is just the beginning of a movement toward a full roll-in of Line 401 costs to the core. (9 RT 913-914.)

TURN contends that the Commission's prior decisions regarding Line 401 placed the cost of the project on PG&E. PG&E and the others who favor a roll-in, contend that they have demonstrated that the core has received "substantial customer benefits" from Line 401. The term "substantial customer benefits" or substantial benefits originated in the Gas Accord decision, D.97-08-055 (73 CPUC2d at 773.) Thus, our analysis of whether PG&E should be permitted to roll-in some or all of the costs of Line 401 begins with the Gas Accord decision.

As part of the Gas Accord Settlement Agreement, noncore customers agreed to a partial roll-in of Line 401 costs. Throughout the decision, the Commission mentioned the roll-in of these costs. PG&E and the proponents of the roll-in contend that the sentence referring to substantial customer benefits opened the door in this proceeding to the roll-in of Line 401 costs to the core. The sentence which the proponents of the roll-in rely on come from the following paragraph in section 5.3 of the decision, which is entitled "Features Opposing Approval" of the Gas Accord Settlement Agreement. (73 CPUC2d at 769, 771.) That paragraph reads:

> "Second, rolled-in rate treatment for Line 401 would be inefficient and contrary to incremental ratemaking principles. Loss of economic inefficiency is built into the averaging process because shippers would not face the costs of

> individual pipeline assets. In A.89-04-033, PG&E promised to insulate original system ratepayers from any risks and costs of Line 401. The Commission confirmed that none of the costs of Line 401 would be allocated to original system ratepayers. When PG&E determined the scale and timing of the expansion project, it took advantage of the Commission's 'let the market decide' policy for new pipeline capacity, in exchange for assuming responsibility for associated costs and risks. We are obligated to defend those customer protections vigorously. Only a showing of substantial customer benefits can overcome the allocation of Line 401 costs to customers that do not need or desire Line 401 capacity.

We agree with TURN that one must read the reference to substantial customer benefits in context. In section 5.3 of the Gas Accord decision, the Commission was addressing the features of the Gas Accord settlement, which did not favor approval. Section 5.2 of the decision addressed the features of the settlement in favor of its approval. Thus, the substantial customer benefits reference was to the noncore's willingness in the Gas Accord settlement to a partial roll-in of Line 401 costs. This is made clear in several passages in section 5.4, the "Conclusion" of the Gas Accord discussion.

In section 5.4, the Commission stated, "Increased costs associated with partial roll-in of Line 400 and Line 401 costs will be borne by noncore customers that freely entered into the settlement." (73 CPUC2d 774.) Two paragraphs later, the decision states in part:

> "We are also concerned that the Gas Accord has not provided enough unbundling and that parties may attempt to improperly cite our approval of the Gas Accord as a precedent in favor of rolled-in rates (when our policies continue to be in favor of incremental rates) or that parties will claim that the Gas Accord resolved numerous issue which were never specifically addressed by the Gas Accord. Rather than reject the Gas Accord in light of these concerns, we believe that the

> much better course is to approve the Gas Accord in light of its improvement over PG&E's present rates, to narrowly interpret the Gas Accord and our order approving the Gas Accord so that it will not limit our ability to further address PG&E's conflicts of interest and unbundling issues, to clarify our policies and various ambiguities in the Gas Accord so that parties will not misinterpret this decision…." (73 CPUC2d 774.)

Toward the end of section 5.4, the decision states: "In our discussion below, we also make it crystal clear that our approval of the Gas Accord cannot be cited as a precedent in favor of rolled-in rates…." (73 CPUC2d 775.)

All of the passages in section 5.4 of D.97-08-055 make clear that the Commission's policy is in favor of incremental rates, and that the approval of the Gas Accord Settlement Agreement "cannot be cited as a precedent in favor of rolled-in rates."

Then in section 6.3.1 of the Gas Accord decision, in a section entitled "Rolled-In Rates," the Commission stated:

> "Although we are approving the Gas Accord, we remain concerned that the partially rolled-in rates for Line 400 and Line 401 are contrary to our incremental ratemaking principles. PG&E was authorized to build Line 401 based upon its pledge to utilize incremental rates, and PG&E assured us at that time that PG&E's existing customers would not have to pay for Line 401 costs. Approval of partially rolled-in rates for noncore customers is reasonable here, but *only* because noncore representatives have agreed to it in the Gas Accord, presumably in return for other benefits. Full roll-in of Line 401 costs would increase core rates and would significantly conflict with our policies. However, the Gas Accord does not provide for fully rolled-in rates; it protects core retail and core wholesale ratepayers from the unjustifiable increase in rates, which would result from the rolled-in rates. Therefore, our finding that the Gas Accord is in the public interest is predicated on the fact that the core

> retail and core wholesale customers will continue to benefit from low, vintaged rates on Line 400 and will not have to pay for Line 401 costs. We would strongly disfavor any future PG&E request for full roll-in of Line 401 costs if such roll-in would increase either core or noncore rates (absent an all-party settlement), whether such a request occurred before or at the expiration of the Gas Accord." (73 CPUC2d at 782, original italics.)

Thus, the Gas Accord Settlement Agreement was adopted with the express understanding that "core retail and core wholesale customers will continue to benefit from low, vintaged rates on Line 400 and will not have to pay for Line 401 costs."

The incremental ratemaking treatment of Line 401 first began when PG&E received a CPCN for the project in D.90-12-119 (39 CPUC2d 69).[73] In the section addressing risk allocation for the project, the Commission stated:

> "Until further Commission action, we find that the project sponsors are PG&E's shareholders, and it is PG&E's shareholders and Expansion shippers, not the existing ratepayers, that bear the risk of the Expansion Project's failure to recover its revenue requirement. The shift of risk to existing ratepayers may occur, if at all, only if the Commission finds that the Expansion Project's contribution to margin would constitute a financial benefit sufficient to overcome the Project's potential burden of revenue underrecovery. However, we conclusively find that none of the costs of the Expansion Project may be recovered in any non-Expansion Project rate proceeding, advice letter or accounting mechanism." (39 CPUC2d at 81.)

[73] The incremental ratemaking treatment adopted in D.90-12-119 was affirmed in D.92-10-056. (46 CPUC2d 199, 204-205.)

Further in the CPCN decision, in which the Commission discussed the economic justification for the project, the Commission stated:

> "We note that PG&E has affirmatively stated that it will not seek to recover any Expansion Project costs (other than transportation costs) from its existing ratepayers. Such assurance is also implied from the applicant's intent to collect Expansion costs from only the project sponsors and Expansion shippers. We confirm as a condition of issuance of this CPCN that PG&E's existing ratepayers should not bear any of the cost of the Expansion. This segregation of costs, risk, and benefit is appropriate at this time, particularly since PG&E has not yet executed Firm Transportation Agreements with the Expansion shippers. … We will revisit this issue in the Expansion Project's first general rate case, when concrete evidence of shipper participation, the Expansion's costs and rates, and the potential contribution to margin will be available. (39 CPUC2d at 120.)

In Finding of Fact 103, Conclusions of Law 7 and 31, and Ordering Paragraphs 3 and 14.h. of D.90-12-119, the risk of recovery was placed on PG&E's shareholders and the expansion shippers, pending an allocation of the risk of revenue recovery as between ratepayers and shareholders, which was to be determined in a general rate case application for Line 401.

In D.94-02-042 (53 CPUC2d 215), the decision that addressed the rates for Line 401, the Commission assigned "all risks of undersubcription, and most of the risks of underutilization" of Line 401 to PG&E's shareholders. The remaining risks of underutilization were placed on the expansion shippers. (53 CPUC2d at

230.) D.94-02-042 also found that the risk of recovery of Line 401's project costs should be borne by PG&E's shareholders. (53 CPUC2d at 230, 249.)[74]

PG&E and CCC / Calpine contend that the core has realized substantial benefits from Line 401, and therefore a roll-in of the costs of Line 401 should be permitted. However, the starting point in deciding whether a roll-in proposal should be adopted is that such proposals are disfavored unless there is an all-party settlement. (73 CPUCd 782.) The benefits that a particular customer class may have received are only one factor to consider. As noted in the Gas Accord decision, the impact of a roll-in on core or noncore rates is the major concern.

Although PG&E's proposal is to only roll-in 20% of the costs of Line 401 in 2004, such a roll-in would increase both core and noncore rates as shown in Tables 14.1-3 and 14.1-4 of Exhibit 3. The effect on the core alone in 2004 amounts to approximately $17.7 million. PG&E's proposal, if approved, is only the tip of the iceberg, in that it will seek to roll-in even more of the Line 401 costs in future years. Some of the other parties already advocate a full roll-in for 2004. If such proposals are adopted, the cumulative impact on the core will amount to a substantial amount. The Gas Accord decision clearly contemplates that a full roll-in of Line 401 costs is contrary to the Commission's incremental ratemaking principles that existing customers should not have to pay for Line 401 costs.

There was also testimony in this proceeding that the price of gas is likely to remain high in the foreseeable future. In addition, PG&E recently announced that higher winter gas bills are expected because of the high cost of gas. When high gas costs are factored into the monthly bill of gas customers, together with

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[74] On rehearing, the Commission affirmed the use of this incremental ratemaking approach. (D.94-12-058 [58 CPUC2d at 420-421].)

the cost of a partial or full roll-in of Line 401 costs, core customers will experience rate shock.

One option that the Gas Accord recognized for a possible roll-in is if there was an "all-party settlement." However, none of the parties have proposed such a settlement for 2004. Without such a settlement it is clear that core customers do not willingly agree to a roll-in of Line 401 costs. Nonetheless, an all-party settlement regarding the roll-in costs of Line 401 would be encouraged.

Based on the regulatory history of Line 401, the commitments made by the Commission and PG&E, and our prior decisions, in combination with the additional costs that core customers will be saddled with if we adopt a partial, or eventual full roll-in of Line 401 costs, we are compelled to abide by our prior decisions. These considerations prohibit us from directing PG&E to move forward with a policy to roll-in the costs of Line 401 to the core.[75]

Based on the above discussion, PG&E's proposal to roll-in 20% of the Line 401 costs to the core is not adopted. In addition, the proposals of the other parties for a full roll-in of Line 401 costs is not adopted. The rates for 2004 shall not include any roll-in of costs on Line 401 to the core. At a time when it can be demonstrated that the core does experience substantial customer benefits because of the Line 401, the Commission may reconsider this issue in the next phase of PG&E's Gas Accord.

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[75] We note that the core is not getting a free ride on Line 401. To the extent core customers require service over Line 401, the core pays the associated costs for transporting the gas over Line 401.

2. Load Factor and Design Capacity

a. Position of the Parties

(1) CCC/Calpine

PG&E proposes to design its backbone rates using a system load factor of 68.4%. This load factor was calculated by dividing PG&E's system throughput forecast for 2004 by its system design capacity, with various adjustments for SMUD's equity capacity and firm off-system contracts. PG&E then uses this load factor to calculate all path-specific backbone rates, except for G-XF rates, which assume a 100% load factor.

Since PG&E is assuming the risk in 2004 for noncore local transmission and backbone revenues, CCC/Calpine assert that PG&E has dramatically understated its throughput and load factor forecasts. PG&E stands to benefit from the throughput and load factor that is in excess of its forecasts.

CCC/Calpine assert that PG&E's proposed calculation of its system load factor underestimates PG&E's ability to earn revenues from its backbone services. The witness for CCC/Calpine explained that under the Gas Accord structure, PG&E does not charge for backbone service solely on the basis of throughput. PG&E sells firm capacity, for which the utility collects demand charges regardless of whether the capacity is fully used. Many shippers pay demand charges in exchange for the assurance that they will have firm capacity when they need it. However, some firm shippers do not fully utilize their capacity, even though they have paid for that space through the demand charge. CCC/Calpine contend that a proper calculation of the system load factor should include the revenue associated with the demand charges.

In addition, PG&E's calculation of the system load factor must also account for the revenues associated with PG&E's marketing of as-available service, which results from the unused firm capacity that shippers have paid for through demand charges, but have not used. PG&E can charge up to 120% of the annual firm tariff rate for as-available service.

CCC/Calpine, CMTA, and Mirant propose to establish backbone rates in 2004 using a recommended system load factor of 81.3%. The calculation of the 81.3% load factor is explained at page 41, and shown in Table 9, of Exhibit 6. The system load factor of 81.3% is based on (1) PG&E's expected firm capacity sales in 2003, which is assumed to continue at a similar level in 2004; (2) an assumption that firm noncore shipper will use their firm capacity at an 88% load factor, based on the utilization rate for firm capacity during the Gas Accord; (3) as-available usage for the remaining volumes of the throughput forecast of CCC/Calpine, including the higher demand from electric generation; and (4) 120% weighting of as-available throughput to reflect the higher as-available rate.

CCC/Calpine point out that Table 8 of Exhibit 6 demonstrates that PG&E's system load factor based on throughput was 82% for the Gas Accord I period, and the load factor based on the sale of firm and as-available capacity was 93%.

Although TURN recommends a load factor for the backbone system of approximately 75%, TURN's witness agreed that the CCC/Calpine witness' method was the "next best approach."

(2) CMTA

CMTA contends that PG&E's load factor of 68.4% underestimates expected system throughput. CMTA contends that by using a lower system throughput figure, this underestimates PG&E's ability to recover its backbone revenue requirement, and its ability to earn revenues from selling backbone services.

CMTA states that backbone rates should use a load factor that is based on the percentage of its backbone services that PG&E will sell in 2004, instead of just throughput. CMTA supports the load factor of 81.3% that CCC / Calpine witness Beach developed.

(3) CAPP

Although CAPP supports the continued use of the basic framework of the Gas Accord structure, CAPP believes there are some deficiencies with the current structure. Most notable is the use of a rate design that has not efficiently or equitably allocated the costs of PG&E's backbone transmission paths to the users of those paths, which results in significant cross-subsidization among the transportation paths. CAPP contends that in order for Northern California to enjoy the ample supply of Canadian gas, the rates for backbone transportation service must accurately reflect the cost and utilization of the facilities, *i.e.*, there must be cost-based transmission rates.

CAPP proposes a rate design proposal comprised of three elements. The first element is to implement a consistent, harmonized approach to the design of rates for the two principal backbone transmission paths, the Baja and Redwood paths. CAPP proposes that there be a path-specific allocation of costs, matched by the use of path-specific load factors to derive rates. The second element is the full integration, or roll-in, of the Line 400 and 401 costs.[76] CAPP contends that a full roll-in will reflect the actual impact of those facilities. The third element, in the event path-specific load factors are not used, is to use a postage stamp rate with a higher overall load factor to derive PG&E's rates.

[76] CAPP's position on the roll-in of costs is set forth in that section.

Under the current rate design, path-specific capital costs are utilized to design path-specific rates using a system-wide average load factor. CAPP contends that a path-specific load factor must be used if path-specific costs are used to develop rates. CAPP, therefore, recommends a cost-based rate design for each of the two major supply transportation routes. The alternative is to adopt system-wide average costs with system-wide average throughput, *i.e.*, a postage stamp backbone rate.

CAPP points out that the Redwood Path includes the relative higher capital costs associated with Line 401. Those costs are higher due to the fact that it is much newer, and therefore less depreciated than the Baja Path facilities. CAPP also points out that the load factor on Line 401 is based on the use of a system-wide load factor. However, the Redwood Path is highly utilized, which generates a higher system average load factor. Since the Redwood Path has a much higher utilization rate than the other paths on the California transmission system, the rates for service on the Redwood Path should be relatively lower, all other factors being equal.

Using illustrative 2004 costs and projections of path-specific throughput from the 2002 California Gas Report (CGR), CAPP contends that Baja rates should be 39 cents/Dth higher than Redwood rates if both path-specific costs and throughput were employed in the rate design. Under PG&E's proposal, utilizing path-specific costs and system-wide average throughput, PG&E's Redwood Path rates would produce a 10.8 cents/Dth premium for Redwood service compared to Baja. CAPP contends that PG&E's proposed rate design favors Southwest gas supply, and Redwood Path shippers subsidize the costs of Baja Path service. This cross-subsidization can be eliminated by using path-based load factors.

CAPP's primary recommendation is to use path-specific load factors. For the Redwood Path and Baja Path, CAPP recommends path-specific load factors of 93% and 55%, respectively. For the Silverado and Mission paths, CAPP recommends a path-specific load factor of 84%.

CAPP's proposal would reverse the Redwood Path differential from a premium to a 6 cents/Dth discount. Under the CAPP proposal, path-based rates would incorporate a multi-year average load factor for each of the various paths.

PG&E recommends that CAPP's proposal to use path-specific load factors be rejected because the rates resulting from the CAPP proposal would increase costs to California end-use customers by raising the Topock transport rate $0.055 Dth higher than PG&E's proposed Topock rate. CAPP contends that PG&E's argument assumes that Topock is usually the marginal supply for gas transported to Northern California. CAPP contends that it is no longer factually correct or reasonable to assume that Topock is or will remain the marginal source of supply into Northern California. CAPP points out that Exhibit 13 shows that Malin has been the marginal supply 43% of the time since the Gas Accord has been in effect.

TURN opposes CAPP's proposal to employ path-specific load factors for computing Baja and Redwood transmission rates because TURN asserts it will result in highly unstable rates. CAPP contends that its proposal used load factor figures, which incorporated a range of different operating conditions and over a wide period. Such an approach dampens the effects of variability in usage patterns, and generates rates that are stable. CAPP points out that a system-wide load factor is the sum of the path-specific load factors. Thus, any instability that affects path-specific load factors, also relate to the system-wide load factor as well.

CAPP contends that PG&E's load factor forecast for 2004 of 68.4% is grossly understated, and should not be treated as a credible figure for ratemaking purposes. If PG&E's forecast is adopted, this will allow PG&E to over collect revenues.

CAPP asserts that the actual system utilization during the Gas Accord has exceeded PG&E's 68.4% load factor. Third party forecasts project system utilization for PG&E at a significantly higher level. For example, the California Energy Commission's December 2002 publication entitled "Natural Gas Supply and Infrastructure Assessment," forecasts throughput of 2,546 MMcf/d for 2004, which results in a load factor of 75%. According to PG&E, the CEC's forecast is considered conservative based on the track record of CEC in its forecasts of system throughput.

CAPP also asserts that PG&E's argument that off-system throughput will fall below historical levels in 2004 is not supported by PG&E's own observation that the historical price spreads between Malin and Topock are expected to continue. CAPP asserts that these price spreads drive the transportation market for off-system capacity.

In the event the Commission does not approve CAPP's path-specific rate design proposal, CAPP recommends that a single, system-wide postage stamp rate be adopted in 2004, with a 79% load factor. The completely rolled-in postage stamp rate would be $0.23 per Dth.

CAPP's load factor of 79% takes into account the fact that shippers that subscribe to firm backbone service can pay for capacity on a straight-fixed variable rate design, but do not utilize capacity at full contract volumes. To the extent that PG&E is able to sell as-available service from capacity that has been sold as firm service under the straight fixed variable rate design, the pipeline is compensated twice for the sale of such volumes.

PG&E criticizes CAPP's use of a 79% load factor. CAPP asserts that PG&E's argument relies on two false premises. The first premise that PG&E relies on is that because of the advent of combined cycle generating units, this has resulted in lower gas consumption. CAPP points out that to the extent that this has been the case, then the consumption data for the period in which that technology has been in place will already incorporate this development. Thus, CAPP's approach did not ignore this change in electrical generation technology from 1998 to 2002, the period when this technology is supposed to have begun, because CAPP used these demand numbers for that historical period.

The other premise that PG&E uses to criticize CAPP's load factor is that CAPP only used data from five years, which according to PG&E did not give the widest possible range of historical and expected market conditions. CAPP asserts that the data from 1998 to 2002 is the most relevant because that is when the market operated in an unbundled environment. Unbundling simply was not in place for the periods prior to 1998.

(4) Mirant

PG&E's design of backbone rates is based on a system load factor of 68.4%, which is far below the 87.5% load factor in the Gas Accord settlement. PG&E's lower system load factor supposedly "reflects the recent changes in gas and electric demand, primarily reflecting conservation efforts and a slower economy." (Ex. 3, p. 14-15.)

Mirant contends that PG&E has failed to justify the use of a lower system load factor. As pointed out by the witness for CCC / Calpine, PG&E's past forecasts have underestimated actual electric generator demand. Also, PG&E's

estimate of off-system throughput is understated. Mirant recommends that the CCC / Calpine witness' recommendation for an electric generator / cogeneration demand forecast of 930 MDth / d, and an off-system throughput forecast of 298 MDth / d, be adopted.

The testimony of the CCC / Calpine witness also challenged PG&E's proposal to set rates based solely on a throughput-based system load factor. Beach noted that PG&E sells firm and as-available backbone services, and does not charge rates solely for volumes of throughput. Mirant supports the system average load factor of 81.3%, instead of PG&E's proposed factor of 68.4%. TURN witness Florio considered the 81.3% load factor proposal to be the next best approach. TURN also agreed with the CCC / Calpine witness' recommendation for a higher electric generator throughput.

(5) NCGC

PG&E proposes to design rates on the basis of a forecasted system load factor of 68.4%. PG&E's low load factor is due, in large part, to the low electric generator throughput projected by PG&E on the basis of an assumption about new power plants outside of PG&E's service territory.

NCGC points out that PG&E's system load factor is substantially below the 87.5% load factor assumption that is currently used for designing backbone rates. NCGC urges that the projected load factor proposed by PG&E be revised to reflect any revision in an updated electric generator throughput forecast. NCGC witness Pretto stated that a reduced system load factor could become a self-fulfilling prophecy by causing higher transportation rates, which could reduce electric generator throughput in PG&E's service territory.

NCGC is concerned about PG&E's proposed 68.4% load factor because it is inconsistent with historical experience. During the first four years of the Gas

Accord, the Redwood and Baja paths operated at a combined capacity factor of 81%, 79%, 88% and 91%, respectively. (*See* Ex. 1, p. A4-5.) During the fourth year (March 1, 2001 through February 28, 2002) the combined unused capacity on these paths was only 9%, or 265 Mdth/d. The Redwood path was utilized at an especially heavy load factor. Scheduled volumes on the Redwood path equaled 97% of firm capacity in the first and second years of the Gas Accord, 100% in the third year, and 95% in the fourth year. PG&E's throughput forecast of 68.4% for 2004 is inconsistent with the historical experience of the Gas Accord.

NCGC states that CCC/Calpine, CMTA, and Mirant propose adjusting PG&E's load factor to reflect demand-charge based sales of firm backbone capacity. NCGC agrees that since demand charges were paid for the capacity, the demand charge revenues should be considered in calculating the load factor. NCGC also contends that the revenues from modified fixed variable (MFV) contracts, and revenues from straight fixed variable contracts, should be considered in calculating the load factor as well. If a customer takes firm capacity under an MFV rate but fails to use the capacity, it would be improper to calculate the backbone load factor and rate as though the capacity generated no revenues.

NCGC also favors CAPP's proposal for a postage stamp rate. CAPP noted that the least defensible feature of the Gas Accord backbone rate design was the asymmetrical use of path-specific costs in combination with a system-wide average load factor to develop path-specific rates. NCGC states that there has been a substantial shift in supply basin and pricing relationships. Given today's market structure, and a full roll-in of rates, NCGC believes that a postage stamp rate would benefit all customers by facilitating gas-on-gas competition between Southwest and Canadian supply basins.

(6) SMUD

PG&E's proposal to reduce the load factor on the backbone system from 87.5% to 68.4% is perplexing to SMUD because it has been requesting for quite some time for PG&E to sell more pipeline capacity to SMUD. If PG&E expects the pipeline to be so underutilized, SMUD is willing to pay over book value for additional backbone capacity. SMUD recommends that the Commission either adopt a load factor based on the volume of capacity sold, instead of PG&E's proposed load factor reduction based on projected throughput, or order PG&E to sell surplus backbone capacity to SMUD.

(7) TURN

PG&E proposes to design backbone rates based on a projected system load factor of 68.4%. Although setting rates based on projected throughput is typical ratemaking practice, TURN contends that such practice should not apply in a situation such as this, where PG&E has formally accepted the risk of under-subscription and underutilization of Line 401.

In the first Expansion Project rate case for Line 401, A.92-12-043, the parties and the then-Commissioners debated the scope of risks that PG&E undertook when it elected to construct the Expansion Project. While a bare majority of the commissioners decided that PG&E had not accepted the risk of stranded costs resulting from the construction of Line 401, all of the commissioners agreed that, without question, PG&E had accepted the risks of under-subscription and underutilization associated with Line 401. Firm service rates for Line 401 were set based on a 95% load factor to reflect that assumption of risk by the project sponsor. (D.94-12-058, p. 9)

In the Gas Accord settlement, TURN asserts that the load factor of 87.5% reflected the parties' positions on PG&E's assumption of risk of the undersubscription and underutilization of its facilities.

TURN points out that PG&E is at risk for all of its backbone transmission costs, but the use of PG&E's system load factor, which is based solely on expected usage, ignores PG&E's prior commitments, and removes the risk of overbuilding and the underutilization that PG&E undertook. To resolve this, TURN witness Florio recommends the use of an adjusted system load factor that imputes 95% utilization of the expansion project, while assuming a throughput-based load factor for the remainder of the system. A single system-wide adjusted load factor would then be used to set actual backbone rates for each of the paths, as was done in the Gas Accord. TURN's adjusted system load factor is calculated at 75.7%.[77] TURN recommends that the Commission adopt a single system-wide load factor of at least 75.7% for the purpose of setting rates for backbone transmission. TURN points out that the CCC/Calpine derivation of the system load factor of 81.3% is similar to the approach taken by Florio to arrive at the 75.7% system load factor.

The CAPP witness advocates the use of path-specific load factors, rather than an overall system load factor, for setting various path rates. TURN recommends that the proposal be rejected, and that a single system-wide load factor be used. TURN contends that any attempt to base path-specific rates on assumed future throughput levels would produce highly unstable rates, unless the initial forecast were left in place even as conditions change. TURN asserts

[77] To the extent that the underlying demand forecast is modified, this percentage would change.

that no one can say with any certainty that one supply area will continue to be more attractive. Locking in rates with path-specific load factors would tend to stifle, rather than promote, competition among gas supply regions.

(8) PG&E

CCC/Calpine propose that a load factor of 81.3% be adopted. PG&E asserts that this load factor fails to adjust for a reduction in off-system delivery of 66.5 MDth, and fails to adjust the unused firm capacity for 76.6 MDth/d, which represents the volumetric component of the MFV capacity. In addition, the CCC/Calpine load factor overstates the electric generator demand forecast. If these adjustments are made, PG&E asserts that the proposed load factor of CCC/Calpine would more closely align with PG&E's proposed 68.4% load factor.

PG&E also asserts that the proposal of CCC/Calpine to calculate a system load factor based on expected revenues from backbone services is impractical, given the variety of service options PG&E offers to customers. Since the majority of backbone revenues may continue to be recovered on a volumetric basis, the risks of revenue volatility require a throughput based load factor.

PG&E points out that CAPP's path-specific load factor would result in a Topock rate that is $.055/Dth higher than PG&E's proposed Topock rate. PG&E contends that CAPP's proposed path-specific load factor is likely to increase costs to California consumers by increasing the transportation rate on the marginal path, the Baja Path. PG&E recommends that CAPP's path-specific load factor be rejected.

PG&E contends that TURN's proposal to bifurcate the load factor to design a portion of the Redwood path rates at 95% is without merit. PG&E says the record lacks the evidence to justify a bifurcated load factor calculation for on-system Redwood path rates.

PG&E proposes to design backbone rates using the system average load factor, using the 2004 demand forecast with certain adjustments, and divided by the firm design capacity. This results in a 68.4% load factor. PG&E proposes to exclude from the electric generator demand forecast 45 MDth/d of SMUD equity and 101 MDth/d of load served by third party private pipelines. PG&E also proposes to include a backbone throughput adjustment of 45.9 MDth/d to account for premiums and discounts on backbone transmission.

PG&E's lower load factor for 2004 reflects the recent charges in gas demand, resulting primarily from conservation efforts, a sluggish economy, and lower electric generator demand. PG&E asserts that its backbone load factor proposal represents a reasonable balance of risks and rewards, and sends the appropriate pricing signals to the market. Given PG&E's rate design, and the low expected level of capacity subscription in 2004, a system throughput based load factor is the only practical and reasonable method to design firm backbone rates. The Commission should adopt PG&E's proposal.

b. Discussion

The forecast of gas throughput is a key element in the calculation of PG&E's gas transportation rates. The most contested elements of PG&E's 2004 throughput forecast in this proceeding are the forecasts of electric generator gas demand, which impacts both backbone and local transmission rates, and off-system throughput, which impacts backbone rates. PG&E's backbone system load factor is also in dispute, which affects backbone rates. The demand forecast of electric generator and off-system deliveries have been discussed earlier in this decision.

In the Gas Accord Settlement Agreement, a load factor of 87.5% was agreed to, which was used to calculate the firm annual on-system backbone transmission charges. As-available rates, and firm seasonal capacity charges were based on the firm annual on-system backbone charges. The Malin to off-system firm rates were calculated using incremental Line 401 costs and a 95% load factor. (73 CPUC2d at 821.)

PG&E and the other parties have come up with four different ways of calculating the load factor.

PG&E's load factor of 68.4% was developed using PG&E's adjusted demand forecast of 2,184.926 divided by the total (3195.292) of the net firm design capacities of each path, as shown in Table 14.4 of Exhibit 3.

The use of the net firm capacity of 3195.292 as the denominator for the load factor is a departure from the design capacities used in the Gas Accord. In the Gas Accord, costs were allocated to each path based on a pro rata share of the firm design capacities of each path. As shown in Table 14-3 of Exhibit 3, for Line 401, only 380.6 MDth/d was used to design on-system (non-vintage) 2002 Redwood Path rates. In contrast, PG&E proposes to use 870.1 MDth/d of Line 401 capacity to design the 2004 on-system Redwood Path rates. A portion of the 870.1 MDth/d comes from the recent Line 401 expansion capacity, while the rest comes from the remaining capacity on Line 401.

Using PG&E's adjusted demand forecast of 2184.926 and the denominator of 3195.292, PG&E's calculation of the load factor is 68.4%. If PG&E's adjusted demand forecast of 2184.926 is divided by a denominator of 2759.6, the load factor would be 79.2%.

The second load factor proposal is sponsored by CCC/Calpine, CMTA, and Mirant. They recommend the adoption of a load factor of 81.3%, as shown in Table 9 of Exhibit 6. This load factor is based on the percentage of the backbone services that PG&E is expected to sell in 2004. This load factor also accounts for the higher electric generator forecast that the CCC/Calpine witness Beach recommends.

The third load factor proposal is sponsored by CAPP. CAPP's primary recommendation is to establish path-specific rates, including a single Redwood rate applicable to both core and noncore customers. CAPP proposes that if its proposal for path-specific rates is adopted, the load factor on the Redwood Path should be 93%, a 55% load factor for the Baja Path, and for the Silverado and Mission paths a load factor of 84%. CAPP's derivation of the load factors is set forth in Table 1 of Exhibit 30.

If the Commission does not adopt CAPP's proposal for path-specific rates, CAPP's secondary recommendation is that the Commission approve a rolled-in postage stamp rate, i.e., a single average rate for all paths, using a load factor of 79%. The 79% takes into account the marketing of backbone services during the Gas Accord period, and is based upon a total demand forecast of 2367 MDth/d, and a denominator of 2987.[78] Under this secondary proposal, the single average rate would be $0.23 per Dth.

The fourth load factor proposal is sponsored by TURN. TURN recommends that a load factor of 75.7% or greater be adopted. TURN's load factor proposes to adjust the usage on Line 401 to reflect the risk of under-subscription and underutilization that PG&E had agreed to when Line 401 was built. In D.94-12-058 (58 CPUC2d 417), firm service rates for Line 401 were set

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[78] If CAPP's demand forecast of 2367 is divided by PG&E's denominator of 3195.292, the load factor would be 74.1%.

based on a 95% load factor to reflect the assumption of the risk by PG&E in constructing Line 401. In the Gas Accord, the load factor of 87.5% was agreed to by the parties and adopted. TURN contends that the 87.5% reflected, among other things, the assumption of the risk by PG&E.

If PG&E is allowed to use a system load factor based solely on expected usage, TURN contends that this would remove the risk of overbuilding and underutilization that PG&E undertook when Line 401 was built. To reflect this risk, TURN proposes that Line 401 usage be adjusted by imputing 95% utilization of the Line 401 Expansion Project, while assuming an adjusted throughput-based load factor for the rest of the system. The adjusted load factor would be used to set actual backbone rates for each of the paths.

To derive PG&E's adjusted load factor, several steps are involved. First, TURN would use the difference between the 95% utilization and the load factor resulting from the adjusted demand forecast divided by the total net firm capacity number of 3195.292, and multiply that difference by the net firm capacity of Line 401 of 875.463.[79] Second, the product resulting from the multiplication would then be added to the adjusted demand forecast. And third, that sum would then be divided by the total net firm capacity of 3195.292 to arrive at the adjusted load factor. The adjusted load factor would then be used for setting the backbone rates.

In reviewing the demand forecasts and the different methods of calculating the load factor, it is apparent that the load factor we adopt will affect

[79] The Line 401 net firm capacity number of 875.463 is derived from using the firm delivery capacity of 1003.606 minus 86.424 for G-XF off-system contracts and 41.719 of SMUD's equity interest in Line 401. (See Ex. 43, p. 10; Ex. 3, Table 14-6.)

PG&E's ability to recover the adopted revenue requirement. As parties point out, PG&E prefers a lower load factor because it allows more costs to be spread over a smaller amount of throughput. Other things being equal, a lower load factor means higher rates. If PG&E is able to recover its revenue requirement, any revenues in excess of the revenue requirement benefits its shareholders since PG&E is at risk for any under-recovery or over-recovery. Other parties prefer a higher load factor so that costs can be spread over a larger amount of throughput, thus lowering rates. A higher load factor makes it more difficult for PG&E to recover its revenue requirement because it must sell more capacity.

The load factor result can be changed in a number of different ways. For example, the load factor result can be altered by raising or lowering the demand forecast,[80] using a different net firm capacity amount, making adjustments to the utilization of a particular path, or accounting for the extra revenue generated by the sale of as-available capacity. All four-load factor proposals reflect these kinds of possible adjustments.

Before deciding which load factor method and number we should adopt, we need to address the primary and secondary recommendations of CAPP.

CAPP's primary proposal is that path-specific rates be adopted. CAPP contends that this will equalize gas competition because each path will have its own load factor, and it will eliminate the price difference, which favors Southwest gas. Under CAPP's proposal, the costs of Lines 400 and 401 would be

[80] For example, we could, as suggested by several parties, increase the electric generator demand forecast to reflect the postponement of new combined cycle plants, which should increase gas usage at existing gas-fired plants. This would result in a higher load factor.

completely rolled-in, and the Redwood Path rate would be $0.221 per Dth. The Baja rate would be $0.282, and Silverado and Mission would be $0.113.[81]

CAPP's secondary proposal is for a single, average rate for all paths, often referred to as a postage stamp rate. This proposal also calls for the roll-in, or averaging of the costs of Lines 400 and 401.

Since we do not adopt the proposal of PG&E and the other parties to partially or fully roll-in the costs of Line 401 to the core, CAPP's proposal for a path-specific rate for the Redwood Path and other path-specific rates, is not adopted. In addition, since the postage stamp rate proposal depends on a single, average rate for all paths, which we do not adopt due to the non-roll-in of Line 401, the proposal for a postage stamp rate is not adopted. We also note the concern of PG&E and TURN that path-specific rates are likely to raise costs by increasing the transportation rate on the Baja path, and that path-specific rates are likely to hinder competition rather than promoting competition.

We turn next to the load factor proposals of CCC/Calpine, TURN, and PG&E. CCC/Calpine's proposal is designed to account for the sale of all backbone services that PG&E is expected to sell in 2004, rather than a load factor based on expected system throughput. TURN's proposal is similar to the proposal of CCC/Calpine in that it is designed to adjust the throughput on Line 401 for the risk that PG&E took when it built Line 401. PG&E's load factor is the lowest of all the proposed load factors, and is based on its demand forecast with certain adjustments.

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[81] CAPP's path specific rates would cause the firm Baja usage charge to increase by $0.23 to $0.278 per Dth over 2003 rates, and the firm Redwood usage charge to increase by $0.106 to $0.214 per Dth.

In order for us to decide on which load factor method and load factor amount should be adopted, it is useful to compare the proposed load factors with the actual load factors in prior years. As shown in Table 1 of Exhibit 30, the testimony of the CAPP witness, the load factors for 1998, 1999, 2000, 2001 and 2002 were 78%, 77%, 81%, 89% and 79%, respectively.[82] PG&E's load factor of 68.4% is quite a bit below the historical load factors that were experienced during the Gas Accord. If we adopt PG&E's demand forecast without any adjustment, and its load factor method and percentage, the likelihood that PG&E will recover its revenue requirement is high in light of the historical load factors.

The difference in load factors is even more pronounced when the CCC/Calpine table showing the "load factor based on services sold" is used as a comparison. According to Table 8 of Exhibit 6 (page 2 of 2), the load factors based on services sold were 86%, 86%, 93%, 101% and 97% in 1998, 1999, 2000, 2001, and 2002, respectively.

PG&E contends that its load factor percentage should be adopted because its "lower load factor reflects the recent changes in gas and electric demand, primarily reflecting conservation efforts and a slower economy." (Ex. 3, p 14-15.) The parties who propose a higher load factor contend that PG&E has underestimated its demand forecasts of electric generator and off-system deliveries, which results in a lower load factor. In addition, they contend that PG&E's load factor fails to take into account revenues from the sale of as-available services.

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[82] The load factors shown in Table 8 (page 2 of 2) of Exhibit 6, the testimony of CCC/Calpine's witness, are slightly higher in four of the five years as compared to the CAPP table.

Based on the load factors experienced during the Gas Accord period, and the need for just and reasonable rates while providing PG&E with the opportunity to recover its costs and a reasonable rate of return, we believe that a load factor higher than what PG&E proposes should be adopted.

As discussed in the demand forecast, we adopted the adjustment to off-system deliveries to reflect the likelihood that off-system deliveries will remain unchanged or increase. This adjustment to off-system deliveries, using PG&E's load factor method, works out to a load factor of 70.85%.[83] This load factor is still below the load factors experienced previously. This comparison suggests that the demand forecast is too low, or that PG&E has underestimated its ability to market its backbone services. PG&E's load factor of 68.4% also suggests that there may be excess capacity, which could be sold to an entity such as SMUD.

To achieve a balance between just and reasonable rates, and to provide PG&E with the opportunity to recover its costs and a reasonable rate of return, an adjustment should be made to the load factor so that it correlates more closely to the load factors experienced during the Gas Accord period. Such an adjustment is warranted because PG&E's proposed load factor is inconsistent with past usage on PG&E's transmission system.

For this purpose, TURN's load factor method should be used. In reviewing D.90-12-119 (39 CPUC2d 69), D.94-02-042 (53 CPUC2d 215) and

[83] The 70.85% load factor is calculated by adding the additional 79 MDth/d of off-system deliveries to PG&E's demand forecast as shown on Table 14-6 of Exhibit 3, resulting in an adjusted demand forecast of 2263.926 MDth/d. The adjusted demand forecast is then divided by the net firm capacity of 3195.292.

D.94-12-058 (58 CPUC2d 417), we agree with TURN that PG&E's shareholders were placed at risk for the Line 401 costs and revenues "as a condition of the 'let the market decide' policy."[84] (58 CPUC2d 420-421.) If PG&E's load factor of 68.4% is adopted for all of its transmission system, PG&E is no longer being held to account for the risk that it took on when Line 401 was authorized. That is, the risk associated with Line 401 gets diluted if PG&E's load factor method is adopted.

The utilization factor of 95% that TURN uses comes from D.94-02-042, the proceeding in which rates were authorized for Line 401. That load factor was adopted to calculate firm service rates, and to recognize that the risk of recovery of the costs of Line 401 was to reside with PG&E's shareholders. (53 CPUC2d at 226, 230, 237; 58 CPUC2d 423.) The Commission stated "It is abundantly clear that any lower load factor will shield PG&E from the risks of unused capacity." (53 CPUC2d at 237.) In the Gas Accord, the parties agreed that the firm on-system backbone transmission charges should be based "on an annual average capacity factor of 87.5 percent." (73 CPUC2d 821.)

We note that the 95% load factor is very close the load factors experienced on the combined Redwood paths during the Gas Accord period. For 1998, 1999, 2000, 2001 and 2002, the combined Redwood Path load factors were 95%, 92%, 96%, 93% and 91%, respectively. (Ex. 30, Table 1, p. 11.)

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[84] One of PG&E's arguments regarding the roll-in of Line 401 is if an alternate pipeline had been built, it is unlikely that as much capacity as Line 401 would have been built because "there was a considerable amount of slack capacity on PG&E's system until mid-2000…." (Ex. 4, p. 3-9.) This statement about slack capacity supports TURN's argument that PG&E faced the risk that the Line 401 would be underutilized, which in turn supports the use of TURN's load factor adjustment to Line 401.

Using TURN's method of adjustment, and the off-system delivery adjustment that we made in the demand forecast, the system load factor upon which backbone rates shall be based is 77.02%. This load factor is calculated as follows. In order to derive the load factor used to adjust the Line 401 throughput to reflect PG&E's risk, we added the additional off-system delivery of 79 MDth / d to PG&E's adjusted demand forecast of 2184.926 shown in Table 14-6 of Exhibit 3. The sum of those two numbers is 2263.926. Dividing 2263.926 by the total net firm capacity of 3195.292 results in a load factor of 70.9%. To account for the risk that PG&E undertook with respect to Line 401, the difference of .95 and .709 results in .241. The .241 is then multiplied with the net firm capacity of Line 401 of 875.463, resulting in an adjustment of 210.99. The 210.99 is then added to the adjusted demand forecast of 2263.926, resulting in the sum of 2474.916. The 2474.916 is then divided by the net firm capacity of 3195.292 to arrive at the system load factor of 77.02%. [85]

For the purpose of designing backbone rates for 2004, the load factor of 77.02% is adopted. This load factor is at or below the load factors experienced on PG&E's transmission system during the Gas Accord period, and represents an equitable balance between just and reasonable rates, while providing PG&E with a reasonable opportunity to recover its revenue requirement.

PG&E shall continue to be at-risk for throughput and revenues on its backbone transmission system.

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[85] The system load factor of 77.02% has been adjusted slightly from 77.46% to reflect the corrections proposed by PG&E to the tables shown in Appendix A of the proposed decision, in response to the November 25, 2003 ALJ ruling.

PG&E's total net firm capacity is based on the firm design capacities of each backbone path, as shown in Table 14-4 of Exhibit 3. That total is used to calculate the load factor, and to allocate the costs to the backbone paths. No one raised any objection to the use of these firm design capacities to allocate the costs to the backbone paths, or to use it as the denominator for calculating the load factor. We adopt those firm design capacities in Table 14.4 of Exhibit 3, and shall permit them to be used to allocate costs to the backbone paths, and for use in the denominator to calculate the adopted load factor of 77.02%.

PG&E proposes that the Redwood Path off-system rate be set to equal to the on-system rate. The reason for this change is because all of the Redwood Path capacity is being used to design on-system rates. No one objects to this proposal.

Under the Gas Accord, Redwood off-system rates are calculated using the incremental Line 401 costs and a 95% load factor. Since we have adopted the firm design capacities shown in Table 14-4 of Exhibit 3 to allocate costs to the backbone paths, we will adopt the proposal that the Redwood off-system rate equal the Redwood on-system rate.

PG&E proposes to assign vintage Redwood capacity to core retail and core wholesale as shown in Table 14-5 of Exhibit 3. We adopt PG&E's proposal.

PG&E makes reference at page 14-12 of Exhibit 3 that the "Non-vintage Redwood Path and Baja backbone capacity is assigned to meet each core customer's 1-in-10 year demand requirements." This passage is related to the core Winter Firm Capacity Requirement referenced at page 4-9 of Exhibit 3. Since we do not adopt the Winter Firm Capacity Requirement, the assignment of capacity on the non-vintage Redwood Path and Baja Path to meet the Winter Firm Capacity Requirement is not needed, and shall not be adopted. PG&E shall instead assign core capacity on the paths to meet the current guidelines, which is close to a 1-in-3 year cold temperature event.

PG&E proposes that the Schedule G-XF rates continue to be designed on an incremental basis in accordance with D.94-02-042 (53 CPUC2d 215.) We adopt PG&E's proposal.

PG&E makes reference at page 14-15 of Exhibit 3, and in its proposed tariffs, that the backbone rates are subject to the contingency rate adjustments that PG&E has proposed. However, as discussed in the contingency adjustment section of this decision, we do not adopt all of the adjustment mechanisms that PG&E is proposing.

Based on the proposals that we adopt, as discussed above, the backbone rates attached to this decision in Appendix A, Tables 3 to 9, shall be adopted as the backbone rates in this proceeding.

C. Storage Cost Allocation and Rate Design

1. Discussion

As mentioned in the Storage Services section of the decision, we have revised the assignment of capacities for Core Firm Storage, Standard Firm Storage, and Balancing. The revisions to the injection, inventory, and withdrawal capacities of those three service is due to the non-adoption of certain PG&E proposals, as previously discussed. Table 4 in the Storage Services section of this decision sets forth the assignments that we use for allocating the storage cost of service.

PG&E proposes to continue the storage rate design structure for Core Firm Storage. The core storage rate will continue as a single monthly capacity charge, and reflect the core's allocation of the storage costs. The core firm storage rate is shown in Table 10 of Appendix A.

For customers taking service under Schedule G-SFS, PG&E proposes to combine the capacity charge and the withdrawal charge into a single capacity charge. No one has objected to this proposed change. PG&E's proposal to combine the two charges is adopted.

PG&E proposes no changes to the negotiated firm or negotiated as-available storage services, or to parking and lending services.

The rates for G-SFS, negotiated firm, negotiated as-available, and parking and lending are shown in Table 10 of Appendix A.

The storage costs allocated to pipeline load balancing will continue to be bundled in all backbone transmission rates.

PG&E proposes to continue the self-balancing option. PG&E's design of the self-balancing credit is based on 80% of the total storage balancing assets. Those who elect self-balancing would receive a credit of $0.010 per dth, instead of the current $0.005. This is shown in Table 13 of Appendix A. We adopt PG&E's proposal to continue the self-balancing service option for 2004 and 2005.

D. Local Transmission

1. Four-Tier Noncore Proposal and Backbone level Rate Structure

a. Position Of The Parties

(1) CCC/Calpine

CCC/Calpine propose the creation of a backbone level rate structure, which is also referred to as a backbone level rate. Under this proposal, customers that connect directly to PG&E's backbone pipeline system and, as a result, do not receive any local transmission service, will pay a backbone level rate that does not include local transmission costs. CCC/Calpine contend that such a rate will end the current subsidy of local transmission customers by backbone level customers, and ensure that backbone level customers do not have to pay for services that they do not receive. CCC/Calpine also assert that the backbone level rate proposal will better align PG&E's local transmission rates with the cost to serve local transmission customers, and fully complies with the applicable law.

CCC/Calpine assert that PG&E's proposal for a four-tier local transmission rate structure perpetuates the cross-subsidies that currently exist, and creates new ones. Under PG&E's proposal, the largest customers will still be obligated to pay a significant sum for local transmission service that they do not receive. They also assert that PG&E's proposal fails to comply with the requirements of §§ 453(a) and 454.4, which requires that cogenerator rates be set in parity with the rates of other electricity generators and prohibits undue preferences in the setting of rates.

CCC/Calpine recommend that the Commission reject PG&E's four-tier local transmission rate proposal for a number of reasons.

First, CCC/Calpine assert that PG&E's proposal is not based on a customers' actual cost-of-service. Although PG&E claims that its four-tier proposal is justified because a customer's cost-of-service decreases as a customer's size increases, PG&E has not demonstrated that customer size is an actual driver of PG&E's cost to provide local transmission service. CCC/Calpine assert that PG&E's proposal relies on an unproven and erroneous correlation between the customer's size and cost of service. For example, if size drives the cost of service, one would expect under PG&E's proposal, that the smaller Tier 2 customer should pay much more than the larger Tier 3 customers. However, under PG&E's proposal, the rates of Tier 2 and Tier 3 customers are virtually identical.

CCC/Calpine contend that under PG&E's proposal, small customers with high load factors or that are located close to the backbone end up paying a more expensive rate than under the Gas Accord. Large customers with lower load factors, or that are located far from the backbone, get a rate decrease, which is not merited in light of their heavier use of the local-transmission system. CCC/Calpine assert that the local transmission rates proposed by PG&E simply do not correlate with cost of service.

CCC/Calpine also point out that PG&E's only cost study regarding its local transmission proposal is based exclusively upon distance from the backbone and the cost to connect to the backbone, not size related cost differences. CCC/Calpine assert that PG&E's cost study is riddled with methodological inconsistencies, including the failure to demonstrate why customers located the same distance from the backbone with a similar cost of service should have dramatically different rates. CCC/Calpine also contend that the failure to include Duke's Morro Bay plant in the study biased the results in favor of unduly lowering rates for larger customers.

CCC/Calpine contend that PG&E's four-tier proposal cost study did not address economies of scale.

TURN stated that PG&E's four-tier proposal is completely arbitrary because PG&E uses the unorthodox mechanism of setting arbitrary rates for certain noncore customers before allocating costs among core and noncore.

CMTA agrees that PG&E has not demonstrated that size drives costs, and that PG&E's proposed local transmission rates are arbitrary. ORA and DGS are also opposed to the proposal. Due to the fact that so many parties agree that the PG&E's local transmission proposal is arbitrary, unjustified, and will not discourage bypass of PG&E's local transmission system, the Commission should reject the PG&E local transmission proposal.

CCC/Calpine's second reason for rejecting PG&E's proposal is that it continues existing subsidies, creates a new level of improper subsidies, and unfairly impacts competition in the electricity market. Customers who have built and paid for their own laterals to PG&E's backbone system for backbone level service, would under PG&E's proposal, be required to pay a rate that includes a full local transmission component. Paying for a service that customers do not use, results in backbone level customers having to subsidize the rates of other electricity generators who receive local transmission service from PG&E, such as Duke. This subsidy by backbone level customers provides Duke, and other similarly situated customers, with an unearned competitive advantage of a subsidized rate and no capital investment in pipeline infrastructure. If PG&E is allowed to charge its electricity generators the PG&E local transmission rate of $0.075 to $0.157 per Dth, the cost of production will be inflated for merchant generators that are located close to PG&E's backbone system. As a result, these merchant generators will be less able to compete with a local transmission generator who enjoys a subsidized gas transportation rate. In addition, under PG&E's proposal, smaller electric generators with relatively high load factors, or that are located close to the backbone, will have to pay unduly high local transmission rates and subsidize the rates of larger customers with lower load factors, or who are located further from the backbone. This also has an unfair effect upon competition in the electricity market.

CCC/Calpine's third reason for rejecting PG&E's proposal is that it requires backbone level customers to pay for local transmission that they do not use, and these customers will continue to seek a backbone level rate or other mechanism that properly reflects their true cost-of-service. Under PG&E's proposal, backbone level customers would be charged 7.5 cents in Tier 4, and 15 cents in Tier 3 for local transmission service these customers do not use. The proposed local transmission charges make up 61% and 75% of a Tier 4 and Tier 3 backbone level electric generator's total rate. CCC/Calpine assert that the adoption of PG&E's local transmission proposal will do little to satisfy the legitimate desire of backbone level customers to stop paying substantial sums for services that they do not use.

The fourth reason why CCC/Calpine believe that PG&E's proposal should be rejected is that the proposal violates § 454.4. That code section requires that the rates for gas, which is utilized in cogeneration technology projects, not be higher than the rates established for gas utilized as a fuel by an electric plant in the generation of electricity. PG&E contends that its proposal is similar to the electric generator-class proposal which was approved in SoCalGas' BCAP, and which complied with § 454.4. CCC/Calpine contend that the size-based rate design in SoCalGas BCAP was approved because it was functionally identical to a segmented rate design approach that was based on service level. CCC/Calpine contend that unless PG&E can demonstrate that the size-based tiers act as a proxy for level of service, PG&E's proposal would violate § 454.4.

Another reason why CCC/Calpine believe that PG&E's proposal should be rejected is that the rate design is based on arbitrary size classifications, which is in violation of § 453(a). With the possible exception of customers within Tier 4, who use 125 million therms or more per year, PG&E has not offered an explanation as to why it proposes to segment tiers 1 through 3.

Due to the arbitrary size classifications, CCC/Calpine assert that PG&E's proposal would subject customers to undue discrimination in violation of § 453(a). Discrimination would result because customers who do not use local transmission service will be subsidizing customers who use local transmission service, and smaller customers with lower costs-of-service will be subsidizing larger customers with higher costs-of-service.

CCC/Calpine point out that PG&E has demonstrated the arbitrary nature of its own four-tier proposal by suggesting in its briefs, that it would be appropriate to collapse Tier 2 and Tier 3 into one tier, and change the 4 tier proposal into a 3 tier proposal. Such a suggestion implies that PG&E's size-based rate theory is erroneous because customers in tiers 2 and 3, despite their differences in size, would be assessed the same rate.

The fifth reason why PG&E's proposal should be rejected is that it is an inappropriate attempt to appease the proponents of a backbone level rate with a moderate rate decrease, while imposing an arbitrary size-based tier system that will only foster more contentious Commission proceedings. The sole purpose of PG&E's proposal is to discourage certain customers from seeking implementation of a backbone level rate. However, PG&E's proposal fails to align rates with cost-of-service because backbone level customers would still be charged for local transmission services.

TURN also stated that it is not good policy for PG&E to try to appease certain customers with the promise of a discount. TURN warns that such a strategy will only cause the large noncore customers, who threaten to bypass, to push again for a backbone level rate at the next available opportunity.

CCC / Calpine contend that the few parties who support PG&E's four-tier proposal seek to continue the subsidy that they are receiving or seek a second best alternative to backbone level service. NCGC supports the four-tier proposal because the backbone level proposal would unfairly penalize customers who might have located their facilities closer to the backbone if a backbone rate had existed. CCC / Calpine assert that facility-siting decisions are more complex than just considering whether a backbone level rate is available. CCC / Calpine also assert that its backbone level proposal penalizes no one, and remedies an improper cross-subsidy that currently exists in rates.

Duke argues that the four-tier proposal equalizes competition among generators located in PG&E's service area. CCC / Calpine assert that Duke's argument cannot be given weight because a rate design that divides customers into four tiers, and charges different rates based upon the customers' size, will not equalize competition. CCC / Calpine argue that PG&E's four-tier proposal unfairly benefits large, low load factor customers, such as Duke, who are located far from the backbone, at the expense of both smaller and backbone level customers.

CCC / Calpine propose the adoption of a backbone level rate structure in which customers connected to PG&E's backbone pay a backbone level rate, and do not have to pay for any of the costs associated with local transmission. CCC / Calpine also propose that the single average rate for noncore local transmission service be retained.

CCC / Calpine assert that its backbone level proposal aligns customers' rates with their cost of service by adhering to the principle that customers should not pay for services that they do not receive, and "to achieve rates which reflect the costs that the customers imposes on the system." (D.96-04-050 at 3.)

CCC / Calpine contend that the backbone level rate structure is needed to avoid bypass of PG&E's backbone service. This bypass situation has arisen because customers can connect directly to interstate pipelines within PG&E's service territory without having to pay PG&E's local transmission charges.

CCC / Calpine contend that the Commission has taken several actions similar to its backbone level proposal. These actions include differentiating the costs of the backbone, distribution, and transmission functions, and establishing different rates for distribution and transmission-level customers in all three utilities' service territories. CCC / Calpine also assert that the Commission endorsed in principle a backbone level rate for PG&E, but that rate was never implemented in light of the settlements reached in the Gas Accord. CCC / Calpine contend that the next logical step for improving cost causation is to implement a backbone level rate design for noncore local transmission service on PG&E's system.

CCC / Calpine point out that in D.92-12-058 (47 CPUC2d at 448), the Commission established different rates for distribution and transmission-level customers. Large transmission-level customers do not have to bear the costs of distribution system that serves much smaller distribution-level users.

CCC/Calpine contend that the Commission's reasoning in D.92-12-058 should be extended to backbone level customers and the local-transmission system.

CCC/Calpine point out that the Commission already allocates costs separately for backbone and local transmission services. PG&E customers also are allowed to purchase backbone level service. The Commission should unbundle the local transmission charges from backbone service.

CCC/Calpine contend that PG&E's single electric generation class proposal in this proceeding is another example of cost allocation and rate design based on level of service. PG&E's single electric generation class proposal distinguishes between transmission and distribution-level a electric generator, which is the same as the backbone level rate structure proposal.

CCC/Calpine assert that its backbone level proposal is supported by Commission precedent. In D.95-12-053, the Commission considered a request from SMUD that is virtually identical to the backbone level proposal in this proceeding. SMUD built its own pipeline to connect to Lines 400 and 401. In PG&E's 1994 BCAP, SMUD asked the Commission to implement an unbundled rate for backbone level noncore industrial and cogeneration customers. In D.95-12-053, the Commission stated that "an unbundled backbone level rate is consistent with our general direction for the gas industry." The Commission then initiated a second phase of the proceeding to consider more fully SMUD's proposal to create a backbone transmission rate. (63 CPUC2d at 451, 461.) The second phase never materialized as SMUD's desire for a backbone level rate was resolved as part of the Gas Accord. (73 CPUC2d at 838.)

In the Gas Accord, SMUD received a discount of about 94% of the PG&E local transmission charge ($0.0123 per Dth out of $0.131 per Dth.) CCC/Calpine contend that the Gas Accord essentially recognized the legitimacy of a backbone level rate for customers like SMUD, who received a highly discounted rate.

CCC / Calpine also assert that the backbone level proposal is supported by Resolution G-3338 (Feb. 27, 2003). In that situation, a gas distribution-level customer, Praxair, asked SoCalGas for permission to tap into the local transmission system because it would result in a lower rate and cost savings to the customer. In the resolution, the Commission decided that if Praxair wanted transmission-level service, it would be allowed to do so and should be reclassified accordingly. The Commission also expressed concern about the impact of the switch, and whether it would impose stranded costs on the remaining distribution-level customers. SoCalGas was ordered to file an advice letter for similar requests, along with an estimate of the amount of stranded costs associated with each customer's request. The resolution stated that such customers "will be expected to pay for the actual stranded costs that result from such transfers." (Resolution G-3338 at 7, 12.)

CCC / Calpine contend that it may be appropriate, depending on the circumstances, for customers who leave the local transmission system to connect to the backbone, to pay for the stranded local transmission costs they might create. However, under the Praxair reasoning, customers who never used local transmission facilities, but merely opted at the beginning to build their own connection to the backbone system, should not have to pay for any stranded costs because they were not responsible for the incurrence of such costs. TURN's witness acknowledged that this should be the result in that kind of situation.

Duke and PG&E argue that a backbone level proposal will unfairly affect competition in the electricity markets. CCC / Calpine contend that because its proposal is grounded firmly on cost of service principles, and because it eliminates cross subsidies, the backbone level proposal is not unfair at all.

CCC/Calpine point out that Duke prefers PG&E's four-tier proposal out of its own self-interest. PG&E's proposal would continue the subsidization of Duke by Calpine and other backbone level customers, and create new subsidies of Duke by smaller electricity generators and cogenerators.

CCC/Calpine contend that its backbone level proposal complies with the requirement in § 454.4 that electric generators and cogenerators have rate parity. CCC/Calpine assert that the backbone level proposal, which segments rates by service level, complies with § 454.4.

In response to concerns that the backbone level rate might result in cogenerators seeking an equivalent rate, CCC/Calpine state its proposal would not entitle cogenerators connected at the local transmission-level to claim a backbone level rate under § 454.4 because the proposal validly distinguishes between rates for different levels of service. The Commission has construed § 454.4 to allow for parity based on the specific service being provided. For example, under the Gas Accord cogenerators taking firm service receive parity with other electricity generators taking firm service, while cogenerators taking interruptible service receive parity with other electric generators taking interruptible service. (*See* 73 CPUC2d at 823-824.) Similar action was taken in D.00-04-060, where SoCalGas and SDG&E were allowed to charge rates for cogenerators and other electricity generators connected at the distribution-level that differ from the rates charged to those that connect at the transmission-level. CCC/Calpine assert that PG&E's concern regarding parity under § 454.4 is a red herring and should be rejected.

CCC/Calpine also assert that the backbone level rate proposal complies with § 453(a) because it is not based on arbitrary distinctions among customers. Instead, its proposal is based on the services that customers receive and which reflect their cost of service.

CCC/Calpine contend that another advantage of the backbone level proposal is that it will improve reliability for local transmission customers in at least two ways. First, the implementation of a backbone level rate is likely to result in at least some customers shifting from local transmission service to backbone level service. Also, new customers that have the option to connect to either local transmission service or backbone level service will likely choose backbone level service. CCC/Calpine contend that this will result in more capacity being available on the local transmission system. This extra capacity can then be used to serve load growth in that area.

CCC/Calpine contend that the backbone level proposal also strengthens reliability because customers constructing and maintaining their own laterals will enable PG&E to defer having to expand or reinforce its local transmission system, thus avoiding significant reinforcement related expenses.

Duke contends that under a backbone level rate structure, two power plants or two manufacturing facilities, with similar load characteristics, load volumes and service pressures, would pay vastly different rates if one were connected to the backbone, and the other was not. CCC/Calpine point out that customers, such as Duke, will pay higher rates because they are more expensive to serve than customers connected to the backbone. The backbone level rate will also remedy the competitive inequity that a customer such as Calpine faces, *i.e.*, having to pay for local transmission service that it does not use.

Duke argues that a backbone level rate will unfairly tilt the competitive playing to favor generation projects which are located near the pipelines that are currently designated as backbone, regardless of any plant efficiencies or prudent commodity fuel cost purchases. Other noncore gas customers would experience the same competitive imbalance. CCC/Calpine contend that the issue is whether two customers who are physically connected to different levels of service, should have to pay the same rate.

Duke questions whether a backbone level rate will lead to the appropriate siting of new power plants. CCC/Calpine contend that the backbone level rate allows customers to better tailor plant sites to their needs by providing a rate that tracks the true cost of siting near the backbone system. Also, CCC/Calpine assert that the appropriateness of a backbone-only rate, and the creating incentives to site power plants near load centers are two separate and distinct issues.

One of PG&E's arguments against the backbone level rate proposal is its doomsday scenario in which 600 MDth/d of load departs the local transmission system for backbone level service, resulting in a massive shift of costs onto those remaining local transmission customers. CCC/Calpine assert that PG&E's estimate is unlikely to occur because of the location of these customers, and the need to built laterals to connect them to the backbone. At most, 199 MDth/d of load might migrate to backbone level service.

Even if the Commission were to pay attention to PG&E's forecast of migration, CCC/Calpine assert that PG&E overlooks the mechanisms that could mitigate these impacts, such as an exit fee similar to what was discussed in the Praxair resolution, or PG&E can selectively discount local transmission rates.

CCC / Calpine contend that a decision on the backbone level rate is long overdue, and should not be deferred again.

2. Coalinga

Coalinga is the second largest wholesale customer on PG&E's system. Coalinga owns and operates a municipal gas distribution utility and provides natural gas service to residential and small business customers within its boundaries. Coalinga's annual gas requirement is about 2.2 million therms per year (220 MDth), 100% of which is classified as core. As a wholesale customer, Coalinga is both a purchaser and reseller of natural gas. The cost of transporting gas over PG&E's gas transmission system is an important component of Coalinga's cost of service.

Coalinga points out that under the Gas Accord settlement, Coalinga and PG&E's other wholesale customers have paid the same average local transmission rate as all other noncore customers. This rate is presently $0.149 per Dth and reflects an escalated revenue requirement of $153.9 million. This rate is consistent with the Commission's policy that wholesale customers are noncore customers with core load responsibilities. Although Coalinga was not a signatory to the Gas Accord settlement, Coalinga views the settlement as consistent with this policy, and such a policy should be retained beyond 2003. PG&E's proposal to change the wholesale rate would require Coalinga to pay the same local transmission rate as retail core customers is a radical departure from this policy.

Under PG&E's proposal, the revenues allocated to retail core and wholesale core loads would be combined and divided by the sum of their combined throughput to establish a single local transmission rate of $0.419 per Dth. PG&E proposes to charge this rate to both retail core customers and the core loads of its wholesale customers. As a result, Coalinga's local transmission rate would increase by over 180%. Coalinga agrees with Palo Alto, that this disproportionate increase is contrary to the Commission's well-established practice that regulators should pursue stability and consistency in setting rates and avoid rate shock. PG&E's witness concedes that under PG&E's proposed methodology, the rate impacts on core and noncore customers are more dramatic than if the Gas Accord methodology were used to compute local transmission rates.

Coalinga opposes PG&E's proposal, and supports the position taken by Palo Alto. Coalinga points out that the issue of charging wholesale customers the same rates as retail core customers was not identified in the February 26, 2002 scoping memo as an issue, nor was it included as an issue in any subsequent ruling. In addition, PG&E's proposal would violate the Commission's policy that wholesale customers are members of the noncore class with core load responsibilities. Coalinga contends that PG&E's proposal to charge wholesale core loads at a retail core rate violates this policy. Also, the proposed increase in the wholesale rate exceeds what is reasonable, and what is being proposed for other customer classes.

Coalinga points out that wholesale customers on SoCalGas' system do not pay core rates. Coalinga requests the Commission to take official notice of SoCalGas' 2000 BCAP decision, D.00-04-060. In that decision, the rates of SoCalGas' wholesale customers, SDG&E and the City of Long Beach, were set forth in the noncore transportation rates, and were not included as part of the total core revenue requirement.

If the Commission determines that it is necessary to update the local transmission revenue requirement or to modify the rate structure for 2004, it should direct PG&E to use the Gas Accord methodology and charge wholesale customers the local transmission rate that is applicable to other members of the noncore class.

3. Duke

The primary purpose of the participation of Duke Energy North America and Duke Energy Trading and Marketing, collectively "Duke," in this proceeding was to contest the proposal of CCC / Calpine and Mirant for a backbone level gas transportation rate. Duke supports PG&E's proposal for a four-tier local transmission rate for noncore customers and for an improved reliability standard for noncore customers.

a. Backbone level Rate Structure

CCC / Calpine propose that the Commission approve a new, backbone level transportation rate that would be available to customers who are able to connect directly to the pipelines that make up PG&E's backbone system. Under the proposal, a select group of customers would no longer be required to pay for any portion of PG&E's local transmission system.

Duke contends that the backbone level rate is anticompetitive and favors Calpine, Mirant, and some of CCC's members. Under the proposal, the transportation costs for these customers would be reduced by 14.9 cents / Dth, while their direct competitors' costs would be increased by 2.4 cents / Dth to 17.3 cents / Dth. If a lower system load factor than the one CCC / Calpine propose is adopted, the 17.3 cents / Dth advantage would grow even larger. This differential provides CCC / Calpine with a competitive advantage because it lowers their cost of electric generation, which will have an effect on competition in the electricity market. The Commission recognized this when Calpine presented its backbone level proposal before. The Commission stated: "The relief requested [the backbone level rate] would provide more favorable treatment to specific merchant power plants that would obtain a distinct competitive advantage over other merchant generators in California by avoiding payment of local transmission charges which all other on-system merchant generators pay." (D.01-05-086 at 18.)

Duke is impacted by the CCC/Calpine proposal because Duke's gas-fired plants in PG&E's service territory are located on the coast, far away from PG&E's backbone system. If the backbone level rate is adopted, Duke would have no cost-effective way of constructing a pipeline to connect directly to PG&E's backbone system. Based on Duke's estimated 2002 gas usage at its Moss Landing and Morro Bay power plants, Duke would pay $13 million per year in local transmission rates if the backbone level rate is adopted, while Calpine and others would pay nothing for local transmission.

Duke asserts that the proponents of the backbone level proposal gain in two ways. First, the proponents would receive lower rates under the proposal, and second, the proposal would raise the costs of their direct competitors.

CCC/Calpine suggest that the backbone level rate is not unfair. Duke and others note that apart from the obvious economic effects of the proposal, this sudden shift in the regulatory ground rules has the effect of punishing those companies who, like Duke, have invested hundreds of millions of dollars to improve the energy infrastructure in California. Also, the Commission has acted to eliminate rate structures that require some California generators to pay much higher rates for gas transmission than others, solely due to their location. (*See* D.00-04-060.) The Commission stated in D.00-04-060 that competition among electric generators should be based on the efficiency of generating units and the shrewdness of their owners in the gas procurement and financial markets, not on the happenstance of where their plants are located. (D.00-04-060, p. 142.)

CCC / Calpine contend that the backbone level proposal furthers the principle that customers should not pay for services that they do not receive. Duke asserts that this is an oversimplification. Instead of focusing in on the needs of CCC / Calpine only, the Commission must balance the interests of the diverse group of entities that form the general body of ratepayers to arrive at a result that is in the overall public interest. When faced with this constraint, the backbone level rate proposal falls well short of the goal of furthering the overall public interest.

Duke points out that customers in one part of PG&E's system do not make use of other, distant portions of the system. However, due to the Commission's policy of maintaining uniform, geographically averaged rates for the same customer class and schedule throughout PG&E's system, many (if not most) customers pay for parts of the system they do not use.

As for CCC / Calpine's assertion that rates should be based on cost of service, Duke says that cost of service is just one of the factors that Commission typically considers when it sets rates. Dukes asserts that the Commission's primary goal is to further the actions and policies that it determines are in the public interest. If one pursued cost-based rates to the extreme, this would require individualized rates for each customer, a practical impossibility. Also, the pursuit of cost-based rates would conflict with the broader and more important goal of pursuing the public interest.

Duke asserts that the Commission tries to operate in the middle of two extremes, a separate tariff schedule for all customers, or a single tariff schedule for all customers. That is, the Commission group similarly situated customers into customer classes and then develops a handful of tariff schedules for the customers within a class. Rates are generally set to correspond to the costs of customers falling within a particular schedule, but the Commission is neither a slave to cost-based rates nor is it troubled when some customers are required to pay for services that they do not use. Thus, there are so-called "cross-subsidies" inherent in the Commission's ratemaking policies, such as urban subsidizing rural, long-time customers subsidizing new arrivals, and customers served by fully depreciated facilities subsidizing those who are served by newly constructed facilities. The Commission, however, has determined that rate averaging of this sort is in the public interest.

Duke contends that the Commission has previously determined that competitors should not be advantaged or disadvantaged solely because of the location of their facilities. In D.00-04-060, the Commission created competitive rate parity among electric generators in the service territories of SoCalGas and SDG&E by resolving the mismatch between uniform statewide electric prices and utility-specific gas transportation rates. (D.00-04-060, FOF 32 and 33.) A backbone level rate would recreate the problem that D.00-04-060 corrected. In D.01-05-086, the Commission recognized the competitive problems with a backbone level rate that Calpine sought in that proceeding.

Duke accepts that the newer combined cycle generation plants will typically be more efficient than its older Moss Landing and Morro Bay power plants, and that this higher efficiency will give these newer plants a competitive edge. However, the backbone level rate proposal would manufacture a competitive advantage by regulatory action. Duke contends that the Commission should be consistent with the principles stated in D.00-04-060 and encourage competition based on efficiency and investments to improve efficiency. A rate structure that discourages investments in efficiency and rewards some competitors based solely on their location should not be adopted.

Another reason why Duke recommends that the proposal be rejected is that core customers and the remaining noncore customers will face increased costs and higher rates. Under the backbone level proposal, the core's local transmission rate will increase from the current rate of 28.7 cents/Dth to 38.1 cents/Dth. The noncore local transmission rate would increase by at least 2.4 cents/Dth. Duke asserts that more costs will shift to core customers in later years because electric generators who cannot connect to the backbone will generate less electricity as a result of the competitive disadvantage. As these noncore customers make less of a contribution to the recovery of the costs of the local transmission system, local transmission rates will increase during the next revenue allocation process, and the cycle will repeat itself resulting in a "death spiral." In addition, the noncore customers who can connect to PG&E's backbone, are likely to do so to avoid local transmission charges. This will result in the shifting of local transmission costs to the remaining core and noncore customers.

Duke also warns that if the backbone level proposal is adopted, that noncore customers may decide to relocate to sites adjacent to PG&E's backbone system, or may seek interstate pipeline service. In either event, this will lead to less customers paying local transmission charges, and the death spiral would continue.

Duke contends that the Commission has not clearly articulated a policy in favor of an unbundled backbone level rate. Although CCC/Calpine cite D.95-12-053 as supporting such a rate, Duke asserts that the decision also raised several concerns about a backbone level rate, including concern about "the magnitude of the cost shifting that may result from a separately tariffed backbone rate. (D.95-12-053 [63 CPUC2d 414, 451].) Duke also points out that the Commission has yet to approve a backbone level rate. With conditions in the energy industry still unsettled, Duke contends that this is not the time for the Commission to rearrange significant components of the gas delivery system.

Duke asserts that for the natural gas and electricity industries, the Commission has long maintained a policy that rates should be geographically averaged and uniform for similar customers grouped into customer classes. As stated by the Commission in D.99-11-023, "Rates are set on a uniform basis, by customer class, using average cost throughout the service area. (D.99-11-023 at 24.) The Commission also stated that a uniform, geographically average rate "spreads the cost of differential investments in city and rural areas, creates a larger number of customers to share the costs of repairs from disasters and for disaster prevention," and helps spread the costs of public purpose programs. (D.99-11-023, p. 25.)

If the backbone level rate proposal is adopted, this would create a two-zone system for recovery of the costs of the local transmission system. Those noncore customers who are located close to PG&E's backbone system would not contribute to the costs of the local transmission system, while customers located farther away, who are otherwise identical, would bear the local transmission costs.

Duke points out that if the purpose behind the backbone level rate is to eliminate the subsidies inherent in average rates, the proposal should have been based on a mileage-based rate for the backbone system. Instead, the CCC/Calpine proposal is split into two categories, those located adjacent to the backbone system, and those who are located away from the backbone system.

In the expansion proceeding addressing Line 401, the Commission approved a "postage stamp" rate, *i.e.*, a single rate for all shipments using the expansion, regardless of delivery point. (39 CPUC2d 69, 163, FOF 17.) Some parties challenged the rate because, they argued, it was subsidized by Northern California shippers whose gas does not traverse the length of the expansion. Such an argument is similar to the argument of CCC/Calpine. The Commission rejected the argument, and stated that it wanted to encourage efficiencies of scale and scope, and to promote the economic development of the state as a whole. (40 CPUC2d 497, 504.) Duke asserts that by allocating backbone and local transmission costs to all customers helps to encourage efficiencies of scale and scope, and it promotes the economic development of all of PG&E's service territory, instead of just along the backbone system. The Commission should therefore direct in this proceeding that all noncore customers pay rates that reflect the costs of the local transmission system.

Duke contends that another consequence of the backbone level rate is that duplication of facilities is likely. The customers who connect directly to the backbone with a lateral pipeline have no obligation to serve new load growth adjacent to the lateral or their plant. When load growth occurs near the lateral, PG&E may have to construct a new facility, parallel to the privately owned lateral, to serve that new load because of PG&E's obligation to serve. Duke asserts that this is not an efficient outcome.

Another argument that CCC/Calpine raised is that its proposal is consistent with the Commission's policies on unbundling. Although the Commission has established separate backbone and local transmission rate components, the Commission has never approved any of several proposals for a backbone level rate that have come before the Commission previously.

CCC/Calpine contend that the backbone level rate will help PG&E attract and retain major gas loads and will help reduce backbone rates for all customers. Duke contends that no benefits for other customers will result from the backbone level rate unless the decrease in backbone rates for other customers is enough to offset the rate increase that these customers will face when the backbone level customers shift their costs of the local transmission system onto them. The proponents of the backbone level rate acknowledge that the proposal will increase local transmission rates for other customers by $5 million to $10 million in 2004. The local transmission rates for core customers would increase by 4.4 cents/Dth.

CCC/Calpine contend that a backbone level rate will encourage the siting of generation in Northern California. Duke asserts that a backbone level rate will discourage the siting of any new Northern California electric generation except along PG&E's backbone system. In addition, the anticompetitive effects of the backbone level rate will make it more difficult for existing generators that are not able to connect directly to the backbone system to compete successfully for new power contracts or in the short-term power markets. If the electric generators located further from the backbone are unable to compete successfully in the power markets, existing generators will be less likely to invest in upgrading their plants.

Although the backbone level rate may encourage the siting of new power plants along the backbone, electric ratepayers are likely to end up financing upgrades to the electric transmission system in order to deliver this power to customers. Duke contends that the backbone level rate does nothing to ensure that a new generation plant will be located close to either load centers or existing transmission facilities. As the Commission noted in D.01-05-086: "[I]t is not clear whether providing a lower gas rate for power plants located along the backbone pipeline, at a distance from PG&E's electric load centers, would provide appropriate incentives for siting power plants at other locations better suited to help maintain the reliability of the electric transmission grid."

CCC/Calpine also cite the Praxair resolution in support of its backbone level rate. Duke points out that in Praxair, the Commission merely applied existing tariff provisions, whereas CCC/Calpine seek to overturn existing practices and to radically alter the existing tariffs. Duke asserts that the stranded costs in the resolution were minimal; whereas the stranded costs that would result from a backbone level rate would be very significant. Thus, the Praxair resolution sheds no light on this issue, and the resolution stated it was not to be precedent setting. Duke points out that Praxair was a distribution customer, seeking transmission-level service, not backbone service.

Another argument of CCC/Calpine is that the backbone level rate is consistent with rate design in the electric utility industry because electric utilities offer lower rates for customers who connect at higher voltages. Duke asserts that unlike the transformation losses in the voltage-based rate example, the local transmission costs in the backbone level rate situation, do not disappear. Instead, these costs are shifted to the remaining customers on the local transmission system. The voltage based rate structure also has none of the anticompetitive elements of the backbone level rate, and is not a location-based rate. Duke contends that the voltage based rate example is a poor analogy to the backbone level rate.

CCC/Calpine assert that the backbone level rate complies with § 454.4, citing the discussion of the segmented electric generation rate adopted in D.00-04-060. In that decision, the Commission stated that the adopted segmented rate proposal in the BCAP complied with § 454.4 because it treats all electric generators alike, regardless of their size, location, or present or former ownership. Duke says the same cannot be said of the backbone level proposal, which favors a select group of generators over others, based solely on their locations in relation to the backbone.

Duke also warns that due to the parity provisions in § 454.4, if other cogenerators who are not directly connected to the backbone use that section to claim backbone level rate parity, so as to avoid local transmission charges, the harm from the backbone level proposal to other customers would even be greater than anticipated.

CCC/Calpine argue that the backbone level rate is not arbitrary and complies with § 453(a). Duke points out that § 453(a) concerns rate preferences or discrimination with regard to any corporation or person. CCC/Calpine ignore the more relevant requirements of § 453(c) which forbids unreasonable rate differences "between localities." Duke asserts that the Commission's preference for geographically averaged rates is based, in part, on the requirements of section 453(c). The CCC/Calpine witness recognized that the distance between PG&E's backbone system and Duke's coastal generating plants effectively disqualified Duke from the backbone level rate, and other noncore customers face the same kind of geographical discrimination. Duke asserts that the backbone level rate essentially creates a two-zone noncore transmission rate, with customers located within the zone near the backbone system and connecting to the backbone paying a considerably lower rate for transmission than more distant customers.

CCC/Calpine also assert that the backbone level proposal will help discourage bypass of PG&E's system. Duke states that it is probably true that the select group of existing customers who can connect directly to the backbone will be less likely to leave the PG&E system if CCC/Calpine's proposal is adopted. Duke contends, however, that the anticompetitive aspects of the proposal will encourage relocation resulting in more bypass, or it will put companies out of business. The proposal will also reduce the revenues these customers contribute to the costs of the PG&E backbone and local transmission systems, triggering the death spiral for remaining customers mentioned earlier.

CCC/Calpine contend that the backbone level proposal will reduce the costs of PG&E's local transmission system. Duke asserts that this argument only considers one side of the accounting ledger. This argument is based on the assertion that as customers abandon the local transmission system for backbone level service, they make more capacity available on the local transmission system to serve new growth, with the additional benefit that system upgrades can be deferred until needed. Duke asserts that this argument ignores the effects on those customers who remain and who must now bear the local transmission costs. Thus, any alleged benefits of the backbone level rate must be weighed against the lost revenues from the departure of the backbone level customers.

Duke also notes that making more capacity available on PG&E's local transmission system is just a code word for describing stranded costs. Making more capacity available when it is not needed to serve load (the circumstance that will by definition occur when an existing customer connects to the backbone to take advantage of the favorable rate) means that the remaining system will be underused. Yet the full costs still remain, which will have to be borne by the fewer remaining customers who are not in a position to connect to the backbone.

Duke points out that TURN opposes the backbone level rate, but if it is adopted, TURN suggests that the rate be limited to new or incremental load.

Duke points out that even if this was done, there would still be the imposition of costs on remaining core and noncore customers because the utility would be forced to build redundant facilities. Duke also points out that TURN's proposed limitation overlooks the principle that the Commission adopted for pricing of the PG&E Expansion, that the backbone system would not have been built in anything like its current dimensions without the participation of all customers, and that sometimes greater system benefits require the participation of all customers.

CCC/Calpine assert that the Commission has previously indicated support for the backbone level rate. Duke points out that they gloss over the fact that the Commission failed to adopt the backbone level rate three times in recent years, *i.e.,* in D.95-12-053, D.99-11-023, and D.01-05-086. Even in D.95-12-053, in which CCC/Calpine rely on to support their position, the Commission stated that "There are a number of questions that need to be addressed before adopting a separate backbone level rates…" including the magnitude of the cost shifting that may result from a separately tariffed backbone rate. (63 CPUC2d at 451.) Duke suggests that this decision is hardly the ringing endorsement of the backbone level rate that CCC/Calpine would lead one to believe.

CCC/Calpine also assert that their proposal encourages the economic efficient siting of power plants. Duke contends that such a proposal will only encourage the siting of new electric generation plants near the backbone, without regard for how the plants relate to electric load centers or the electric transmission system. CCC/Calpine acknowledge this by stating the Commission could pursue "a separate mechanism to provide incentives for locating near electricity-load centers." Duke questions why the Commission should adopt one proposal that creates inefficient siting incentives, only to adopt another undefined incentive to counter the effects of the first proposal.

b. Four-Tier Rate Proposal

Duke contends that PG&E's four-tier proposal promotes competitive parity among similarly situated generators while maintaining the current requirement that all noncore customers must contribute to the costs of both the backbone and local transmission systems. Duke asserts that PG&E's proposal has several advantages. First, PG&E's proposal equalizes competition among generators located in PG&E's service area because it does not distinguish on the basis of where the plant is located. Second, PG&E's proposal attempts to respond to the competitive challenge that the interstate pipelines present to PG&E by way of bypass by developing a cost-based rate that reflects the lower costs of serving high-volume customers. Third, PG&E's proposal avoids draining the Commission's resources on considering and rejecting the backbone level rate. And fourth, PG&E's proposal maintains the contribution of large noncore customers to the costs of the local transmission system.

Duke finds it ironic that the proponents of the backbone level rate would benefit from PG&E's four-tier proposal, but oppose it because the backbone level rate would provide them with even greater economic and competitive advantages.

Duke notes that Mirant, one of the proponents of the backbone level rate, finds that the four-tier rate structure is the second best option. Mirant notes that the four-tier rate deters uneconomic bypass. Mirant also appears to agree that the four-tiered rate improves the cost basis for local transmission charges and reduces the potential for stranded costs.

4. LGS

Although LGS does not take a position on the issue of the backbone level transmission rate, LGS is responding to some comments made by Duke regarding the issue of project location.

Duke cited D.00-04-060 for the proposition that competitors should not be advantaged or disadvantaged solely because of the location of their facilities. LGS contends that the decision does not stand for such a broad proposition. Although LGS leaves it to the parties to debate the applicability of D.00-04-060 to the backbone level rate proposal, LGS is concerned that there should be no regulatory proposition in this proceeding which holds that location doesn't matter. LGS asserts that location frequently does matter, and to ignore the importance of location is counter to the normal facts of business life.

LGS is located close to the load center. LGS made substantial financial investments to gain approval of its project, and built it in reliance upon the benefits it believe its location would yield. Any statement, which diminishes the importance of location in this proceeding, could negatively impact LGS in the future. There are also ongoing disputes among various storage providers where such a statement could have an impact. LGS urges the Commission not to make any such broad pronouncements in its decision in this proceeding. If location is of importance to the backbone level issue, LGS requests that the decision clearly state that the decision applies only to the circumstances presented here, and to no other.

5. Mirant

Mirant recommends that the Commission adopt the proposal for a backbone level rate structure that reflects the appropriate assignment of local transmission costs to customers who use local transmission facilities. Such rates would exclude backbone level customers from the charges for PG&E's local transmission and distribution facilities, which they do not use. Mirant asserts that backbone level rates are justified as the next logical step in the Commission's unbundling of gas transmission services and cost of service principles. Since this issue has been thoroughly examined, the Commission should act on the proposal.

Mirant points out that the issue of backbone level rates is not new. It was raised in PG&E's 1994 BCAP proceeding in A.94-11-015 in connection with SMUD's development of several new gas-fired cogeneration projects. SMUD proposed a separate, unbundled rate for noncore industrial and cogeneration customers taking service directly from the backbone system. In D.95-12-053 the Commission statedthat "an unbundled backbone level rate is consistent with our general direction for the gas industry." The Commission deferred the backbone level rate issue, and encouraged parties to address it in the Gas Accord negotiations that were underway. (D.95-12-053 at 61-63.)

SMUD's proposal for a backbone level rate was addressed in the Gas Accord when SMUD was given a 94% discount on PG&E's local transmission charges, pending SMUD's purchase of an undivided interest in PG&E's Lines 300 and 401.

PG&E now delivers substantial volumes of gas to customers that are directly connected to its backbone system or that could easily make such connections. Mirant contends that PG&E's current uniform local transmission rate, which is in theory non-bypassable, actually encourages larger transmission-level customers to find bypass alternatives.

Mirant contends that backbone level rates are consistent with cost causation and cost-of-service ratemaking. As Beach testified, "Customers that take service directly from the backbone system do not use, and should not pay for, PG&E's local transmission or distribution systems." Beach further states that an unbundled backbone level rate structure will send correct price signals to all customers. (Ex. 6, pp. 16-17.)

Beach also mentioned several other benefits of an unbundled backbone level rate. First, PG&E is relieved from having to make costly additions to its local transmission system to serve new load that can more efficiently be served by the customer's interconnection to PG&E's backbone system. Second, PG&E will be able to retain major gas loads that might otherwise relocate or seek interstate pipeline service. Third, the backbone level rate sends correct price signals to customers, especially electric generation customers that are able to interconnect directly to PG&E's backbone system. Fourth, the backbone level rate will provide more reliable and less costly electric service once the artificial barrier of mandatory local transmission charges to backbone level electric generation customers is removed. And fifth, a backbone level rate will provide consistency with traditional voltage-based rate differentials in charges for electric service.

Beach recommends that the backbone level rate structure be designed to include the following three unbundled components: (1) a path-specific backbone rate; (2) a customer access charge; and (3) a customer class charge. These rates would apply to all noncore loads that take service directly from PG&E's backbone system using either existing or new laterals paid for by the customer. The primary change in the rate design is that backbone level customers would no longer be charged for the costs of local transmission service that they do not use.

Beach asserts that the impact of the backbone level rate proposal for core and noncore local transmission service customers will be slight, and reasonable, given the inequity of the current requirement that backbone level customers pay for local transmission service that they do not even use. Customers who do not need or use local transmission service should not be required to pay local transmission rates.

As part of the backbone level rate structure, PG&E's four-tier local transmission rate proposal should be rejected. Beach proposes that the local transmission rate design from the Gas Accord be retained, *i.e.*, distinct core and noncore local transmission rates, but applicable only to customers that actually take local transmission service. To the extent the backbone level rate might encourage uneconomic bypass of PG&E's local transmission plant, the proposal would allow PG&E to offer selective discounting of local transmission rates. The proposal would also authorize balancing account protection for 75% of PG&E's local transmission revenue requirement for 2004. (Ex. 6, pp. 3, 26.)

Mirant contends that the backbone level rate proposal is superior to PG&E's tiered local transmission rate proposal because it relieves backbone level customers from having to pay for local transmission services they neither need nor use. Rate reform is needed to bring PG&E's local transmission and backbone level rates more closely into conformance with cost of service.

Mirant agrees with PG&E that the continuation of the present single-tier local transmission rate is a problem. If the Commission maintains the status quo, Mirant asserts that this would be the worst and most harmful outcome. Any failure to address this problem will encourage the sort of large user bypass that is of concern to PG&E and other parties.

Mirant points out that TURN's opposition to the backbone level rate is the risk of creating stranded costs, and appears willing to allow such bypass for new load that did not require past investments in the local transmission system.

Mirant notes that TURN correctly recognizes that if a new or expanded load needs to be served, there is at least the possibility that the utility will avoid its own costs of new construction by allowing that customer to build its own lateral to the backbone system. TURN would limit the application of a backbone level rate to new loads or incremental loads of existing customers, defining new load to include load that has developed since March 1998, and that has always utilized privately constructed facilities to access the backbone system. Mirant believes that the distinction that TURN draws between new load that did or did not require past investments in the local transmission system has merit, because it gets to the heart of the concern about stranding local transmission plant. However, Mirant is not sure why a distinction should be drawn between new load developed since March 1998 and load predating the Gas Accord. Mirant believes that any backbone level load that never required investments in local transmission plant should not be burdened with having to pay local transmission rates.

Mirant contends that ORA's position that all parties should be responsible for paying PG&E's local transmission charges, regardless of whether they benefit from the service or not, is unreasonable. Mirant contends that rate shifting is inevitable because curing an inequity requires some transfer of cost responsibility from those who were unfairly burdened to those who enjoyed an undeserved privilege. To impose a burden of proving that every group of customers will benefit from every rate design proposal would make any rate structure reform impossible.

Mirant recommends that the backbone level rate structure be adopted. However, if that proposal is not adopted, Mirant favors the PG&E's four-tier local transmission rate proposal over the continuation of the current single-tier local transmission rate.

6. NCGC

PG&E proposes to replace the single average local transmission rate for all noncore customers with a declining four-tier rate based on a customer's annual usage for local transmission service. The proposed rate for PG&E's largest noncore customers (Tier 4), which uses 125 million therms or more per year, would be $0.075 per decatherm. For the next largest customers (Tier 3), which have annual usage of 50 to 124.9 million therms per year, PG&E proposes a rate of $0.150 per decatherm. Although there are only 18 customers in PG&E's proposed Tier 3 and Tier 4, throughput to those customers total over 700 Mdth/d.

The Tier 2 noncore customers would include customers with annual loads of 3 million therms to 49.9 million therms. Tier 1 would include customers with annual loads of less than 3 million therms. The local transmission costs that are not recovered from the Tier 3 and Tier 4 customers, due to the establishment of a reduced rate for those customers, are allocated to the core and to Tier 1 and Tier 2 noncore customers on the basis of the currently adopted marginal demand measure for local transmission cost allocation, cold year coincident peak month.

Some of PG&E's largest noncore customers seek backbone level rates, arguing that they are or could be directly connected to PG&E's backbone transmission facilities. PG&E's four-tier local transmission rate structure is a compromise.

Assuming that 600 Mdth/d of load directly connected to the backbone as a result of the backbone level rate structure, core local transmission rates would increase by 9.9% over the level that would result from adoption of PG&E's four-tier compromise.

NCGC supports PG&E's four-tier rate design proposal. The proposal is a reasonable measure to mitigate the bypass of the local transmission system and as a compromise alternative to establishing a backbone level rate. The adoption of a backbone level rate, rather than PG&E's proposal, would unfairly penalize customers who might have located their facilities closer to the backbone if a backbone level rate had existed. The failure to adopt PG&E's proposal or a backbone level rate would encourage PG&E's largest customers to seek an economic alternative to taking service through PG&E.

7. ORA

ORA points out that PG&E's tiered rate proposal is a volume discount mechanism where customers with the highest volume would experience the highest discount, and those in the tiers with lower volume are likely to experience substantial increases in rates. According to TURN's testimony, PG&E's proposal would result in a 46% increase in core rates and an equally large decrease in high volume noncore rates.

ORA asserts that PG&E has not met its burden of proof that the tiered rate structure is justified. Under PG&E's proposal, core customer rates would be adversely impacted. ORA contends that when there is an element of doubt concerning the utility's proposals, that the doubt must be resolved against the utility, and the utility must overcome the presumption that existing rates are reasonable and lawful. (*See* D.00-02-046 [2 CPUC3d 89, 98-99].) Under § 451, whenever a utility proposes a rate increase, the Commission must make a finding that the proposed rates are "justified and reasonable." ORA contends that the substantial rate increases that would result from PG&E's tiered rate proposal are not justified or reasonable.

8. Palo Alto

Palo Alto is considered a wholesale customer of PG&E. Under the Gas Accord settlement and the extension, Palo Alto and PG&E's other wholesale customers contribute to the local transmission revenue requirement of the noncore class and pay the average local transmission rate for the noncore class. This rate is currently $0.149 per Dth, and reflects an escalated revenue requirement of $153.9 million.

PG&E is proposing to calculate the 2004 local transmission rate for retail core customers and the core portion of wholesale customer loads by creating a core local transmission rate. This rate would apply to all "core" loads in PG&E's service area, regardless of whether the customers are physically connected to PG&E's distribution system or receive service from Palo Alto or other wholesale entities.

PG&E's local transmission rate proposal consists of three simultaneous changes: (1) a large increase in the local transmission revenue requirement based, in part, on the proposed Winter Reliability Standard, which promises larger cost increases in the future; (2) a tiered noncore rate structure intended to mitigate pressure from large customers for a backbone level rate; and (3) a new methodology for establishing the local transmission rate for wholesale customers.

If PG&E's proposal is adopted, PG&E's local transmission revenue requirement would grow to $179.3 million, an increase of $25.4 million over 2003. Under PG&E's proposal, the revenues allocated to retail core and wholesale core loads would be combined and a single local transmission rate of $0.419 per Dth would apply to both retail core customers and to core wholesale customers. This rate would increase Palo Alto's local transmission rate and revenue requirement in 2004 by approximately 182%, which is far greater than what is proposed for any other customer class. In contrast, the revenue reductions under PG&E's tiered rate proposal for tiers 3 and 4 would be 1.9% and 51%, respectively, from 2003 levels.

Palo Alto contends that the Commission should reject PG&E's local transmission proposal on procedural, policy, and technical grounds. Procedurally, the local transmission proposal of PG&E was not identified as an issue in the scoping memo or in any subsequent rulings.[86] On policy grounds, the proposal should be rejected because it violates the Commission's long-standing policy that wholesale customers are part of the noncore class,[87] that wholesale customers contribute to the noncore revenue requirement, and that wholesale rates should be based on the wholesale customers' share of the adopted cost allocation factors, not those based on the allocation factors of retail core customers or a co-mingling of retail core and wholesale core shares. Palo Alto asserts that the Commission has never authorized PG&E to combine the core portion of wholesale loads with PG&E's retail core customers for cost

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[86] The effect of PG&E's local transmission proposal on core wholesale customers was mentioned briefly in Chapter 14 of PG&E's application, where it stated in part that "the core retail local transmission rate will also apply to core wholesale customers because they are provided the same level of reliability." (Ex. 3, p. 14-22.)

[87] According to PG&E's Rule 1, Palo Alto's wholesale load is classified as a noncore customer, and not as a core customer. Palo Alto points out that under PG&E's definition of a core customer, the core customer must be physically connected to the local distribution system. None of Palo Alto's core loads are physically connected to PG&E's local distribution system.

allocation purposes, or to charge wholesale customers retail core transmission rates, and should not do so in this proceeding.[88] As stated in Conclusion of Law 58 in D.86-12-010, "Wholesale customers should be treated as noncore customers with core load responsibilities."[89] (22 CPUC2d 491, 566.) Palo Alto also contends that PG&E's proposal would violate the policy of avoiding rate shock on individual customer classes. PG&E downplayed the rate impact on wholesale customers.

On technical grounds, the proposal should be rejected because it is based on the false assumption that retail core customers are subsidizing the local transmission costs of wholesale customers' core loads,[90] and that the proposal

[88] Palo Alto points out that in PG&E's 1995 BCAP decision, D.95-12-053, and SoCalGas's 2000 BCAP decision, D.00-04-060, the gas transportation rates and revenue requirements for wholesale core customers were not included as part of core rates and revenues. Instead, wholesale core customers' rates and revenues are reflected in noncore rates and revenues. (Ex. 54.)

[89] As a wholesale customer, Palo Alto is required to execute a Natural Gas Service Agreement (NGSA). Core customers do not execute an NGSA. Wholesale customers are also required to have meters, which are capable of measuring flow on a daily basis. PG&E's core customers are not required to have daily metering. PG&E's Core Procurement Department, and core transport groups, must balance to a forecasted usage. Palo Alto and other wholesale customers do not have to balance to forecasted usage.

[90] Palo Alto asserts that PG&E's subsidy argument is wrong. As PG&E acknowledged, in the Gas Accord and continuing in 2003, wholesale customers have paid the local transmission rate for the noncore class and contributed to the revenue requirement for the noncore class. (Ex. 3, p. 14-22; Ex. 4, p. 14-14; RT 1114-1115.) In order for retail core customers to have subsidized wholesale customers, revenue would have to shift from Palo Alto and Coalinga, the only wholesale customers when the Gas Accord was adopted. Exhibits 54 and 55 clearly demonstrate that there was no shifting of local transmission revenue from wholesale or other noncore customers to retail core customers.

disregards the major differences between the cost drivers of retail core customers and wholesale customers.[91] Palo Alto contends that lumping retail core and wholesale customers together would disregard the huge differences in costs between core customers and wholesale customers.

9. Sacramento Municipal Utility District

SMUD is constructing a new natural gas-fired combined cycle power plant, the first phase of which will generate 500 MW and is scheduled to go on-line in 2005. The second phase of the project will generate another 500 MW, and is scheduled to go on-line in 2008. The first phase will approximately double SMUD's existing gas load of 60,000 decatherms per day (Dth/d), and the second phase will triple SMUD's existing gas load.

SMUD has a 51 mile, 20 inch high-pressure pipeline, which connects its plants to PG&E's backbone system. SMUD plans to extend its pipeline by an additional 26 miles to connect to its new plant. SMUD points out that the pipeline was constructed at its own customers' expense, and PG&E or its ratepayers paid none of the costs for.

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[91] Palo Alto points out that there are major cost differences between retail core customers and wholesale customers. The average throughput per wholesale customer is much greater than the average retail core throughput per customer. In addition, many of PG&E's retail core customers are connected to distribution feeder mains (DFMs), which are part of PG&E's local transmission system. Local transmission pipelines that are connected to PG&E's backbone transmission system serve wholesale customers, such as Palo Alto, and no DFMs are required to serve them. (Ex. 1, pp. 2-5; 7 RT 763.) Palo Alto also receives gas at a much higher pressure than retail core customers. Also, the balancing requirements for noncore customers, including wholesale customers, is much stricter than the balancing requirement for core procurement.

SMUD proposes three changes to PG&E's proposed Gas Accord rate structure. SMUD's first proposal is that the Commission establishes an unbundled backbone level rate structure for gas customers who take service directly from PG&E's backbone transmission system. The second proposal is that the Commission either (1) adopt a load factor based on the volume of capacity sold, rather than adopting PG&E's proposed load factor reduction based on projected throughput, or (2) direct PG&E to sell surplus backbone capacity to SMUD. SMUD's third proposal is if the Commission does not adopt the two proposals, that the Commission amend PG&E's proposed Rule 27 to allow SMUD to receive a credit against the local transmission rates for the cost savings that PG&E customers enjoyed by having SMUD build its own pipeline system to serve its new gas-fired plants rather than having PG&E upgrade its existing local transmission system.

SMUD asserts that a backbone rate would send correct price signals to new electric generators, improve the reliability of PG&E's local transmission system, and reduce the need for PG&E to expand its own local transmission system, thus reducing costs for other ratepayers.

SMUD first raised the backbone rate issue in PG&E's 1994 BCAP proceeding, A.94-11-015. At the time, and before SMUD's pipeline was built, SMUD argued that it should not have to pay for transportation charges to move gas across its own pipeline. In D.95-12-053 at 61, the Commission found that "an unbundled backbone level rate is consistent with our general direction for the gas industry." D.95-12-053 then opened a second phase of the BCAP to consider the issues associated with implementing a backbone level rate. SMUD and PG&E then negotiated the sale to SMUD of an undivided interest in PG&E's backbone Lines 300 and 401. The Gas Accord provided that if the sale was not approved before the Gas Accord became effective, that SMUD should receive a discount of about 95% of the PG&E local transmission charge. (73 CPUC2d at 818.) The Gas Accord essentially provided SMUD with a backbone level rate. The sale to SMUD of the interest in Lines 300 and 401 was approved by the Commission in D.97-04-087. The Commission found in D.97-04-087 that such a sale would provide incremental throughput for the PG&E backbone system and would avoid the stranding of backbone capacity that would occur if SMUD took backbone service on another pipeline. The Commission also found that SMUD would be able to stabilize its long-term costs of transportation and optimize use of its own pipeline facilities, which SMUD constructed at its own expense, saving PG&E millions of dollars in construction costs it otherwise would have incurred. The Commission also found that the lateral to the backbone that SMUD built did not represent bypass of the PG&E's local transmission system, because the PG&E system could not meet SMUD's requirements without substantial expansions.

SMUD points out that TURN supported SMUD's backbone equity purchase. TURN also acknowledges that if the Commission adopts a backbone level rate structure, it should limit the application of such a policy to new loads or incremental loads of existing customers. Since TURN defines new load to include load that has developed since the start of the Gas Accord period, and which utilizes privately-constructed facilities to access the backbone system, SMUD requests that the Commission define new load to expressly include SMUD's local transmission pipeline system, which was built before the Gas Accord was negotiated.

SMUD's equity capacity in the two lines exceeds SMUD's average daily load, but is below its peak load of 100,000 Dth/d. To the extent SMUD's gas moves through its equity capacity, SMUD does not have to pay for local transport charges across its own local pipeline. However, during high load periods, SMUD has to pay for local transport charges. Once SMUD's new plant comes on-line in 2005, SMUD will be required to pay these local transmission charges on a regular basis, unless the Commission changes the rate structure.

PG&E's argument against a backbone level rate is that the core and noncore customers who are not directly connected to backbone facilities will pay a larger share of the local transmission costs. SMUD asserts that PG&E's argument is contrary to cost-of-service principles. Customers who take service directly from the backbone system do not use, and should not have to pay for PG&E's local transmission or distribution systems.

SMUD points out that PG&E's prepared testimony describes a local transmission customer as "situated anywhere from 5 feet to 150 miles from PG&E's backbone facilities." (Ex. 1, p. 14-21.) Since SMUD's pipeline facilities are connected directly to PG&E's backbone, SMUD does not fit within that definition because it is located zero feet from the backbone. SMUD argues that if the Commission does not adopt a backbone level rate, under PG&E's definition, SMUD should not be considered a local transmission customer and should not have to pay local transmission charges. SMUD contends that the only charges that should be collected from SMUD are the customer access charge expenses to administer SMUD's account.

SMUD contends that the most important beneficiaries of a backbone level rate would be the 1.3 million people served by SMUD in a service territory of 900 square miles in the greater Sacramento area. If PG&E's rate structure remains the same, SMUD's customers would be charged for services that they do not use.

Customers that take service directly from the backbone system do not use, and should not have to pay for, PG&E's local transmission or distribution systems.

10. TURN

a. Backbone level Rate Structure

TURN recommends that the Commission reject the proposal of CCC / Calpine for a backbone level rate, or at a maximum, allow bypass only for new load that did not require past investments by PG&E in the local transmission system.

CCC / Calpine propose that the Commission establish a backbone level rate for customers who connect directly to PG&E's backbone. They argue that such a proposal is justified and consistent with cost-causation principles because backbone customers do not create costs on the local transmission system.

Currently, about 19 customers are connected to PG&E's backbone. Approximately four of these customers have connected to the backbone since the start of the Gas Accord.

TURN points out that the cost-causation argument of CCC / Calpine only applies to the incremental load, which has never taken service from the local transmission system. A customer who currently takes service from the local transmission system and bypasses this system only in order to take advantage of a backbone level rate has already contributed to the fixed costs of the local transmission system, since the system was designed to provide full service to all existing customers. If a customer bypasses the local transmission system, the rates of all remaining customers (core and noncore) would have to increase to make up for the lost local transmission revenues. When the throughput forecast is adjusted in the next BCAP proceeding, the rates of core customers would increase due to reduced noncore throughput. TURN estimates that the annual revenue loss associated with the bypass of local transmission could be as high as $32.5 million.

TURN contends that allowing customers who are currently served from the local transmission system to build laterals to bypass the local transmission system is unnecessary and may impose significant costs onto the remaining ratepayers. Those existing customers' needs are adequately served from the local transmission system interconnects.

The CCC / Calpine witness concluded that a backbone level rate would increase core rates less than PG&E's tiered rate proposal for local transmission. TURN points out, however, that the analysis of CCC / Calpine assumes that no customers, who are currently connected to the local transmission system, will choose to build a lateral to the backbone. The analysis by the CCC / Calpine witness assumed that only the load connected to the backbone will qualify for the backbone level rate, which results in a CCC / Calpine forecast of backbone load which is about one-fourth that of PG&E's forecast. TURN contends that if a backbone level rate is adopted, the potential customers and associated load, and the resulting cost shift, is likely to be much greater than what CCC / Calpine assumed.

TURN asserts that before a backbone level rate is adopted, the Commission must consider the unbundling that has already taken place, before it decides if there should be further unbundling of the system. TURN asserts that it is not clear that California will be better off if it replaces the integrated gas utility system with a series of privately-owned laterals to serve specific customers. Serious issues of facility duplication and economic waste are raised by such a policy. In addition, the siting of future power plants may be done on the basis of proximity to a backbone pipeline, rather than to a load center.

In the event the Commission adopts a backbone level rate, TURN recommends that it only apply to new loads or the incremental loads of existing customers. Customers, who have taken service from the local transmission system historically, should not be eligible for any backbone level rate. This will avoid the problem of an existing local transmission customer selecting the backbone rate in order to obtain a lower rate, which will then result in stranded costs being shifted to the remaining ratepayers.

If the Commission chooses to adopt a backbone-rate for all customers with a corresponding charge for "stranded costs," TURN recommends that a separate phase of this proceeding be implemented to address the stranded cost calculation.

TURN does not agree with the argument of CCC/Calpine that the reasoning in the Praxair resolution supports their contention that customers with existing connections to the local transmission system should be allowed to bypass. The Praxair situation found that the potential cost shift was not large. This is in contrast to a potential cost shift of over $30 million if 12 out of the 18 largest noncore customers of PG&E choose to bypass the local transmission system.

b. Four-Tier Rate Proposal

PG&E proposes to increase the total annual local transmission revenue requirement from $153.89 million (2003) to $179.263 million (2004), an increase of $25.373 million. (Ex. 76.) Part of the increase is due to the costs of local transmission upgrades associated with the Winter Reliability Standard to provide the noncore with an increased reliability standard. However, PG&E's

cost allocation proposal also assigns more of the increase in the local transmission revenue requirement to core customers. Under PG&E's cost allocation proposal, the core's portion of the local transmission revenue requirement would increase by $36.201 million (from $87.242 million in 2003 to $123.443 million in 2004), while the noncore would enjoy a $10.828 million reduction (from $66.648 million in 2003 to $55.820 million in 2004) in its allocation of the local transmission revenue requirement. TURN notes that although noncore rates decrease, a portion of the increase is due to the costs of local transmission upgrades that are necessary to provide the noncore with increased reliability under the Winter Reliability Standard.

TURN contends that PG&E's rate proposal violates Commission precedent and policies, is contrary to generally accepted methods of cost allocation and rate design, and violates PG&E's prior representations before the Commission. PG&E's methodology did not follow generally accepted methods of cost allocation and rate design because the total local transmission revenue requirement of $179.263 million was not allocated properly among the customer classes using the appropriate allocation factor. According to TURN, the costs should have been allocated to the core and noncore customers before rates were determined.

TURN asserts that the rates for tier 3 and tier 4 customers were arbitrarily set. PG&E did not use cost of service, value of service, long-run marginal costs, short-run marginal costs, embedded costs or incremental costs to calculate the revenue requirement for tiers 3 and 4. As a result, PG&E's proposal will cause a 40.5% increase in the core's revenue requirement allocation. Wholesale customers, such as Palo Alto, will experience a 181.4% increase in the local transmission revenue requirement allocation.

Currently, retail core customers pay $.287 per Dth for local transmission, about 1.97 times the $0.149 per Dth that noncore retail customers pay. Under PG&E's proposal, the core rate would increase by 46% to $0.419 per Dth, while the average noncore rate would drop to $0.128 per Dth. Thus, the new core rate would be approximately 3.8 times more than the average new noncore rate.

If PG&E were to extend the existing Gas Accord cost allocation methodology into 2004, the core's portion of the local transmission revenue requirement would be $114.538 million with core wholesale, or $112.969 million without core wholesale. The noncore's portion would be $66.294 million with core wholesale or $64.725 million without core wholesale. The core would pay $0.389 per Dth, and the noncore would remain unchanged at $0.149 per Dth. Although this represents a rate increase of 35.6% for the core, TURN contends that such a result would be preferable to PG&E's proposal.

PG&E's rationale for its proposed cost allocation is to discourage large noncore customers, who are located near PG&E's backbone facilities, from seeking a backbone level rate. However, TURN contends that these savings in local transmission rates for tiers 3 and 4 will allow these customers to use the savings to construct facilities to tap into PG&E's backbone system, and to further advocate for a backbone level rate. TURN asserts that PG&E's proposal creates a subsidy for PG&E's wealthiest customers, and shifts a considerable burden onto core customers in a futile effort to prevent large customers from seeking a backbone level rate.

PG&E has offered an economies of scale argument in support of its four-tier local transmission rate proposal. TURN points out, however, that the economies of scale argument did not serve as the basis for PG&E's proposed local transmission cost allocation. Instead the proposed allocation resulted from “hard-wiring” the cost allocations to noncore tier 3 and tier 4 at arbitrary levels. After that, PG&E apportions revenue responsibilities between noncore tiers 1 and 2, and the core, according to its marginal demand measure. TURN asserts that this is an improper and unprecedented method of arriving at rates.

TURN contends that the use of an allocation factor is the proper tool to allocate costs between the customer classes. Once the utility has set a revenue requirement ($179.263 million) for a function, the next step is to multiply the allocation factor assigned to each customer class by the total revenue requirement. The products of these calculations are the respective responsibilities for the revenue requirement of each customer class, upon which rates are based. Such a process allows the utility to compete more effectively for noncore customers, and it also protects the core from the utility forcing it to bear any revenue shortfalls that result from the utility’s contracts with noncore customers. PG&E’s proposed local transmission cost allocation directly contradicts this, and improperly attempts to protect revenues by forcing the core to pay rates that reflect revenue that it may not get from those geographically well-situated noncore customers in tiers 3 and 4.

TURN also argues that PG&E’s application violates § 739.7 because it will increase the core’s baseline rates for the explicit purpose of subsidizing a handful of wealthy noncore customers in tiers 3 and 4, with no corresponding decrease in core non-baseline rates.

TURN suggests that if a higher standard of reliability for noncore service is adopted, the Commission should consider moving from a cold-year peak month allocater to a cold-year non-coincident peak month measure. TURN contends that such a methodology would better capture the impact on the system of those noncore customers whose maximum usage occurs in a month other than January.

PG&E has marketed its four-tier local transmission proposal as constituting the lesser of two evils, *i.e.*, a backbone level rate versus PG&E's cost allocation and rate design. TURN points out that the third alternative is to simply maintain the existing Gas Accord structure and cost allocation methodology. A fourth alternative is to create tiered rates within the noncore customer class and to maintain the Gas Accord cost allocation between noncore and core.

11. PG&E

PG&E recommends that the Commission adopt PG&E's four-tier declining local transmission rate proposal, and that the proposal of CCC/Calpine and SMUD for a backbone level rate structure be rejected. The backbone level rate structure issue involves the interests of some generators who are located near PG&E's backbone transmission facilities, which needs to be balanced with the interests of 3.8 million core and noncore customers. PG&E contends that the 3.8 million customers will not benefit from the backbone level rate structure proposal, and would end up paying higher rates. PG&E recommends that the Commission adhere to its long-standing policy of non-bypassable local transmission charges for all customers.

PG&E asserts that its four-tier noncore local transmission rate proposal offers a rate compromise to large or well-situated generators and customers such as Calpine, CCC, CMTA and Mirant, compared to the single average non-bypassable noncore local transmission rate that exists today. PG&E contends that its proposal moves local transmission rates closer to the cost of service for each specific noncore customer segment, while balancing customer concerns for higher rates that would occur under a backbone level rate structure.

PG&E's proposal recognizes that all customers, including core customers, must bear some of the additional cost responsibility from a rate structure that may mitigate or discourage Tier 3 and Tier 4 customers from seeking a backbone level rate structure. PG&E's proposal offers a compromise between the full averaged noncore rates of today and rates that better reflect the cost of providing the service.

PG&E acknowledges that its local transmission cost allocation and rate proposal results in increases for certain smaller noncore and core customers. However, these increases are not nearly as high as they would be under the backbone level rate structure.

PG&E's studies suggest that 600 MDth/d or more of load potentially qualify for backbone level rate treatment. Under the proposed backbone level rate structure, core and noncore customers who remain on local transmission facilities could pay local transmission rates that are 25 to 61% higher than rates today as shown in Table 14-2 of Exhibit 4. PG&E contends that the impacts of a backbone level rate will grow over time, and cannot be reviewed based solely on current backbone level connections.

The proponents of the backbone level rate fail to take any responsibility for the revenue loss or the underutilization of local transmission facilities that could result. If noncore customers who connect directly to the backbone, are no longer required to pay the local transmission rate, PG&E would receive less revenue from those customers, while the revenue responsibility of other customers would increase.

PG&E notes that PG&E's noncore customers are "a diverse group, ranging from about 785 customers who use less than 3 million therms per year to a small number of large electric generators and refineries that use more than 125 million therms per year." (Ex. 3, p. 1-15.) With the variations in size and demand patterns, the actual cost to serve individual noncore customers varies substantially, and some noncore customers are well situated either to connect directly to PG&E's backbone facilities or to bypass PG&E's system entirely. PG&E's proposed four-tiered rate structure is segmented by annual usage, and reduces local transmission rates for the largest noncore customers while moderately increasing rates for core and small noncore customers.

PG&E states that its studies demonstrate that economies of scale are a primary consideration in examining the costs to serve large Tier 3 and 4 customers. PG&E's studies indicate that the cost to serve 35% of the Tier 4 load is below 7.5 cents per dth. Since Tier 4 customers have loads that are 2.5 to 12 times greater than Tier 3 customers, their rate per unit is significantly lower, reflecting the economies of scale.

PG&E points out that its segmented noncore local transmission rate design is similar to the electric generator rate segmentation that was adopted for SoCalGas, and complies with § 454.4, as interpreted by the Commission in D.00-04-060.

PG&E points out that if the proposal for a backbone level rate for customers who are directly connected to the backbone is adopted, there is the possibility that cogeneration customers might be entitled to the same backbone level rate under the parity rights in § 454.4. If the cogenerators were successful, this would increase the load qualifying for the backbone level rate by an additional 265 MDth / d. If 865 MDth / d (600 MDth / d plus 265 MDth / d) or more of load were to qualify for backbone level rate, local transmission rates will increase substantially for all remaining core and noncore customers. As the rate differential between backbone level rates and backbone plus local transmission rates widen, the incentive increases for additional customers to build connections to the backbone. PG&E's four-tier proposal is reasonable since it moves noncore rate levels closer toward the cost of service, while continuing the Commission's policy of non-bypassable local transmission rates and a revenue responsibility that is shared by all customers.

PG&E asserts that a backbone level rate structure would discriminate against those who have made economic decisions to site facilities away from PG&E's backbone facilities. Since existing customers do not have a choice in their level of service, PG&E contends that it would be discriminatory to set rates based on the geographic location of one facility over another. PG&E also states that such a structure would also encourage large or well-situated gas customers to build gas pipeline laterals to connect to the backbone facilities, which would inefficiently duplicate existing PG&E facilities.

PG&E also points out that rate designs are not based solely on service-level cost causation. Instead, other factors, such as compliance with § 454.4 or core service reliability, can cause customers to pay for facilities that they do not necessarily use. The Commission's policy is to set average cost rates, not exact cost rates.

TURN criticized PG&E's proposed local transmission cost allocation and rate design because PG&E did not offer a sufficient reason to deviate from the established methodology. PG&E points out that its local transmission rate proposal is designed to discourage uneconomic bypass by substantially reducing the economic incentive for those customers who desire a backbone level rate. It moves the local transmission rates closer to the cost of service for each specific noncore customer segment while balancing customer concerns for higher rates that would occur under a backbone level rate structure. PG&E contends that the continued use of the existing local transmission cost allocation and rate design methodology for noncore customers will not remove the incentive for certain large or well-situated customers to seek a backbone level rate alternative. The CCC / Calpine witness agreed that if a backbone level rate is not adopted, and the four-tier rate is adopted, that this would be an improvement for his clients over the local transmission rate levels they pay today.

The cities of Palo Alto and Coalinga pay noncore local transmission rates as part of the Gas Accord Settlement Agreement. PG&E recommends that this treatment not be continued in 2004. Instead, these wholesale customers should pay core local transmission rates on behalf of core customer loads they serve and pay noncore local transmission rates on behalf of the noncore customer loads they serve. PG&E's proposal to charge wholesale core customers the core local transmission rate correctly aligns rates with the level of service reliability that wholesale core customers receive. If PG&E's proposal is not adopted, this will continue the inequitable situation which forces core retail customers to subsidize the local transmission rates paid by core wholesale customers.

PG&E points out that wholesale customers can agree to take service at the lower noncore rate. However, this would reflect service at the noncore's level of reliability. It would also mean that they would not receive the core's abnormal peak day reliability, or the rights to vintage core Redwood capacity.

PG&E contends that its local transmission rate proposal for wholesale customers is consistent with D.86-12-005 because it eliminates the current local transmission cost subsidy paid by core retail customers on behalf of core wholesale customers. PG&E proposes to charge core wholesale customers the core local transmission rate, consistent with the core vintage backbone rates they receive. PG&E proposes to charge noncore wholesale customers the noncore local transmission rate, consistent with the noncore backbone rates they pay.

PG&E opposes the proposal of TURN, ORA and Palo Alto to simply extend the 2003 local transmission rates. Such an extension will not allow PG&E to recover its local transmission cost of service, and does not recognize the differences in cost of service for customers. Although all costs could be recovered for 2004 with a single-tier rate design, PG&E contends that such a design provides an incentive for certain customers to continue to seek a backbone level rate structure, or other transportation alternatives.

Palo Alto's claim that wholesale customers' local transmission rates were not being subsidized during the Gas Accord period is flawed and without merit. PG&E contends that the table in Exhibit 55 demonstrates that the local transmission marginal cost unit rate to serve wholesale customers is higher than the local transmission marginal cost unit rate to serve core customers. Also, the wholesale unit rates are more than twice the unit rates to serve noncore retail customers. Since core wholesale customers have been paying the noncore retail local transmission rate during the Gas Accord period, wholesale core customers receive a significant local transmission rate subsidy, compared to their underlying cost of service. The difference between their rate and cost of service is allocated to core retail customers.

PG&E's proposal regarding wholesale customers would result in less than a dollar per month increase to the typical residential customer in Palo Alto's service territory, and approximately a $1.35 per month increase to the typical residential customer in Coalinga's service territory. PG&E contends that the proposed local transmission charge amounts to only a fraction of the burnertip cost of gas for end-use customers.

TURN contends that if a higher standard of reliability for noncore service is adopted, local transmission cost allocation should be done on the basis of a cold year non-coincident peak month measure. PG&E asserts that TURN's contention is without merit because cost allocation based on a cold year coincident peak month already represents a less extreme demand measure than strict cost causation principles such as cold winter day or abnormal peak day, and allocates costs in an equitable manner to core and noncore customers. PG&E asserts that the cold year coincident peak month continues to be the appropriate marginal demand measure for local transmission cost allocation between core and noncore customers.

a. Discussion

Local transmission facilities consist of non-backbone facilities with design operating pressures greater than 60 pounds per square inch gauge. Under the current Gas Accord structure, all on-system end-use customers are obligated to pay local transmission rates.

The backbone level rate structure is discussed in this section because the proposal, if adopted, would eliminate the responsibility of customers who are directly connected to PG&E's backbone from having to pay local transmission charges. Gas consumers located near interstate pipelines have sought to connect to those pipelines to avoid having to pay PG&E's local transmission charges. Requests for a backbone level rate have come before the Commission previously. (*See* D.95-12-053 [63 CPUC2d 414]; D.01-05-086.)

To address the potential bypass of PG&E's gas transmission facilities, PG&E proposes that a declining four-tier local transmission rate structure be adopted in 2004 for noncore customers. CCC / Calpine, Mirant, and SMUD propose that the Commission authorize a backbone level rate structure, which permits an end-user to connect directly to PG&E's backbone transmission system, and thus avoid having to pay local transmission charges. Other parties advocate that the current allocation method be used, i.e., a single average rate for noncore, including core wholesale, and a core retail rate. The common thread among the parties who favor or oppose these proposals is whether or not the proposals will be of financial benefit or harm to them.

The purpose behind PG&E's four-tier proposal is to provide a financial incentive for large customers, who are considering a bypass of PG&E's transmission facilities, to remain on the system because of lower local transmission charges. In contrast, the backbone-level rate proposal allows those customers who are located in close proximity to PG&E's backbone to take backbone service, and to avoid any local transmission charges. TURN would limit the application of a backbone-only rate to new loads or incremental loads of existing customers. TURN defines "new load", as load that was developed after March 1998. We support the backbone-level rate proposal, with modifications. As currently delineated, neither PG&E's four-tier local transmission rate structure, nor Calpine's backbone level rate should be adopted. As a result, we direct PG&E to submit a rate design (at the time of their next revenue requirement filing) that represents a backbone level rate to be applied only to new load or incremental load that has been developed since March 1998. In the interim, we leave the current local transmission rate structure in place for 2004.

PG&E asserts that its four-tier non-core local transmission rate proposal offers a rate compromise to large or well-situated generators and customers such as Calpine, CCC, CMTA and Mirant, compared to the single average non-bypassable non-core local transmission rate that exists today. We believe (as CCC / Calpine, TURN, SMUD, and Mirant has asserted) that PG&E's cost analysis contains methodological inconsistencies. Also important, while the four-tier proposal represents PG&E's best effort to protect its interests and those of others, it only would be a temporary mitigation of fundamental concerns that would surely resurface at the next phase of the Gas Accord. As indicated previously, there are legitimate and competing issues regarding who pays for local transmission and what levels of subsidy, if any, may occur. The path towards unbundling has not been and will not be painless. That circumstance should not prohibit us from moving forward with policies that moves us closer to an energy market that is both vibrant and competitive.

That desire, however, does not suggest that we intend to unfairly burden the captive consumer. Similar to TURN, we believe that past investments in PG&Es the local transmission system should be passed on those who directly benefited. We also agree with TURN that if a new or expanded load is to be served then there should be a cost savings to PG&E (and presumably its ratepayers) if a prospective customer builds a lateral to the backbone system. Hence, we agree with TURN that a backbone level rate design should only apply to "new load" developed after March 1998. This date coincides with with the start of the implementation of the first Gas Accord. We believe that an application of this new rate structure to load developed after that time period reflects a more balanced approach to implementing this potentially fundamental shift in policy direction.

As the Gas Accord is currently structured, there are many as well as competing interests that are being considered. On the one hand, it is in PG&E's interest to recover costs associated with their local transmission system. On the other hand, it is in the interest of noncore customers who have an interconnection to the PG&E backbone pipeline, to assert that they should not have to pay local transmission charges. Conversely, it is in the interest of noncore customers whose distance make it impractical to establish an interconnect to PG&E's backbone, to argue that it is inequitable for noncore consumers with a lateral to PG&E's backbone to bypass a local transmission charge.

As suggested by Duke and PG&E, a backbone level rate design presents a multitude of cost allocation, rate design, and market structure issues that requires careful attention by Commission decision-makers. Additionally, most parties agree that there are significant public policy and economic implications associated with bypass of PG&E's transmission system. If a mass exodus were to occur then it is possible that there would be stranded costs to be paid by those who remain on PG&E's system. In view of that, there is a question as to whether or not the Commission should consider this matter now or postpone further deliberation on this issue until a latter date.

In the D.01-05-086, it was decided that the issue of the backbone level rate would be deferred to the Gas Accord II, which began January 1, 2003. We find that there is no sufficient justification to defer consideration of this matter to a time in the distant future. Accordingly, we direct PG&E to develop proposals that utilize the Beach recommendations of a backbone-level rate structure designed to include a path-specific backbone rate; a customer access charge; and a customer class charge[92]. These rates would apply to noncore loads that take service directly from PG&E's backbone system using new laterals (online after March 1998) that are owned and operated by the customer. The rate design of this proposal reflects an effort to not pass on potentially unjust cost shifts to PG&E's customers.

PG&E customers ineligible for the backbone level rate will pay an averaged local transmission rate.

We believe that this proposed framework prevents stranded costs from being passed on to PG&E customers resulting from lost local transmission revenue due to departing customers that own and maintain a lateral to the PG&E backbone system[93]. It is clear that a cost recovery surcharge could not be determined easily without a lengthy and arduous effort on the part of PG&E. It seems that an attempt to develop a cost recovery surcharge and a subsequent balancing account treatment for un-recovered loss revenue would potentially create more problems than it would solve. We believe that adopting a proposed backbone level rate for new load developed after March, 1998 balances the concerns of the large noncore customer with a lateral pipeline to PG&E backbone

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[92] Similar to the proposed decision, local cogenerators connected at the local transmission-level will not be entitled to seek an equivalent backbone only rate plan under § 454.4.

[93] It has been suggested in this proceeding that a potential cost shift of over $30 million would occur if 12 out of the 18 largest noncore customers of PG&E choose to bypass the local transmission system.

system, with PG&E's desire to recover charges for local transmission, and yet leaves the core customer largely indifferent.

It is unreasonable to continue with a status quo of a one size fits all local transmission rate that does not properly reflect existing market conditions. Simply put, the cost impacts to the core and to the noncore (who are unable to build an interconnect to PG&E's backbone) needs to be carefully weighed against the costs to the noncore customer that has built a lateral to the backbone pipeline system.

We acknowledge that cross-subsidies exist, and in many instances, do serve the public good. For example in this instant case, we do not substantively alter the proposed decision's finding regarding the rollover of Line 401 costs to the core. While PG&E and the noncore may strongly oppose this course of action, we find that it is appropriate to maintain the current cost allocation structure as it relates to Line 401. As noted earlier, the CCC and Calpine acknowledge in their reply brief that "as a matter of social policy, the Commission may choose to provide subsidies to one class of customers at the expense of others …" and that it is "difficult to eliminate all subsidies from rates, and that rate averaging will be, to some extent, necessary." In regards to whether PG&E can offer a core transmission rate for wholesale customers of PG&E, we do not agree that the six wholesale customers who serve their own customers should be treated as a core customers for the purpose of local transmission charges. Although they enjoy certain benefits of being a core customer, as Coalinga and Palo Alto point out, they also have attributes, which clearly distinguish them as noncore. As noted in Conclusion of Law 58 in D.86-12-009, "Wholesale customers should be treated as noncore customers with core load responsibilities." (D.86-12-010 [22 CPUC2d at 566]; *See* D.86-12-009 [22 CPUC2d

444, 478-479].) There is no compelling reason to consider treating wholesale customers differently after more than 15 years.

To develop PG&E's 2004 volumetric local transmission rates, PG&E shall use the existing cost allocation and rate design methodology from the Gas Accord. Wholesale customers shall be treated as noncore. A single average rate for core, and a single average rate for noncore, shall be used. Local transmission rates (by 2005) shall be amended to reflect our policy that noncore customers who after March 1998, constructed an interconnect to PG&E's backbone system will be exempt from paying local transmission charges. This backbone level rate should reflect the Beach recommendations that a rate design should incorporate a customer access charge, size and location. To some extent, those customers ineligible for the backbone level rate will have to pay a local transmission rate that reflects further rate design by PG&E (starting in 2005).

Interested parties have filed written comments on the proposed backbone level rate, with modifications. The comments of the interested parties have been considered and changes where appropriate have been made to this decision. By March 19, 2004 (deadline to submit the revenue requirement for 2005), PG&E is directed to a generate a rate design that reflects the actual cost of service (i.e. location, size, access) for noncore customers who have built a lateral pipeline to PG&Es backbone system after March of 1998. PG&E's proposals will be subject to review and approval by aCommission decision. In the interim, PG&E shall structure its local transmission rate according to currently adopted methodology. PG&E shall file an advice letter in 10 days with an effective date of January 1, 2004, subject to Energy Division review and approval, to implement this interim rate.

E. Other End-User Rate Components

1. Customer Access Charge

a. Position of the Parties

(1) Department of General Services

DGS asserts that PG&E's proposal to make changes to the electric generators and cogenerators will result in the transfer of substantial costs from variable rates to fixed rates. For example, Table 14.1-12 in Exhibit 1 demonstrates that a noncore customer using 20,833 therms per month will experience a customer charge increase of 207%. DGS believes that these costs should be collected as a volumetric charge, collected on an equal cent per therm basis from all users, rather than included in the customer access charge. Also, moving costs from volumetric to fixed customer charges does not encourage conservation because the customer charge cannot be avoided.

(2) Mirant

Mirant recommends that the Commission reject the drastic and unsupported increases in customer access charges that PG&E has proposed.

PG&E proposes to revise its rate structure and rates for customer access charges. For large electric generator customers, PG&E's plan to convert from volumetric to fixed monthly charges, while adding two volume-defined tiers at the upper end, will produce greatly increased monthly charges. For example, an electric generator customer using 15 million therms of gas per month would face a customer charge increase from $12,000 to $19,600 per month, a 63% increase. An electric generator customer using 30 million therms of gas per month would face a customer charge increase from $24,000 to $43,000, an increase of 79%.

The CCC / Calpine witness, which Mirant co-sponsored, criticized PG&E's customer access charge proposal because PG&E's proposal is premised on the assumption of escalating capital expenditures to install metering on new power plants (from $1.6 million in 2001 to $5.1 million in 2004). Beach testified that this assumption is inconsistent with the recent slowdown of new power plants in the western United States. To align PG&E's customer access expense estimates with PG&E's own revised forecast of new power plant interconnections, Mirant recommends that the Commission adopt customer access charges based on capital additions of $2.5 million in 2002 and $1 million in each of 2003 and 2004.

Mirant agrees with NCGC's recommendation to defer PG&E's customer access charge proposal to the 2005 test year rate case to allow for further analysis. As noted by NCGC witness Pretto, PG&E's proposal would increase customer access charges by over 100%. NCGC also contends that PG&E has failed to justify deviating from precedent to impose fixed monthly customer access charges on electric generator and cogeneration customers, and has failed to explain how the proposed rate tiers were determined. Since PG&E has not justified its proposals, Mirant recommends that PG&E's proposals be rejected.

(3) NCGC

PG&E proposes to increase the revenue requirement associated with transmission-level customer access charges by over 100%. Current customer access charges recover approximately $6.4 million per year. Under PG&E's proposal, the revenue requirement for customer access charges would increase to $13.6 million for 2004. NCGC recommends that PG&E's proposed increase in the customer access charge revenue requirement be examined further and deferred to PG&E's test year 2005 rate case.

NCGC points out that PG&E's proposal to impose fixed monthly access charges on electric generators and cogenerators will increase the amounts paid by electric generators and cogenerators to cover access charge costs each month. The current all-volumetric access charge rate design for electric generators and cogenerators was adopted in PG&E's 1998 BCAP in D.98-06-073. The all-volumetric rate design was continued in PG&E's 2000 BCAP and has remained in place until now. Currently, the volumetric access charge component of electric generator and cogenerator rates is $0.0008 per therm. Electric generators and cogenerators pay that charge multiplied by the volumes that the customer uses on any given month.

NCGC asserts that the imposition of fixed monthly access charges will conflict with the all-volumetric rate design that has been in place for electric generators and cogenerators on the PG&E system since 1998, and it will conflict with the all-volumetric rate design that has been in place for electric generators and cogenerators on the SoCalGas system for many years. NCGC asserts that PG&E has provided no justification for deviating from precedent, and imposing the burden of fixed monthly access charges on electric generators and cogenerators. PG&E's proposal to impose fixed monthly access charges on electric generator customers should therefore be rejected.

PG&E also proposes to add two higher tiers to the six tiers of customer access charges currently set forth in Schedule G-NT for industrial customers. NCGC contends that PG&E has provided no explanation or justification for switching to an eight-tier structure for industrial customer access charges. PG&E has not explained how the tier values were selected, or how the volumetric parameters for the eight tiers are tied to the underlying service, regulator, meter costs, if there is any tie at all. In light of PG&E's failure to justify any of the details of the eight-tier structure, PG&E's proposal should be rejected.

(4) PG&E

Several parties have suggested that PG&E's proposed increase in the customer access charge is too high. PG&E contends that the evidence shows that customer access charges are too low, and does not fully cover the full cost of providing service to serve a significantly greater number of customers that PG&E serves today. The proposed increase was developed using a separate embedded cost of service study based on PG&E's experiences over the Gas Accord period, and the estimated facilities and operations costs in 2004.

Some parties advocate that the customer access charge issue be deferred. PG&E contends that deferring this issue will prevent PG&E from recovering its full cost of service.

b. Discussion

PG&E proposes to revise the transmission-level customer access charges to reflect the updated revenue requirement. PG&E proposes to continue the existing rate design methodology for industrial and wholesale customers for 2004. PG&E also proposes to add two higher usage tiers to the six-tiered industrial (Schedule G-NT) access charge, and apply the rate structure to all cogenerators and electric generators. PG&E also proposes to update the customer access charges for the core wholesale customers.

With regard to the updating of the customer access charges to reflect the revenue requirement, some of the parties contend that the amount requested is too high and should be deferred for further investigation. Some of the parties believe the customer access charges should be reduced to reflect the lower number of new plant connections. As discussed elsewhere in this decision, we have reduced the power plant connections and power plant metering costs. Since the O&M expenses and capital expenditures were at issue in this proceeding, resolution of the customer access charges will not be deferred.

PG&E contends that the increase in the customer access charges are needed because the current charges do not reflect the cost to provide service.

None of the other parties presented any evidence to show that the growth in connections of electric generators over the last seven years has not raised PG&E's costs to connect these additional customers.

The next issue is whether two additional tiers should be added to the six tiers of access charges that are currently set forth in Schedule G-NT. Under PG&E's proposed customer access charges, shown in Table 14.1-12 of Exhibit 3, the rates for these new tiers would go from $3,892.38 to $19,615.11 for Tier 7, and to $43,148.69 for Tier 8. The other six tiers would see their rates increase by approximately 100%.

These two new tiers, along with Tier 6, will bear the brunt of the increases if these additional tiers are added. Aside from PG&E's prepared testimony regarding the customer access charges, PG&E has not provided any other citations to the record in this proceeding in support of the additional two tiers. (*See* PG&E Opening Brief, pp. 64-66, 97.) PG&E has not provided sufficient evidence to support its proposal to add Tiers 7 and 8 to Schedule G-NT. Therefore, PG&E's proposal to add these two tiers is not adopted.

Unfortunately, transmission-level customer access expenses have gone up, and that burden will be spread to the six tiers and to wholesale customers.

PG&E's other proposal is to apply the customer access charges in Schedule G-NT to electric generators and cogenerators, who will take service under Schedule G-EG. Currently, electric generators and cogenerators are charged an all-volumetric access charge is $0.0008 per therm. Under PG&E's proposal, electric generators and cogenerators would pay a fixed customer access charge, instead of a volumetric charge. Under the fixed charge, an electric generator or cogenerator could end up paying more than it would under the existing volumetric charge. (9 RT 981-982.)

NCGC points out that this volumetric charge was proposed by PG&E and adopted in PG&E's 1998 BCAP in D.98-06-073 (80 CPUC2d 604), and continued in the 2000 BCAP in D.01-11-001. Although the volumetric customer access charge was developed in PG&E's BCAP, this is an appropriate place to consider PG&E's proposal to apply the rates in Schedule G-NT to Schedule G-EG since one of PG&E's other proposals is for a single electric generation class.

We have considered the concerns of Mirant and NCGC. The cost of service for transmission-level customer access has been reduced as a result of the adjustment to power plant connections and metering. Unfortunately, the customer access expenses have increased over the years as new electric generation customers were added. We will adopt PG&E's proposal to apply the Schedule G-NT customer access charges, as revised in this decision, to all cogenerators and electric generators instead of the volumetric customer access charge.

PG&E shall be permitted to update its cost of service for transmission-level customer access to reflect the cost of service as adopted in today's decision. PG&E shall continue to use the existing six-tier structure for Schedule G-NT access charges, including the existing cost allocation, and shall apply those customer access charges to all cogenerators and electric generators. PG&E shall continue to use the existing cost allocation for wholesale customer access charges, which reflects the adopted costs of service and adjustments.

The adopted customer access charges are shown in Table 12 of Appendix A.

2. Customer Class Charge

a. Position of the Parties

(1) TURN

TURN supports PG&E's proposal to collect the distribution revenue requirement through a distribution rate component in the customer class charge for the industrial transmission customer class. TURN points out that the distribution costs attributable to these industrial customers are not paid by them, but are instead shifted to other distribution-level customers and PG&E shareholders. TURN contends there is no justification for this subsidy, which was approved as a detail of the Gas Accord settlement.

b. Discussion

PG&E proposes that the distribution costs allocated to distribution-level customers served from transmission-level rate schedules be recovered through a distribution rate component in the customer class charge for the industrial transmission customer class. PG&E states that this proposal will result in a slight increase in rates for industrial transmission customers, and a slight decrease in rates for all remaining distribution-level customers.

Prior to the Gas Accord, the distribution costs attributable to industrial transmission customers were collected through a distribution rate component in the rates paid by all industrial transmission customers. The Gas Accord eliminated this distribution rate component, and reallocated the costs to all remaining distribution-level customer classes. In D.98-06-073, a settlement was reached where the treatment of distribution-level costs allocated to industrial transmission customers was allocated 50% to PG&E's shareholders, and the other 50% was allocated to the other distribution-level customer classes for the remainder of the Gas Accord. D.02-08-070 extended this rate treatment through 2003.

TURN is in favor of PG&E's proposal to impose a distribution rate component on the industrial transmission customer class. No one opposes the proposal.

We adopt PG&E's proposal to impose a distribution rate component on the industrial transmission customer class in order to recover the distribution costs allocated to this class. This change will align the costs with the customer class that should pay for it, instead of having such costs subsidized by a different customer class and by PG&E's shareholders.

PG&E also proposes that the cogeneration distribution shortfall account be eliminated, and that the distribution costs allocated to cogeneration customers[94] be recovered through a distribution rate component paid by cogeneration and electric generator customers. In the Gas Accord, the distribution rate component was removed, and these distribution costs were collected from cogeneration and UEG end-users through the cogeneration distribution shortfall rate component in the customer class charge. PG&E contends there is no rate impact from this proposal on any customer class.

No one opposes PG&E's proposal to eliminate the cogeneration distribution shortfall rate component in the customer class charge, and to replace it with a distribution rate component in the customer class charge. We adopt PG&E's proposal.

The rate components, which make up the customer class charge will be determined in the BCAPs and Annual True-ups.

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[94] PG&E's proposal for a single electric generation class would allocate distribution costs equally to all cogeneration and electric generation end-users.

3. Transmission - Level Eligibility Criteria

a. Discussion

PG&E is proposing to change the transmission-level eligibility standard from a two-part standard to a single standard. Under the proposed single standard criteria, a distribution-level noncore customer will receive transportation service under transmission-level rate during any month when their historical 12-month usage is 3 million therms or higher. PG&E contends that the single standard will simplify the administration and monitoring of the eligibility, and allow eligible customers to pay transmission-level rates when they first become eligible, rather than waiting for the annual review of eligibility under the two part standard. PG&E also states that this proposal will not result in any cost shifts or rate impacts.

No one opposes PG&E's proposal to modify the transmission-level eligibility criteria. The proposal to use the single standard of eligibility for transmission-level rates is adopted.

4. Balancing Account Protection Proposal

a. Position of the Parties

(1) Duke

PG&E has proposed 100% balancing account treatment for its noncore distribution revenues. Under the Gas Accord, noncore distribution revenues are subject to throughput risk. PG&E's proposal, if adopted, would eliminate this risk.

Duke points out that SoCalGas received balancing account protection on an interim basis only, due to a delay in the processing of its BCAP. Duke also points out that the Commission stated that the 100% balancing treatment shall not set a precedent. (D.02-12-017, p. 9.)

b. Discussion

PG&E proposes that it be given 100% balancing account protection for its noncore distribution revenues. Under the Gas Accord, balancing account treatment for these revenues was eliminated. (73 CPUC2d 825.)

PG&E is raising the balancing account issue in this proceeding, rather than in the BCAP, because it seeks to reestablish what was in place before the Gas Accord. PG&E also points out that in D.02-12-017, SoCalGas received 100% balancing account protection.

The issue of balancing account treatment for PG&E's noncore distribution revenues should be raised in PG&E's next BCAP filing. The BCAP is the proceeding in which the forecasted throughput that PG&E complains of was calculated. We also note that SoCalGas' request for balancing account treatment was raised in its BCAP proceeding, and that the balancing account protection was only for an interim period.

Although the Gas Accord eliminated the balancing account treatment for PG&E's noncore distribution revenues, those distribution costs, revenues and throughput are addressed in the BCAP, which PG&E acknowledges. Any balancing account protection for distribution revenues should be addressed in the proceeding where those issues originate. Accordingly, the proposal to adopt 100% balancing account protection for PG&E's noncore distribution revenues is not adopted.

F. Single Electric Generation Class

a. Position of the Parties

(1) CCC/Calpine

PG&E proposes to create a single electricity generation class consisting of noncore merchant electric generators, PG&E's retained gas-fired power plants, cogeneration facilities, and solar electric generation load. The class would be segmented into distribution and transmission-level rates, with distribution-level customers using more than 3 million therms per year qualifying for the transmission-level rate. PG&E also proposes to eliminate the cogeneration gas allowance (CGA) and instead implement anti-gaming measures to ensure that only gas used for electric generation qualifies for electric generation gas rates. PG&E also proposes to eliminate the collateral discount rule (CDR), which requires that any discount offered to a non-cogenerator electric generator also be offered to cogenerators.

CCC/Calpine, along with Mirant, support the creation of a single electric generation class. The implementation of a single-EG class will close the gap between the electric generation rate design of PG&E and the Sempra gas utilities, which already has a single electric generation class. In the SoCalGas BCAP, the Commission adopted many of the changes that PG&E proposes here, including segmentation of the electric generation class, and the elimination of the CGA and the CDR.

CCC/Calpine have two concerns regarding PG&E's single electric generation class proposal. First, PG&E's proposal that all electric generation customers bear 75% of the distribution costs that otherwise would be allocated entirely to distribution-level customers, should be revised to allocate 100% of the distribution costs to distribution-level electric generation customers. Second, PG&E's proposed anti-gaming rules associated with the elimination of the CGA are unduly harsh and defeat the purpose of eliminating the CGA. In particular, PG&E should be required to use a customer-specific heat rate instead of a generic heat rate to calculate a cogeneration customers' electric generation gas usage.

PG&E's proposal that distribution-level electric generators should only bear 25% of the historical subsidy by transmission-level electric generators, is a compromise that does not adequately address a customers' actual cost of service and seeks to perpetuate inappropriate cross subsidies. PG&E basically admits this when it proposes to maintain 75% of the distribution-level subsidy in order to manage rate impacts to smaller distribution-level generators. PG&E's proposed distribution-level electric generation rate would only be $0.20 per Dth higher than the comparable transmission-level rate. This is only 2/3rd of the $0.30 per Dth differential that was approved by the Commission in D.00-04-060 at 53-56 for SoCalGas and SDG&E. Removing the entire subsidy for distribution-level electric generation customers would not be out of line with the differential in PG&E's existing industrial gas rates. PG&E's distribution-level industrial rate is $0.73 per Dth higher than the comparable transmission-level rate. Eliminating the subsidy of distribution-level electric generation customers would produce a transmission/distribution-level electric generation rate differential of $0.81 per Dth.

CCC/Calpine state that the elimination of the CGA is likely to benefit small, distribution-level electric generators that have relatively higher heat rates. For example, PG&E's proposed generic heat rate for cogenerators less than 5 MW is above PG&E's current CGA. Allowing all of the gas consumed by smaller electric generators to qualify for electric generation rates, which will continue to be lower than their otherwise applicable industrial rates, will reduce the smaller cogenerators' overall gas costs and mitigate at least some of the impacts associated with PG&E's rate segmentation proposal. As such, the Commission should fully implement the proposed distribution and transmission-level segmentation, as it has done for the Sempra electric generators and for PG&E's noncore industrial customers.

NCGC agrees with CCC/Calpine that the Commission should require PG&E to revise its proposal in order to require that distribution-level electric generation customers pay 100%, rather than merely 25%, of the distribution costs allocated to distribution-level electric generation service. CCC/Calpine agree with NCGC's assessment that the continued imposition of distribution-level costs on transmission-level customers, after adoption of a single, segmented electric generation rate would cause the transmission-level customers to continue to bear costs that they do not cause.

The second concern of CCC/Calpine with PG&E's single electric generation class is that PG&E proposes to employ anti-gaming rules that ensure that cogenerators only receive electric generation gas rates for gas used in electricity production, as opposed to gas used in industrial applications. CCC/Calpine contend that PG&E proposes to employ artificially high generic heat rates, as presented in Table 14-12 of Exhibit 3. CCC/Calpine assert that the Commission should reject PG&E's proposal to use generic heat rates for a number of reasons. First, it amounts to an attempt by PG&E to enforce an efficiency standard for electric generators. If implemented, PG&E's proposal would improperly regulate efficiency because generators would have to pay a higher gas transportation rate if their equipment is not as efficient as PG&E's generic heat rate. Setting such an efficiency standard is not the purpose of the anti-gaming rules. Rather, the purpose is to ensure that the electric generation gas rate applies only to gas used for electric generation.

CCC/Calpine state that the CGA, which PG&E proposes to abolish, is a mechanism that limits cogenerator's access to electric generation gas rates based upon their operational efficiency relative to other electric generators. The Commission abandoned the CGA in the SoCalGas BCAP because cogenerators and other electricity generators are now competing, and a mechanism such as the CGA is neither necessary to promote economic efficiency nor desirable, as it would put cogenerators at a competitive disadvantage vis-a-vis other generators. CCC / Calpine contend that it makes no sense to eliminate the CGA, only to replace it with a new mechanism that regulates the efficiency of cogenerators, which CCC / Calpine contend is actually more restrictive than the CGA. While PG&E's current CGA is 10,681 BTU / kWh, PG&E would cut off access to the electric generation gas rate at 9,000 BTU / kWh using PG&E's proposed generic heat rates for cogenerators of 10 MW or greater. Such a proposal cannot be accepted.

CCC / Calpine also state that PG&E's proposal on the heat rate does not accomplish the goal of deterring potential gaming. PG&E's witness agreed on cross examination that cogenerators with a heat rate lower than PG&E's generic heat rate can obtain electric generation rates for gas that is used for industrial purposes. (9 RT 972) Also, PG&E's heat rate proposal will improperly assess industrial rates to gas that is used to generate electricity by cogenerators whose heat rates are higher than the applicable generic heat rate. (*See* 9 RT 968.)

PG&E's witness also acknowledged that the anti-gaming mechanism should not deprive cogenerators of electric generation rates for gas used in the cogeneration of electricity, stating that "in the event of a customer that thought that 100 percent of his gas was not qualifying, PG&E would certainly be willing to entertain a customer-specific heat rate for purposes of measuring gas usage." (9 RT 972.)

CCC / Calpine contend that the Commission should simply extend the Sempra anti-gaming mechanism to PG&E and require PG&E to employ customer specific heat rates. There is no reason to require cogenerators to make a showing to PG&E in order for PG&E to agree to use customer-specific heat rates.

CCC/Calpine assert that the arguments of RealEnergy, Inc. (RealEnergy) and DGS are not valid criticisms. First, CCC/Calpine point out that these two parties did not participate in the hearings, and presented no evidence demonstrating that distributed generation would either be discouraged or rendered uneconomic as a result of the proposal to institute a single electric generation. Second, while encouraging distributed generation is a laudable goal, the Commission should not use hidden subsidies in gas rates, paid by other electricity generators, in order to achieve this goal. Rather, programs to encourage distributed generation should be purposefully developed, while ensuring that the cost of any such program is of an appropriate magnitude, and is levied against appropriate parties.

(2) DGS

DGS opposes PG&E's proposal to make changes to the electric generation class. The proposed changes would include eliminating electric generation parity for smaller cogeneration facilities, and transferring substantial costs from variable to fixed rates.

With respect to cogeneration parity, DGS points out that Commission policy has been to allow generators to compete on the basis of efficiency and not on artificial rate differentials. PG&E's proposal would essentially eliminate the right of smaller distributed generation to obtain the same gas transportation rates afforded to larger generators. DGS recommends that electric generators, regardless of size, pay the same basic rate.

(3) NCGC

PG&E proposes several changes to the design of its electric generation rates to align its rate design structure with changes resulting from electric industry restructuring, and with SoCalGas' and SDG&E's electric generation rate structure.

NCGC supports the changes that PG&E proposes. NCGC contends that the segmented electric generation rates will provide a more accurate price signal for potential generation projects that are considering locating in PG&E service territory.

NCGC contends that PG&E's proposal for a single, segmented electric generation class is consistent with the single, segmented electric generation class on the SoCalGas and SDG&E systems, which was adopted in D.00-04-060. Since D.00-04-060 found that the segmented transportation rate for SoCalGas and SDG&E complied with the cogeneration parity requirements of § 454.4, PG&E's proposal should comply as well.

NCGC also supports the elimination of the CGA and supports the adoption of anti-gaming measures, primarily the requirement that there be a separate PG&E meter to measure gas use at electric generation facilities. NCGC also supports elimination of the CDR, since parity is achieved through the single, segmented electric generation rate.

PG&E proposes that for 2004, distribution-level electric generation customers be required to pay a distribution rate component that reflects only 25% of the distribution costs allocated to distribution-level electric generation service. Under PG&E's proposal, the remaining 75% of the distribution costs allocated to the distribution-level electric generation customers would be spread equally to all transmission and distribution-level electric generation customer volumes.

NCGC is opposed to the phase-in of distribution-level costs. Such a phase-in is inconsistent with what occurred on the SoCalGas and SDG&E systems, where there was no phase-in provision. NCGC believes that the same should be done here. NCGC contends that transmission-level customers do not cause PG&E to incur distribution-level costs. Continuing to impose distribution-level costs on transmission-level customers after the adoption of a single, segmented electric generation rate would be unfair to transmission-level customers to bear costs that they do not cause.

Although PG&E claims that a phase-in would manage the rate impact of segmentation on smaller distribution-level generators, NCGC contends that PG&E has not provided any evidence that the rate impact of full rate segmentation on distribution-level generators would be unmanageable for those generators. PG&E's proposal to phase-in electric generation rate segmentation should be rejected.

(4) RealEnergy

RealEnergy is a provider of small-scale distributed generation projects.

PG&E proposes the creation of a single electric generation class, with the class segmented by transmission and distribution service levels. Customers who use 3 million therms or greater would be considered transmission-level. Under PG&E's proposal, RealEnergy's facilities would be considered distribution-level.

Currently, the distribution costs allocated to distribution-level electric generation customers are spread equally to all transmission and distribution-level electric generation customers. Under PG&E's proposal, distribution-level electric generation customers would pay a distribution rate component based on 25% of the distribution costs allocated to distribution-level electric generation and cogeneration customers. The remaining 75% of the distribution costs allocated to distribution-level customers would continue to be spread equally to all transmission- and distribution-level electric generation customer volumes through the distribution rate component.

RealEnergy favors keeping the current rate structure. RealEnergy points out that the cost of the gas resource can make or break a small on-site generation project. The adoption of a rate structure that renders a project uneconomic would be counter to the benefit such a structure would provide. The Commission should avoid imposing massive rate shock on individual customer classes without serious cause or efforts to mitigate such impacts.

If the Commission decides not to retain the current rate structure, then RealEnergy supports PG&E's proposal for the 25%/75% apportionment. PG&E's proposal would at least try to mitigate the rate shock such customers would feel if PG&E's single electric generation class were fully implemented. RealEnergy contends that the opposition of CCC/Calpine and NCGC to PG&E's 25%/75% phase-in does not consider the important public policies for fostering distributed generation.

(5) PG&E

PG&E proposes to establish a single, electric generation class, which includes all noncore electric generation, qualifying cogeneration, and solar electric generation load. This proposal is in response to the February 26, 2002 scoping memo, and finding of fact 10 in D.01-11-001.

b. Discussion

PG&E proposes to create a single electricity generation class consisting of noncore merchant electric generators, PG&E's retained gas-fired power plants, cogeneration facilities, and solar electric generation load. Under PG&E's

proposal, electric generation customers would be segmented into distribution level or transmission-level customers.

PG&E's proposal was made in response to the scoping memo, which asked if segmenting of PG&E's electric generation rates should be addressed in this proceeding. (Scoping Memo, p. 6.) NCGC had raised the segmentation issue in PG&E's 2001 BCAP, and as part of the settlement adopted in that proceeding, the parties agreed to defer the segmentation issue to the Gas Accord II settlement discussions. (*See* D.01-11-001, FOF 10.F.4).

DGS opposes PG&E's proposal because the new Schedule G-EG will prevent smaller distributed generation facilities from obtaining the same gas transportation rates.[95] DGS believes that this will discourage the development of such facilities.

In deciding whether PG&E's single electric generation class should be adopted, we first consider DGS' opposition to the proposal. DGS' argues that distributed generation facilities will be prevented from obtaining favorable gas transportation rates. DGS did not present or cite any evidence in the record about what the consequences might be for distributed generation if the single electric generation class proposal is adopted. Despite this circumstance, it appears from our review that a policy cutoff of 250,000 therms prevents new projects from qualifying for electric generation rates. This change in policy towards small distributed generators and cogenerators would be in contradiction

[95] In DGS' opening brief, DGS takes issue with the customer access charge shown in Table 14.1-12 of Exhibit 3. DGS, however, did not present any witnesses or ask any questions of the available witnesses about the development of the customer access charges. The customer access charges, and the expenses which feed into the charges, has been addressed earlier.

of the framework established in the Energy Action Plan (adopted by the Commission) that promotes alternative sources of energy as an important resource that is both reliable and environmentally sustainable.

Despite DGS' lack of participation, it appears from our review that a policy cutoff of 250,000 therms prevents new smaller projects from qualifying for the single electric generation class. Although PG&E's proposal to revise the grandfather cut-off date would allow approximately 23 new cogeneration customers, who were coneected during 2003, to be grandfathered, new distributed generation coming on line after December 31, 2003 would be harmed by such a cutoff. DGS is also concerned that under PG&E's proposal, distributed generators will have procure the gas from third parties.

We have considered PG&E's proposal, and the concerns of DGS. We will eliminate the 250,000 therm cutoff from PG&E's proposal, but retain the proposed requirement that these customers obtain their gas from a third-party supplier.

In D.00-04-060, we adopted a single electric generation customer class for the two Sempra utilities, SoCalGas and SDG&E. The electric generation rate for SoCalGas and SDG&E was segmented by throughput level. The CDR and the CGA were eliminated. The decision also concluded that the single electric generation customer class for the Sempra utilities complied with § 454.4. (D.00-04-060, pp. 54-55, 154.)

PG&E's proposal for a single electric generation customer class is similar to what was adopted in D.00-04-060, including the elimination of the CDR and CGA. There are two notable differences between PG&E's proposal and the one that was adopted for the Sempra utilities. First, the segments for Sempra are divided by throughput levels, either above or below three million therms. The

PG&E proposal segments by dividing the class into distribution and transmission service levels.

Although the segments differ between PG&E's proposal, and what we approved in D.00-04-060, the segments are still based on throughput and service level. PG&E's proposal for a single electric generation customer class, like the one adopted for the Sempra utilities, attempts to treat electric generators alike. We adopt PG&E's proposal for a single electric generator class. As the proposal for a single electric generator class is designed it appears that both distributed generators and cogenerators that use less than 250,000 therms per year would have a significant impact on encouraging the development of new small generator projects in northern California.

The second difference between PG&E's proposal and what was adopted for SoCalGas is the anti-gaming measure. Since the CGA is eliminated, the purpose of the anti-gaming measure is to ensure that the gas qualifying for the electric generation rate is being used to generate electricity. If no metering is available to measure gas usage at the electric generation facility, PG&E proposes that the gas volumes be measured "using other gas metering devices and by the recorded net electric generation's output in kilowatt hours (kWh) multiplied by the average heat rate for similarly sized EG facilities, as classified in Table 14-12." (Ex. 3, p. 14-38.)

The SoCalGas tariff provides that the customer will be billed the lesser of total metered throughput, or "an amount of gas equal to the customer's recorded power production in kilowatt-hours (KWH) times the average heat rate for their electric generation facilities." The tariff also provides that when required, the "electric generation customers will provide the utility with the average heat rate for electric generation equipment as supported by documentation from the manufacturer." If that is not available, the "operating data shall be used to determine customer's average heat rate." (SoCalGas, Schedule GT-F, Special Conditions 19, 20; *See* Ex. 6, p. 48, Att. RTB-4.)

CCC / Calpine disagrees with PG&E's proposal to use the average heat rate for similarly sized facilities as shown in Table 14-12 of Exhibit 3. PG&E did not respond to the CCC / Calpine suggestion to use the same rules that SoCalGas uses in its Schedule GT-F tariff. (*See* Ex. 6, p. 48.)

We have compared the method proposed by PG&E, and the method that SoCalGas has been authorized to use. The methods are very similar in that a meter must be used unless it is not economically feasible to do so. The methods differ though when it comes to measuring gas usage if no metering is available. We agree with CCC / Calpine that PG&E's use of an average heat rate for similarly sized electric generation facilities may not correctly reflect the customer's actual heat rate. Instead of PG&E's proposed method of measuring usage, the method set forth in SoCalGas' Schedule GT-F tariff in Special Conditions 19 through 22 shall be used.

In its comments to the proposed decision, PG&E requests that in order to accommodate the adopted anti-gaming measure, it be given a three-month delay, until April 1, 2004, to implement the single EG class. During that interim period, PG&E will apply the 2004 adopted revenue requirement allocated to electric generation and cogeneration customers to its current rate design structure, in its customer access and distribution rate components. (See Appendix A Table 14, page 17,) We adopt PG&E's interim actions as it moves forward to implement the single EG class.

PG&E proposes to separate electric generators into two classes: (1) transmission-level customers and (2) distribution-level customers. RealEnergy and CCC / Calpine disagree with how the distribution costs that are allocated to distribution-level electric generation customers should be paid. PG&E proposes that to mitigate rate shock to distribution-level electric generation customers, that they be allocated 25% of the costs, and the remaining 75% be spread equally to all transmission and distribution-level electric generation customer volumes through the distribution rate component. RealEnergy favors the existing allocation of spreading these costs equally to all transmission and distribution-level electric generation customers. In the event the existing allocation is not retained, RealEnergy favors PG&E's 25% / 75% proposal.

CCC / Calpine and NCGC believe that distribution-level electric generation customers should pay 100% of the distribution costs that are allocated to them, instead of transmission-level electric generation customers having to subsidize part of the remaining 75% of the distribution-level electric generation customers' distribution costs. The testimony of the CCC / Calpine witness points out that the differential between PG&E's distribution-level industrial rate is $0.73 per Dth higher than PG&E's comparable transmission-level rate. If the subsidy of distribution-level electric generation customers was eliminated, the differential between PG&E's electric generation distribution-level and transmission-level would be $0.81 per Dth.

We have considered the financial impact on both distribution-level and transmission-level electric generation customers. Although we are sympathetic to the transmission-level electric generation customers' concern, we believe that despite PG&E's best efforts to remedy such impacts, there still is a substantial rate shock on these distribution-level customers. Accordingly while adopting PG&E's proposal for a single electric generation class, we retain the current cost allocation that is already in place. We adopt PG&E's present method of allocating these costs equally to all distribution and transmission-level customers. As a result of continuing this current design, the rates shown in Table 12 of Appendix A are likely to change. PG&E is directed to file an advice letter within 30 days to reflect how the distribution costs allocated to distribution-level electric generation will be recovered.

We note the Legislature expressed a policy preference for renewable, ultra-clean and low-emission customer generation, as codified in specific statutes such as AB 970, SB 28X, SB 1038, and AB 1685. Collectively, these statutes directed the Commission to develop tariffs, financial incentives, and efficiency and emissions standards to encourage installation of distribution-level customer systems. Additionally, Public Utilities Code Section 353.2 expressly authorizes the Commission to consider the efficiency and emissions performance of distributed generation when establishing rates and fees. In D.03-04-030, we recognized the Legislature's policy to encourage certain types customer generation by exempting the departing load of small, renewable and ultra clean customer systems from certain costs. In recognition of past Commission policies, and the currently adopted guidelines established by the Energy Action Plan, we retain the current cost allocation that is already in place for distribution-level electric generation customers. PG&E may revisit this issue in the next phase of the Gas Accord. We direct PG&E to file an advice letter within ten days of this decision that develops a customer access charge that reflects our determination that rates for distribution-level electric generators are to remain as currently calculated (see Table 12 on page 14).

PG&E's proposal for a single electric generation customer class, as described at pages 14-36 to 14-39 of Exhibit 3, and as revised by our discussion above.

XIV. Contingency Rate Adjustments

A. Summary of Proposals

PG&E proposes the adoption of certain mechanisms to adjust rates for changes in costs in 2004 that are driven by external events.

The primary adjustment proposed by PG&E is a Governmental Mechanism that covers cost increases or decreases that are caused by government or regulatory actions in 2004. In the Gas Accord, these contingencies were referred to as z-factors. PG&E's proposed Governmental Mechanism would replace the z-factor adjustment.

The costs covered by the Governmental Mechanism would be limited to those caused by government actions. That means the change must be approved or enacted by the legislature, a regulatory agency, or other governmental entity before any adjustment will be made. Examples of such adjustments include, but are not limited to, changes to federal and state income tax rates, revised pipeline safety regulations, new requirements related to pipeline security, new or revised consumer protection legislation and regulations, and changes in environmental regulations.

The Governmental Mechanism would include the total net adjustment to the annual cost of service resulting from the government action from the date the costs were first incurred through the remainder of 2004. It would cover both capital-related and expense-related costs or credits, including a provision for any changes in franchise fees and uncollectible accounts expense.

PG&E notes that cost contingencies related to events up to December 31, 2003, may not have been included in the 2004 cost of service. If such an event occurred, then PG&E may update its rates to reflect any remaining unrecovered costs, or cost reductions, in the Governmental Mechanism or BCAP.

PG&E proposes that the amount of this cost of service adjustment, up or down, be tracked in a memorandum account with interest, until the change can reflected in rates for 2004. Any potential adjustment resulting from the Governmental Mechanism would be made by advice letter filing directly to the gas transmission and storage rates, with rates effective five business days after filing, subject to refund as described in Chapter 15 of Exhibit 1.

To minimize the effects of the adjustments on 2004 rates, PG&E proposes an annual sharing of the net cumulative balance of cost of service amounts recorded in the memorandum account associated with the Governmental Mechanism. PG&E proposes that the sharing responsibility be as follows: (1) the net 2004 cost or saving balance for the accumulated adjustments of $5 million or less be shared equally between ratepayers and shareholders, after tax; (2) the net 2004 cost or saving balance in excess of $5 million be the responsibility of ratepayers. Under the current z-factor mechanism, if the costs or savings are in the zero to $5 million range, the cost responsibility lies with PG&E. For costs or savings more than $5 million to $10 million, the cost responsibility is shared 50/50. If the costs or savings are more than $10 million, the cost responsibility is 100% that of customers. (73 CPUC2d at 822.)

The second mechanism is the A&G adjustment, which would be a one-time charge made by an advice letter filing directly to gas transmission and storage rates. This adjustment would match the allocated and assigned A&G expenses in the 2004 gas structure with the final amounts from PG&E's 2003 GRC (A.02-11-017), plus escalation to 2004.

PG&E also proposes that the Catastrophic Events Memorandum Account (CEMA) and the Hazardous Substance Mechanism (HSM) remain in effect. The CEMA mechanism covers costs associated with disasters, such as earthquakes and floods, that are catastrophic and out of PG&E's control by their nature. The CEMA was authorized in Resolution E-3238. The HSM is for the clean-up of environmental contamination at PG&E's facilities. The HSM was authorized in D.94-05-020. The costs authorized pursuant to the CEMA and the HSM are recovered through the customer class charge, rather than in PG&E's base rates. Adjustments to the HSM and CEMA will be incorporated in transportation rates in the BCAP or the annual true-up of balancing accounts.

PG&E also states that it may file to adjust rates at other times in 2004 because of increases or decreases in PG&E's costs. PG&E notes that these filings would be subject to Commission approval. Such adjustments could include the following: (1) changes to the capital structure and cost of capital that may result from implementation of a plan of reorganization in PG&E's bankruptcy proceeding; (2) changes to the monthly balancing charge and terms of service, as recommended by the Balancing Forum; and (3) changes to certain aspects of the CAT program that may be recommended by the Core Procurement Advisory Group. PG&E does not propose that these rate adjustments be made subject to the sharing mechanism.

B. Position of the Parties

1. NCGC

NCGC asserts that PG&E's Governmental Mechanism is overly broad, fails to appropriately share costs between ratepayers and shareholders, and is unnecessary for the single year, 2004, covered by this proceeding. NCGC recommends that the Commission reject the proposed Governmental Mechanism.

NCGC contends that the z-factor adjustment that was adopted in the Gas Accord was narrowly drawn. It permits PG&E to adjust Gas Accord rates, but only if: (1) there are extraordinary costs or savings; (2) those extraordinary costs or savings are due to governmental action; and (3) the governmental action results in known changes. (*See* 73 CPUC2d at 822.) An example in the Gas Accord of a governmental action that could result in a z-factor rate adjustment is "changes to the federal or state income tax rate." (73 CPUC2d at 822.)

NCGC contends that PG&E's proposed Governmental Mechanism does not contain similar restrictions. There is no requirement that the Governmental Mechanism adjustment reflect extraordinary costs. Instead, the proposed mechanism could apply to rate changes that were linked to any governmental action, regardless of whether the impact on PG&E's cost of service was extraordinary or not. Nor is there a requirement that the governmental action must result in "known changes." NCGC contends that the Governmental Mechanism could be applied if there were revised pipeline safety regulations, new requirements related to pipeline security, new or revised consumer protection legislation, and changes in environmental regulations. The cost of these types of governmental actions could be quite uncertain.

NCGC also points out that PG&E's proposed mechanism for sharing the cost of the rate adjustments is far more favorable to shareholders than to ratepayers, as compared to the z-factor sharing mechanism. PG&E has not justified why a sharing formula that is less favorable to ratepayers should be adopted.

PG&E also proposes that it be permitted to apply the Governmental Mechanism to reach back retroactively to the time of the presentation of PG&E's testimony in this case to pick up cost of service changes that might be permitted under the mechanism. If the Governmental Mechanism is adopted, PG&E would be able to adjust its 2004 rates for events that occurred in 2003.

NCGC also contends that since this case involves rates for one year only, and given that PG&E will file a new application for 2005 rates, there is no need for a Governmental Mechanism or any other mechanism that would permit PG&E to adjust rates outside of a rate case for governmental actions of any sort.

2. ORA

ORA contends that there are significant PG&E proposals which impact ratepayers, but ORA could not properly review and assess these proposals in the course of this proceeding. One of these proposals that could significantly impact ratepayers is PG&E's contingency rate adjustments.

3. PG&E

PG&E asserts that NCGC was the only party to take issue in the opening briefs with PG&E's proposed contingency rate adjustments.

PG&E asserts that its proposal to replace the current z-factor mechanism with its proposed contingency rate adjustments is in the public interest and should be adopted. PG&E contends that the pipeline safety regulations are a prime example of why the current z-factor mechanism needs to be replaced with the proposed Governmental Mechanism. Although the pipeline safety regulations are not final, the final regulations will be implemented retroactively. Thus, these draft regulations will require substantial expenditures by PG&E beyond its normally anticipated cost of service. If other safety or security regulations are enacted or proposed that require expenditures by PG&E that are out of its control and unanticipated, PG&E's ratepayers should pay the cost of these regulations because they are part of the cost of providing the services to those customers.

C. Discussion

We have several concerns with PG&E's Governmental Mechanism. First, as described by PG&E, the mechanism would allow PG&E to reach back in 2003 to include costs in its gas transmission and storage rates and charges for 2004. As explained in PG&E's prepared testimony in Exhibit 1 at page 15-4, "If events occur which are not reflected in these costs, then PG&E may update rates to reflect any remaining unrecovered costs, or any cost reductions, under this adjustment…." Under the Governmental Mechanism, PG&E could essentially reopen the 2004 rates for this proceeding by reaching back to 2003 to include costs which PG&E did not originally include in its forecast of expenses. The mechanism opens the door to include significant costs on a retroactive basis.

The second concern with the proposed Governmental Mechanism is that it opens the door for what kind of adjustments could occur. Instead of limiting adjustments to "known changes due to governmental action," as D.97-08-055 requires for the z-factor, adjustments could be made for any change approved or enacted by a government body.

Our third concern with the Governmental Mechanism is that the proposed sharing mechanism is much more favorable to PG&E's shareholders as compared to the z-factor that was agreed to in the Gas Accord. Instead of PG&E absorbing the costs up to $5 million, under PG&E's proposal these costs would be shared 50/50 with ratepayers. If costs exceed $5 million, the costs exceeding $5 million would be the responsibility of ratepayers. Under the z-factor, ratepayers are not responsible for 100% of the costs until the costs are $10 million or more.

The proposed Governmental Mechanism is too broad, opens the door to a myriad of cost adjustments, and shifts these potential costs onto ratepayers. For these reasons, we do not adopt the Governmental Mechanism proposed by PG&E.

The z-factor adjustment of the Gas Accord shall be retained as part of the gas structure that we adopt for 2004 and 2005. We also authorize the continuation of the CEMA and the HSM mechanisms as contingency adjustments to the 2004 and 2005 gas structure.

PG&E mentions the A&G adjustment as a one-time adjustment to replace the A&G placeholder with the A&G expenses adopted in PG&E's GRC. PG&E shall be permitted to make that adjustment through an advice letter filing once the GRC is adopted. PG&E is authorized to establish a memorandum account to track the difference between the A&G expenses authorized in this decision, with the amount adopted in the 2003 GRC, escalated to 2004, plus interest.

PG&E also mentions that it may file to adjust rates at times other than the annual update of its gas structure rates because of increases or decreases in PG&E's costs. PG&E may file these kinds of applications, but it does not mean the Commission will entertain or approve them.

XV. PG&E Procurement Policy and Core Procurement Services

A. Summary

PG&E contends that the basic structure and rules for core procurement under the Gas Accord structure have worked well for core customers. Under the structure, PG&E's Core Procurement Department contracts for PG&E pipeline and storage services, as well as for interstate pipeline service. The Core Procurement Department is managed independently of the gas transmission and distribution systems, and operates at arms-length from PG&E's pipeline operator, CGT.

PG&E's Core Procurement Department manages its gas supply and transportation portfolio under the Core Procurement Incentive Mechanism (CPIM). The CPIM provides a market-based measure of the performance of PG&E's Core Procurement Department, and a means for the Commission to ensure the reasonableness of costs incurred on behalf of core customers.

PG&E recommends that the current CPIM structure and services be continued, with a couple of changes. PG&E's proposed changes to the rules for core suppliers and for PG&E's Core Procurement Department are due primarily to reliability concerns. PG&E proposes changes in four areas.

1. Proposals

a. Winter Firm Capacity Requirement Proposal

PG&E's first proposal is to increase the core firm capacity arrangements for CPGs. This is needed to meet the proposed Winter Firm Capacity Requirement, and to match potential new upstream holdings with downstream Baja capacity. There are two parts to this proposal.

Under PG&E's proposed Winter Reliability Standard, the core Winter Firm Capacity Requirement for the 2004-2005 winter season is 2,425 MDth/d. In order to meet this requirement, the first part of PG&E's proposal is to increase the core assignment of firm storage withdrawal by an additional 75 MDth/d starting in the winter of 2004-2005. This would increase core's firm withdrawal rights to about 1150 MDth/d on January 15, which is the point in the withdrawal season that best determines the need for storage to support the requirement.

The second part of PG&E's proposal to meet the Winter Firm Capacity Requirement is, to the extent capacity is available, the core's holdings of annual and/or seasonal firm Baja be tailored to match the firm interstate capacity holdings at Topock. The amount of firm interstate capacity at Topock held by the core is to be decided in Phase II of the El Paso Capacity proceeding, R.02-06-041. The maximum amount of El Paso capacity that could be allocated to the core is 204 MDth/d.

b. CPIM Proposal

PG&E's second proposal pertains to the CPIM. PG&E's CPIM was developed as part of the Gas Accord. (*See* 73 CPUC2d at 832.) PG&E's Core Procurement Department operates within the unbundled Gas Accord structure like any other shipper on the system. Under the CPIM, PG&E is incented to purchase gas and maximize the value of the assets retained by the core in order to provide the lowest reasonable cost gas to core customers. The CPIM defines the benchmark against which actual purchase costs are compared, and establishes the rules around the sharing of costs and savings calculated relative to the benchmark. If the costs incurred are below or above a range around the benchmark, PG&E is either rewarded or penalized by the sharing mechanism.

The CPIM structure is, to a large extent, dependent on the underlying transport and storage capacities held by the core. Given the current uncertainties surrounding the final disposition of the newly acquired El Paso capacity and PG&E's existing Transwestern holdings, PG&E is not proposing a specific incentive structure in this proceeding. Rather, PG&E believes that such a structure will be developed as part of the Phase II portion of the El Paso Capacity proceeding and/or through a separate application.[96]

[96] In D.02-07-037, the Commission ordered PG&E and other California utilities to acquire El Paso pipeline capacity to ensure access to the Southwest supply basins. In response to the decision, PG&E contracted for 204 MDth/d of firm capacity. In Resolution G-3339, PG&E was found to have complied with D.02-07-037, and that it met the conditions for recovery of existing and acquired capacity costs, including

Footnote continued on next page

PG&E proposes that the current CPIM be retained as a default structure in the event that anticipated modifications to the existing mechanism in the El Paso proceeding or a separate CPIM application are not approved by the Commission by the beginning of 2004. Any new structure that is developed in the other proceedings will become effective upon Commission approval. Also, the current CPIM or the new incentive structure should be amended to reflect the new core Winter Firm Capacity Requirement and the capacity additions that PG&E proposes.

c. Reliability Planning Proposal

PG&E's third proposal is to establish clear reliability planning standards. The proposal is designed to remove the ambiguity around Core Procurement's responsibilities in planning for peak-day events, and to eliminate the need for the alternate benchmark methodology in the current CPIM.[97] PG&E proposes that its Core Procurement Department be responsible for nominating supplies up to the pre-defined Winter Firm Capacity Requirement. If PG&E Core Procurement is unable to nominate supplies up to the Winter Firm Capacity Requirement and EFO noncompliance charges are incurred, charges arising from the difference between the predefined requirement and the amount of nominated supply will be considered a cost of gas with no offsetting adjustment to the standard CPIM benchmark. If core load exceeds the 1-in-10 level, Core Procurement will make

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Transwestern. The allocation of costs was left to Phase II of the El Paso Capacity proceeding. PG&E anticipates that a significant portion of the capacity will be dedicated to core use. PG&E states that the likely augmentation of the core's holdings of interstate capacity, and the change in status of PG&E's Transwestern contract, will result in significant modifications to the existing CPIM.

[97] According to PG&E, the alternate benchmark would be made obsolete by the adoption of the Winter Firm Capacity Requirement.

every effort to acquire the needed additional supplies, but the costs of these incremental supplies will be matched by an equivalent but offsetting adjustment to the standard CPIM benchmark. If the core load exceeds the 1-in-10 level and EFO noncompliance charges are incurred, the charges will be matched by an equivalent but offsetting adjustment to the standard CPIM benchmark.

Under the Winter Firm Capacity Requirement, the core has to contract for sufficient assets to meet an approximate 1-in-10 year cold weather event demand level. PG&E proposes that CPGs meet a two-part requirement which recognizes the fact that after January 15, the low temperature expected to occur once every 10 years is a system average composite temperature of 38 degrees Fahrenheit, while the corresponding temperature during the December 1 through January 15 timeframe is 35 degrees. The core load associated with a 38 degrees composite temperature is approximately 200 MDth/d lower (2225 MDth/d) than the core load associated with a 35 degree composite temperature (2425 MDth/d). Using a two-part standard allows for a more efficient use of the assets held by CPGs. If a one-part standard is used for the whole winter, CPGs would be required to hold in reserve storage inventory to meet loads that in the latter part of the winter have a very low probability of occurrence.

d. Tariff Change Proposal

PG&E's fourth proposal is to implement the rate changes resulting from its proposals in conjunction with the monthly core procurement advice letter filing in the month that the 2004 gas structure rates become effective.

PG&E proposes to make the following revisions to PG&E's gas Preliminary Statement to implement its procurement proposals:

1. PG&E proposes to revise the core backbone, interstate and Canadian capacity reservations. Canadian capacity costs are currently recorded in the core subaccount of the

Purchased Gas Account. PG&E proposes to record Canadian capacity costs in the core demand charge subaccount of the Core Pipeline Demand Charge along with other core pipeline demand charges, including additional capacity acquired to meet core needs. Since PG&E will retain the Gas Transmission-Northwest (GTN) capacity that is turned back by the gas ESPs, the tracking of the core transport portion of GTN capacity in the Core Transport Interstate Transition Subaccount of the CPDCA is no longer necessary.

2. In accordance with D.00-05-049, the core procurement portion of core storage costs is a component of the monthly core procurement price, effective October 1, 2000. The core transport portion of core storage costs is recovered through Schedule G-CFS. The core storage revenue requirement is recorded in the Core Firm Storage Account (CFSA). PG&E proposes to change the core storage reservation and to expand the applicability of Schedule G-CFS to include PG&E Core Procurement. The core procurement portion of storage costs will continue to be recovered in monthly core procurement rates. Minor changes to the CFSA will be made to implement the proposed changes.
3. PG&E proposes to revise Preliminary Statement Part C, Gas Accounting, Terms and Definitions, and the PGA, to reflect the revisions to the CPIM, including the proposal to remove the alternative benchmark and share the cost of EFO noncompliance charges.

2. Other Proposals

SPURR/ABAG propose that PG&E's Core Procurement Department be divested or spun off to a separate entity that is still owned by PG&E, and regulated by the Commission. SPURR/ABAG contend that such a proposal will reduce the cross-subsidies between core bundled sales customers and core transportation customer, eliminate the controversy over the proper level of PG&E's core brokerage fee, force the spun-off core procurement entity to deal with PG&E's distribution unit on an arm's length basis, and to make core customers aware that they have a choice between providers.

SPURR/ABAG also propose that PG&E's default core gas supplier be required to explain how it prices its gas sales to core customers.

B. Position of the Parties

1. SPURR/ABAG

PG&E states that it is the default provider of gas commodity service to core customers that do not elect core aggregation service. SPURR/ABAG acknowledges PG&E's role as the default supplier. However, SPURR/ABAG believes that there should be increased core customer awareness of the separation between PG&E's monopoly distribution function, on the one hand, and its non-monopoly procurement function on the other hand.

To ensure the separation between PG&E's monopoly function and PG&E's non-monopoly function, SPURR/ABAG propose that PG&E's core procurement group be divested or spun off to a separate entity that is still owned by PG&E and regulated by the Commission. This procurement entity would not share staff or administrative costs with PG&E's monopoly distribution company. The entity would be responsible for purchasing gas supply and reserving related transportation capacity and storage for bundled sales customers, and it would charge its gas sales customers the fixed and variable costs associated with its purchasing, selling, and billing functions. The fundamental purpose of SPURR/ABAG's proposal is to make core customers aware that they have a choice between default procurement service, and a competitive gas supply service provided by a third party supplier.

SPURR/ABAG contend that the establishment of a separate procurement entity would reduce the cross-subsidies between core bundled sales customers and core transportation customers, and would eliminate the controversy over the proper level of PG&E's core brokerage fee. Since the new entity would be responsible for all of the fixed and variable costs associated with the procurement function, the entity would assess an unbundled administrative fee that would presumably provide full recovery of all fixed costs associated with the procurement function.

Also, a separation of PG&E's monopoly and non-monopoly function would force the spun-off core procurement entity to deal with PG&E's monopoly distribution unit on an arm's length basis. The need for separation was highlighted by LGS and Wild Goose about the additional 75 MDth / d of firm storage withdrawal capacity and whether private storage providers should be able to provide this. The absence of arms-length dealings between PG&E's procurement department and its transportation department increases costs to bundled sales customers and makes it more difficult for third party suppliers to compete for sales to core customers.

One of PG&E's objections to the spin-off of its core procurement function is whether the spin-off would be consistent with § 328.2. SPURR / ABAG contend that the divestiture would be consistent with this code section because it would still be a gas corporation regulated by the Commission. This new gas corporation would perform part of the basic gas service referenced in § 328.2.

Another objection to the spin-off proposal is whether such a proposal should also apply to SoCalGas and SDG&E. SPURR / ABAG point out that such a proposal would make sense, but this proceeding is only addressing PG&E's market structure.

PG&E also questions whether the shareholders of the procurement entity should be placed at risk for recovering the fixed costs associated with maintaining a default core procurement service. SPURR/ABAG proposes that the procurement entity be at risk for the costs of procurement only if the Commission fails to provide recovery of these costs. SPURR/ABAG do not propose that the procurement entity should be denied recovery of any portion of its costs. Rather, the default supplier should be required to recover its fixed procurement costs (*i.e.*, administrative costs) through a separate charge to be fixed by the Commission.

PG&E also questions whether bundled core sales customers will still have the right to receive bundled gas service from their gas utility under traditional terms and conditions. SPURR/ABAG's proposal is not intended to change the terms and conditions of default procurement service. Rather, the proposal will ensure that the entity that performs the default procurement function is not the same as the entity that performs the distribution function.

2. TURN

TURN questions whether PG&E's proposals regarding core procurement are properly within the scope of this proceeding. These proposals include the additional core storage withdrawal reservation and the proposal that the core's annual firm Baja capacity reservation be increased by as much as 200 MMcf/d to match any potential additional core holdings of upstream El Paso capacity. TURN contends that it is not clear that upstream pipeline capacity necessarily has to be matched with firm annual capacity without some offsetting reduction in seasonal reservation. TURN asserts that these are complex and important issues that should be examined in a proceeding in which the parties have some advance warning that the issues are going to be raised.

3. PG&E

PG&E contends that the basic structure and rules for procurement have worked well for core customers under Gas Accord I. The intervenors have raised three issues relating to the proposed changes to the rules for core suppliers and for PG&E's Core Procurement Department. These issues are: (1) the Winter Firm Capacity Requirement; (2) the proposal to match El Paso capacity allocated to the core with Baja capacity; and (3) SPURR/ABAG's proposal to spin-off PG&E's Core Procurement Department from the distribution utility.

PG&E states that the assignment of the 75 MDth/d of additional storage withdrawal simply formalizes PG&E Core Procurement Department's contractual arrangement since 1998. In order to meet the core Winter Firm Capacity Requirement, PG&E's Core Procurement Department proposes that it reconfigure its winter storage withdrawal profile to provide an additional 75 MDth/d of peak withdrawal capacity in December and January when temperatures are the coldest and demands are the highest. This early winter withdrawal capacity increase is merely an adjustment or exchange of existing withdrawal capacity. The additional withdrawal capacity in November, December and January is offset by reducing peak capacity available to core customers in late February and March, when the possibility of a cold weather event is much lower, and core's current withdrawal rights exceed forecasted needs. PG&E asserts that there is no change in net withdrawal capacity available to core customers during the winter season as a result of the exchange. Since the institution of the Gas Accord, this exchange has been accomplished by way of a peaking agreement on a year-to-year basis.

TURN argues that PG&E's proposal to match upstream capacity with downstream Baja capacity is outside the scope of this proceeding. PG&E

contends that this issue falls squarely into the continuation of and possible adjustments to the CPIM and should be considered. PG&E asserts that the issue is one of determining the appropriate mix of firm capacity holdings that will ensure the highest value to the core during the periods when the actual physical utilization of capacity by the core will vary depending on the relative price relationships between the various sources of gas, as well as the overall level of core demand.

SPURR/ABAG proposes that PG&E place the core procurement function into a wholly-owned subsidiary of the utility. PG&E opposes SPURR's proposal because the current structure creates a fair and reliable competitive environment for all core customers. In addition, SPURR/ABAG has not presented a case that there is any discernable benefit to the majority of core customers. SPURR/ABAG's proposal may also violate Assembly Bill 1421 (Stats. 1999, ch. 909, § 4) and § 328.2, which require utility gas companies to provide basic gas service to all core customers in their service territory unless the customer chooses another provider. If the Commission decides to further examine this proposal, PG&E recommends that it be done in a separate proceeding.

PG&E strongly supports retaining the use of a gas procurement incentive structure in 2004, and believes that the concept of a procurement incentive mechanism should remain an integral part of the Gas Accord process. However, the CPIM structure is, to a large extent, dependent on the underlying transport and storage capacities held by the core. Due to current uncertainties surrounding the final disposition of the newly acquired El Paso capacity and PG&E's existing Transwestern holdings, PG&E cannot propose a specific incentive structure in this testimony. PG&E believes that a viable structure will be developed during 2003 as part of the Phase II of the El Paso Capacity proceeding, and / or through a separate application. PG&E proposes that this proceeding incorporate the revised mechanism subject to further amendments that result from changes that are specific to this proceeding.

C. Discussion

PG&E recommends that the current CPIM structure and services be continued, and that changes be made in four areas.

The current CPIM was originally approved as part of the Gas Accord settlement in D.97-08-055. (73 CPUC2d 770, 832.) In this proceeding, PG&E did not propose an updated CPIM because the outcome of Phase II of the El Paso proceeding is still not known. PG&E's testimony states that:

> "PG&E believes that a viable structure will be developed during 2003 as part of the Phase II of the El Paso Capacity Proceeding and / or possibly through a separate application. PG&E proposes that Gas Accord II – 2004 will incorporate the revised mechanism subject to further amendments that result from changes that are specific to Gas Accord II – 2004." (Ex. 1, p. 16-11.)

Then at page 16-13 of Exhibit 1, PG&E states:

> "The current CPIM will be retained as a default structure in the event that anticipated modifications to the existing mechanism, resulting from the outcome of Phase II and / or a separate CPIM application are not approved by the Commission by the beginning of the Gas Accord II – 2004 period. Any new structure developed as a result of the above mentioned proceedings will become effective upon Commission approval. Under Gas Accord II – 2004, the default mechanism or the newly modified incentive structure will be further amended to reflect the new Winter Firm Capacity Requirement and the above mentioned capacity additions."

The above testimony is important because it affects the changes that PG&E has proposed, as we discuss below.

The first proposal that PG&E requests is to increase the core's firm capacity holdings to meet the proposed Winter Firm Capacity Requirement. PG&E proposes that this be accomplished by increasing the amount of peak withdrawal capacity assigned to the core by 75 MDth/d starting in the winter of 2004-2005. The second increase would come from tailoring the core's holdings of annual and/or seasonal firm Baja transmission capacity to match the firm interstate capacity holdings at Topock.

As discussed earlier, we do not adopt PG&E's proposals for a Winter Reliability Standard and for a Winter Firm Capacity Requirement. Therefore, the proposed assignment of 75 MDth/d of storage withdrawal capacity to the core is not needed. Since the Winter Firm Capacity Requirement proposal is not adopted, the proposal to increase the core firm storage assignment through the 75 MDth/d of withdrawal capacity is not adopted.

PG&E acknowledges that the amount of firm interstate capacity at Topock will be decided in Phase II of the El Paso proceeding. Although PG&E has proposed in that proceeding that the interstate capacity be assigned to the core, we have not yet adopted a decision in that phase of the proceeding. Also, if additional capacity is assigned to the core, the above quotations contemplate that the CPIM be modified to include the additional capacity in the CPIM. Since neither the interstate capacity issue nor the modification of the CPIM has occurred, it appears that the shaping of any Baja capacity to match the interstate capacity is best left to either the El Paso proceeding, or a proceeding where modifications to the CPIM are being looked at. Accordingly, we decline to adopt PG&E's shaping proposal at this time.

PG&E's second proposal is to retain the current CPIM as the default structure in the event the anticipated modifications to the existing CPIM in the El Paso proceeding or a separate CPIM application are not approved by the Commission by the beginning of 2004. PG&E also proposes that if the current CPIM is retained as the default, that it be amended to reflect the core Winter Firm Capacity Requirement and the capacity additions that PG&E proposes.

As mentioned earlier, we have not taken any action yet on Phase II of the El Paso proceeding, and there is no separate application pending before the Commission to change the current CPIM. In addition, we do not adopt the Winter Firm Capacity Requirement, and we do not adopt the assignment of 75 Mdth/d of additional storage withdrawal capacity for the core. We will retain the current CPIM, as formulated in D.97-08-055, as the default incentive mechanism for PG&E's Core Procurement Department for 2004 and 2005, or until a revised CPIM is adopted by the Commission.

PG&E's third proposal is to clarify the Core Procurement Department's responsibilities regarding peak-day events. Specifically, PG&E proposes that the Core Procurement Department be responsible for nominating supplies up to the Winter Firm Capacity Requirement, and that the alternate benchmark methodology in the CPIM be eliminated. Since we do not adopt the Winter Firm Capacity Requirement, we do not adopt PG&E's proposal to clarify the reliability planning standards, and we do not adopt PG&E's proposal to eliminate the alternate benchmark in the CPIM.

PG&E's fourth proposal is for authorization to make a series of proposed tariff changes as listed earlier. Many of the proposed tariff changes which PG&E seeks are related to the Winter Reliability Standard, the Winter Firm Capacity Requirement, and the CPIM changes that PG&E requested. Since we do not adopt the Winter Reliability Standard, the Winter Firm Capacity Requirement, or the CPIM changes that PG&E requested, PG&E's proposed tariff changes are moot in some instances. In the event the other proposed tariff changes are consistent with the proposals or gas market structure that we adopt today, PG&E is authorized to make the necessary tariff changes.

SPURR/ABAG proposes that PG&E's Core Procurement Department be spun-off into a separate regulated entity. Although such a proposal sounds attractive for the competitive offering of core gas procurement, there are legal and structural hurdles to overcome. Section 328.2 states in part that "The commission shall require each gas corporation to provide bundled basic gas service to all core customers in its service territory unless the customer chooses or contracts to have natural gas purchased and supplied by another entity." This language suggests that PG&E's Core Procurement Department cannot be spun-off unless there is a structure that allows the gas corporation to continue providing bundled basic gas service. There are also some practical issues about how the spun-off utility will interact with other PG&E units, how it will be regulated, and what kind of regulations it should operate under. These issues are too complex to address in a proceeding with numerous other gas market structure issues. Accordingly, the proposal of SPURR/ABAG for PG&E to spin-off its Core Procurement Department is not adopted.

XVI. Core Aggregation Transportation Service

A. Summary

Core customers have the choice of being provided with default service by PG&E, or core gas customers may choose to take service from gas ESPs who serve core customers under the Core Aggregation Transportation (CAT) program.

The CAT program was originally adopted on a trial basis in D.91-02-040 (39 CPUC2d 360). In D.95-07-048 (60 CPUC2d 519) a settlement was adopted which modified the CAT program. D.95-07-048 also ordered PG&E and the two other gas utilities to submit core customer tariffs to unbundle interstate transportation rates.[98] As part of the Gas Accord, a number of provisions pertaining to core aggregation were addressed in the agreement. (*See* 73 CPUC2d at pp. 827 – 832.) The Comprehensive Gas OII Settlement Agreement, adopted in D.00-05-049, made changes to how gas ESPs serving core customers are provided with core storage.

PG&E proposes several modifications to the current transportation and storage capacity options for gas ESPs. PG&E contends that these changes are needed in order to adopt the program to the reliability and core procurement proposals that PG&E has proposed.

1. Winter Firm Capacity Requirement Proposal

PG&E's first proposal is that gas ESPs serving core customers be subject to the same Winter Firm Capacity Requirement that is proposed for PG&E's Core Procurement Department, as described in Chapters 4 and 16 of Exhibit 1. PG&E proposes that beginning in the winter of 2004-2005, all core suppliers, including gas ESPs, be required to hold firm capacity rights to meet a 1-in-10 year cold temperature event for the sum of the group's forecasted loads. PG&E contends that this requirement will help standardize the availability and

[98] In D.97-05-093 (72 CPUC2d 669), PG&E was authorized to unbundle the interstate portion of the transportation charges to core customers on the Pacific Gas Transmission Company (PGT) and El Paso pipelines for 1997. In D.97-12-032 (77 CPUC2d 100), PG&E was authorized to continue offering unbundled transportation rates on the PGT pipeline for 1998 and beyond.

reliability of core supply regardless of whether it is a gas ESP or PG&E's Core Procurement Department serving the load.

In order to allow gas ESPs to meet this requirement, PG&E proposes that gas ESPs be given an option to take a pro rata share of the PG&E core holdings that are outlined in Chapter 16 of Exhibit 1 and other contract rights that are included in PG&E's CPIM. To ensure that gas ESPs have the firm capacity needed to meet the Winter Firm Capacity Requirement, PG&E proposes that gas ESPs of significant size, *i.e.*, three percent or more of the core peak load, be required to provide documentation to PG&E of this capacity prior to the start of the winter season.

PG&E proposes that gas ESPs that serve less than three percent of the core peak load not be required to submit this verification. However, they will still be expected to hold, and will be offered, sufficient firm rights to meet this requirement. In PG&E's view, verification is not necessary because the flow order penalties create incentives to meet demand, and if the gas ESP fails to supply the gas, it is unlikely to have a large effect on the system.

2. Transportation Capacity Proposal

PG&E's second proposal is to offer to each gas ESP serving core customers an annual option to a pro rata share of each of the pipeline paths[99] held for core customers to: (1) Alberta-basin gas; (2) Southwest or Rocky Mountain-basin gas; (3) San Juan-basin gas; and (4) Topock gas. The pro rata allocation will be based

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[99] Currently, gas ESPS are offered, on a monthly basis, a pro rata share of core customer rights on the GTN, Redwood, and Baja paths.

on peak January loads of the gas ESPs' customer mix.[100] Gas ESPs will be offered and be required to take or reject[101] for the coming year of April through March, for each Core Transport path, a set of capacity rights in equal proportion to the amounts of each segment of the path as is held by PG&E for core customers and is included in the CPIM. During each month, as the gas ESP customer mix changes, their pro rata share will change and the amount of capacity assigned for the month on each path may change commensurately.

A gas ESP that holds rights on these paths may assign these rights. However, these rights are constrained by the one-month term of capacity assignments, the one-year pro-rata term, and the recall of capacity in the event customers return to PG&E from a gas ESP. Under PG&E's proposal, gas ESPs would have to agree not to enter into capacity releases or assignments with third parties that would restrict their ability to honor these recall-return requirements, and agree to hold PG&E harmless for any inability to fulfill these requirements.

3. Core Firm Storage Proposal

PG&E's third proposal is to continue offering storage held for core customers to gas ESPs on an annual basis. However, PG&E proposes a change in the way rejected capacity is treated, and the manner in which adjustments are made during the storage year. Under PG&E's proposal, the storage unbundling

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[100] According to PG&E the approximate customer population or mix of each CPG is known prior to each month based on the Direct Access Service Requests that have been received.

[101] PG&E proposes that all rejected or returned capacity become part of PG&E's Core Procurement Department portfolio and be part of the CPIM benchmark, and recovered in core procurement rates.

established in the Comprehensive Gas OII Settlement in D.00-05-049 will continue with the following changes:

- The elections for Core Firm Storage will be made as specified for transportation capacity. That is, a gas ESP will determine, prior to each April through March year, the percentage of its pro rata share of Core Firm Storage rights that it wishes to accept. That percentage of the pro rata share will be in effect for the gas ESP for the remainder of the storage year. A monthly adjustment structure will replace the generally optional mid-year and winter adjustments. Under this structure, if the gas ESPs' pro rata share of inventory changes by more than 10,000 therms, the supplier will have the opportunity to adjust its assignment. If the share changes by more than 100,000 therms, the adjustment will be mandatory. PG&E contends that the change to monthly adjustments will simplify administration of this program.
- The pro rata share for each CPG will be based upon peak January loads, instead of historical winter load, to be consistent with the core Winter Firm Capacity Requirement specified in Chapter 4 of Exhibit 1.
- The minimum monthly amount of gas that each CPG must hold in accepted Core Firm Storage will also be adjusted to account for the two minimum capacity steps of the Winter Firm Capacity Requirement. Minimum inventory limits will be enforced by monthly balancing adjustments during injection months, and by withdrawal limits during withdrawal months.
- All rejected capacity will become part of PG&E's Core Procurement Department portfolio and be part of the CPIM benchmark.
- Schedule G-CFS, Core Firm Storage, will apply to PG&E's Core Procurement Department and gas ESPs as discussed in Chapter 6 of Exhibit 1. Schedule G-CFS rates are discussed in Chapter 14 of Exhibit 1.

4. Core Aggregation Growth Proposal

PG&E's fourth proposal is not to allow gas ESPs to reject assignments of core transmission and storage capacity once the CAT program grows to serve ten percent of peak core loads. That is, once the CAT program serves ten percent or more of peak core loads, the storage and transportation options will become mandatory. PG&E contends that such a proposal is needed to limit the potential subsidy of the CAT program by the remaining 90% of bundled customers in the event gas ESPs reject large amounts of storage or transportation, and to support system reliability. PG&E proposes that this assignment of a full share of core transportation and storage resources begin in April, one year after the CAT program has achieved the ten percent level.

5. Information Proposal

SPURR/ABAG recommend that PG&E be required to publish additional information regarding the method and principles that pertain to computation of its monthly gas prices for core customers. SPURR/ABAG contend that PG&E's core customers lack sufficient information on how PG&E purchases its core gas supplies, and the pricing for such gas. In order for core customers to be aware of their gas supply choices, the customers must be able to understand how PG&E's gas is priced.

B. Position of the Parties

1. SPURR/ABAG

SPURR/ABAG act as agents for, and represent the interests of school districts and local governmental entities that purchase gas through the core aggregation program. The core aggregation program is an integral part of the Gas Accord structure.

SPURR/ABAG support PG&E's proposal to include Canadian capacity in the transportation options available to gas ESPs. However, they question the requirements that gas ESPs be required to accept an assignment of PG&E's reserved core capacity for one year, rather than for one month, and that a gas ESP must accept or reject all segments of a pipeline path.

SPURR/ABAG contend that PG&E's proposed change to require a core aggregation customer to make a one-year commitment, rather than a one-month commitment, in order to obtain a proportionate share of the pipeline capacity that PG&E has reserved for all of its core customers, would restrict the pipeline capacity options that are available to core aggregation customers. Under the current Gas Accord rules, a core aggregation customer, or its core aggregator, exercises a monthly option to accept all, some, or none of the proportionate share of the reserved core capacity on each pipeline segment that is held by PG&E for its core customers.

SPURR/ABAG assert that the monthly capacity option is a valuable benefit because it provides core aggregation customers with the flexibility to switch their purchases of capacity, and gas supplies, between and among the supply basins that provide the most economic alternatives. This allows core aggregators to minimize the delivered cost of gas for their core customers, while providing supply reliability. SPURR/ABAG point out that PG&E exercises the same flexibility with its capacity rights on pipelines delivering gas from Canada and the Southwest United States.[102] Also, core aggregation loads increase and decline over the course of a year. The monthly option can better accommodate these monthly fluctuations. An annual, rather than a monthly obligation, would

[102] SPURR/ABAG request that the Commission take official notice of PG&E's proposed treatment of its newly acquired El Paso capacity and its Transwestern capacity, as set forth in PG&E's prepared testimony in R.02-06-041.

restrict the core aggregator's ability to release temporarily unneeded capacity, and diminish the supply alternatives available to core aggregation customers.

SPURR/ABAG also point out that if the one-year capacity assignment is adopted, and the core aggregator's load declines during the one-year, a proportionate share of the core aggregator's capacity would have to be returned to PG&E so it can serve its returning core customer load. Essentially, the one-year assignment would be recallable, and that would make it very difficult for a core aggregator to release unutilized capacity to other parties and reduce the value of that capacity.

SPURR/ABAG are also opposed to PG&E's proposal that a core aggregation customer seeking to obtain a proportionate share of the core capacity on one leg of a pipeline path, must also obtain a proportionate share of the core capacity on every other leg of that pipeline path, (*i.e.*, the core transport path concept). SPURR/ABAG assert that this amounts to a rebundling of interstate and intrastate capacity rights for core aggregation customers, and is an unlawful tying arrangement and should be rejected.

Under the current Gas Accord rules, a core aggregation customer may elect to accept an assignment of PG&E's capacity on any one of the interstate and/or backbone pipelines on which PG&E reserves capacity for its core customers. A tying arrangement would remove the flexibility that core aggregators now enjoy to purchase gas either in the supply basin, at the California border, or at the PG&E citygate. SPURR/ABAG contend that the tying arrangement would violate FERC's capacity release rules, which provides that a holder of firm interstate capacity may not time the release of that capacity to any requirement or condition that is unrelated to the interstate capacity. PG&E's proposal to link the assignment of PG&E's interstate capacity with the assignment of PG&E's backbone capacity would accomplish exactly what the FERC rules prohibit. The Commission should reject PG&E's attempt to rebundle the intrastate (backbone) and interstate capacity options that are available to core aggregation customers.

A core aggregation customer's ability to acquire capacity on one pipeline or another, or on one path or another, is a matter of choice and flexibility. The core aggregation customer, like any noncore customer, should have the option to purchase its gas in the supply basin, at the US-Canadian border, at the California border, or at the PG&E citygate. This gas supply flexibility is at the heart of the Gas Accord. Under PG&E's proposal, a core aggregation customer would be forced to purchase its gas supplies either at the PG&E citygate (declining any assignment of capacity) or in the supply basin (accepting an assignment of capacity on the entire pipeline path). If PG&E's proposal is adopted, it would severely limit the flexibility that core aggregation customers currently enjoy under the Gas Accord.

Although PG&E asserts that the bundled capacity assignment would reduce gaming by core aggregators, and reduce costs to PG&E's core bundled customers, SPURR/ABAG assert that the acquisition of PG&E's reserved core capacity by core aggregation customers is not gaming. SPURR/ABAG assert that PG&E presented no evidence to demonstrate the need for a change in the core aggregation rules, and there is no evidence to suggest that the current unbundled capacity assignment procedure has resulted in gaming by core aggregators. Also, contrary to PG&E's assertion, there is no evidence that the unbundling of core aggregators' pipeline capacity has imposed additional costs upon core bundled sales customers.

SPURR/ABAG Power does not object to the other core aggregation proposals of PG&E. They have no objection to PG&E's proposal to make core aggregation customers subject to the same reliability standards that are imposed upon PG&E's bundled core procurement customers; the proposal for minimum storage inventory limits for all core procurement groups, including core aggregation groups; and PG&E's proposal to impose a mandatory assignment of transportation capacity and storage once the core aggregation program exceeds ten percent of the core market.

TURN expressed the view that the Commission should not address in this proceeding PG&E's proposal to offer an assignment of a pro rata share of its reserved core capacity on the ANG and NOVA pipelines to gas ESPs. SPURR/ABAG contend that this issue is ripe for consideration in this proposal. In TURN's response to the petition for modification of D.97-12-032 that was filed by SPURR/ABAG, TURN stated that to the extent that SPURR/ABAG believe that changes should be made to the capacity assignment rules as they apply to the core aggregation program, those changes should only be considered for the period following the expiration of the Gas Accord, which is what PG&E has done.

SPURR/ABAG in Exhibit 36 explained the mismatch between the firm capacity on ANG and NOVA and on the PGT pipelines. PG&E currently holds less firm capacity rights on the ANG and NOVA pipelines (591 and 593 MDth/day, respectively) than it holds on the PGT pipeline (610 MDth/d). Under the terms of the Gas Accord, the way this mismatch is treated is that PG&E reserves all of the ANG and NOVA capacity for its bundled core sales customers, and core aggregation customers do not receive an optional assignment of any of PG&E's ANG and NOVA capacity.

The Gas Accord provides that core aggregation customers will only receive an optional assignment of a proportionate share of PG&E's ANG and NOVA capacity when the amount of ANG and NOVA capacity that is available to PG&E's core bundled sales customers matches the amount of PG&T capacity that is available to PG&E's core bundled sales customers. That is, the core aggregation program must grow to the point at which core aggregation customer have the option to subscribe to more than 20 MDth/day of PG&E's reserved core PGT capacity, before the mismatch is eliminated, and core aggregation customers may receive a proportionate share of ANG and NOVA capacity.

Under the current terms of the Gas Accord, the core aggregation program must grow to approximately 7.6% of PG&E's core load before PG&E will make ANG and NOVA capacity available for assignment to core aggregation customers. As PG&E noted in Exhibit 1 at 16-3, the core aggregation program is only approximately 4% of PG&E's core load.

SPURR/ABAG supports PG&E's proposal to offer a pro rata share of PG&E's reserved ANG and NOVA capacity to core aggregation customers, but is not in favor of the bundling of the entire path. SPURR/ABAG contend that PG&E acquired and holds its ANG and NOVA capacity for all core customers, including both core bundled sales customers and core aggregation customers. Core aggregation customers receive an optional assignment of a proportionate share of capacity on every other pipeline (backbone and interstate) on which PG&E reserves capacity for the core market. SPURR/ABAG contend that core aggregation customers should have access to a proportionate share of the transportation capacity on the same pipelines over which PG&E serves its core bundled sales market. Core aggregation customers should not be denied access to PG&E's ANG and NOVA capacity simply because they purchase their gas supplies from a third party.

SPURR/ABAG assert that the mismatch of capacity is not related to the core aggregation program. As long as a core aggregation customer pays the full as-billed rate for the capacity, SPURR/ABAG contend that a core aggregation customer should be granted an optional assignment of an amount up to a proportionate share of PG&E's reserved ANG and NOVA capacity.

SPURR/ABAG also support PG&E's proposal to make available to core aggregation customers, a proportionate share of PG&E's newly acquired El Paso pipeline capacity (204 MDth/day), and a proportionate share of PG&E's reserved Transwestern pipeline capacity (150 MDth/d). PG&E has proposed in R.02-06-041 that this capacity should be reserved by PG&E for its core market. In order to compete with PG&E for sales of gas to core customers, core aggregators must have access to the same interstate and intrastate capacity to which PG&E's core procurement group has access. If the Commission decides in R.02-06-041 that this interstate capacity should be allocated to PG&E's core procurement customers, core aggregators should enjoy equivalent access to this capacity.

SPURR/ABAG also sponsored testimony with respect to the competitiveness of the gas supply options that are available to PG&E's core gas customers. Among PG&E's core customers, only four percent currently select core aggregation service. SPURR/ABAG contend that this low level of core customer participation in the core aggregation program strongly suggests that core customers are not fully aware of available competitive supply options.

SPURR/ABAG Power proposes that PG&E be required to explain how it prices its gas sales to core customers. In addition, PG&E must be required to explain the principles that underlie its gas price calculation. SPURR/ABAG

Power contend that without a clear explanation, the absence of a transparent core gas pricing mechanism inhibits the development of a competitive gas supply market.

PG&E stated in its opening brief at page 107 that it already provides extensive information about its core price. SPURR/ABAG contend that although PG&E provides the math to calculate the core gas price, it does not explain to its core customers the manner in which PG&E purchases gas (*i.e.*, a combination of long-term and short-term contracts), the manner by which PG&E uses storage for its core supply portfolio, or the method that PG&E uses to defer certain core procurement costs from one month to the next. In order for core customers to understand their gas purchase options, PG&E must provide a clear explanation of how PG&E purchases and prices its core portfolio gas on a monthly basis.

2. TURN

PG&E proposes to assign a pro rata share of its core Canadian pipeline capacity on the ANG and NOVA systems to gas ESPs. TURN points out that the Commission recently rejected a similar proposal in a petition for modification of D.97-12-032, which was denied on January 23, 2002. TURN asserts that there is no basis for inserting this issue into this proceeding.

3. PG&E

PG&E contends that the basic structure and rules for core aggregation have worked well for core customers under the Gas Accord structure. A functioning system is in place in which all core customers have a choice of supplier, which allows them to choose a gas supplier which best fits their needs.

PG&E contends that the changes to the CAT program will support system reliability, improve gas basin access for gas ESPs, and improve the allocation of cost responsibility for the core gas choice program. PG&E contends that its proposal strikes a reasonable balance between the desire of gas ESPs to have access to Canadian capacity, and concerns that the current flexibility in capacity allocation provides an excessive subsidy to gas ESPs and / or their customers.

SPURR / ABAG oppose PG&E's proposal that a core aggregation customer must accept the assignment of capacity on an entire path on a bundled basis, rather than accepting a separate assignment for each pipeline segment. SPURR contends that this amounts to an unreasonable tying arrangement in violation of the FERC capacity release rules. PG&E asserts that there is nothing unreasonable or unlawful about this proposal.

PG&E contends that the sole issue involves the core aggregation program and the Commission's rules under which PG&E will be permitted to assign some of its capacity holdings to gas ESPs. As such, the Commission has broad authority to administer and establish rules for the core aggregation program. Limiting the assignment of capacity to an entire path reduces gaming by gas ESPs, and gives the ESPs the option to better align their capacity holdings with the capacity held by PG&E on behalf of other core customers, simplifies the capacity assignment process, and reduces administrative inefficiencies.

PG&E also asserts that its proposal is not an unlawful tying arrangement. PG&E's Core Procurement Department, is one of many holders of capacity on interstate pipelines, and does not possess market power in the tying product. Core aggregators are free to purchase pipeline capacity, whether bundled or unbundled, from other firm capacity holders and marketers of capacity. Even if antitrust principles were implicated, PG&E's proposal merely involves the rules for a regulatory program that is under the Commission's control. So long as the program is based on a clearly articulated state policy and actively supervised by the state, it is immune from antitrust claims under the state action immunity doctrine.

SPURR/ABAG also argue that PG&E's annual assignment proposal places an unreasonable burden on ESP customers. PG&E points out that SPURR/ABAG fail to acknowledge that under PG&E's proposal, ESPs have the option, not the obligation, to take the capacity on an annual basis. Under PG&E's proposal, ESPs still would have an advantage over bundled core customers, since bundled customers don't have the option to accept or reject the costs of the transportation.

TURN contends that the Commission recently rejected making Canadian capacity available to gas ESPs, and that this issue should not be included in this proceeding. PG&E disagrees, and asserts that this is the correct forum in which to address this issue, and is distinguishable from the issue that was addressed in D.97-12-032.

SPURR/ABAG recommend that PG&E be required to publish additional information regarding the method and principles that pertain to computation of its monthly gas prices for core customers. PG&E contends that it already provides extensive information about its gas prices, including detailed workpapers that accompany each month's core gas rate filings, and that no additional information is needed. To the extent the information published by PG&E can be improved to further better service to its core customers, PG&E is willing to work with gas ESPs, and proposes to discuss that in the Core Procurement Advisory Group (CPAG) forum.

C. Discussion

1. Winter Firm Capacity Requirement Proposal

PG&E proposes that gas ESPs be subject to the same Winter Firm Capacity Requirement that is proposed for PG&E's Core Procurement Department. Such a requirement would mean that beginning in the winter of 2004-2005, all CPGs must hold sufficient firm intrastate pipeline capacity and storage capacity to meet its core demand for a 1-in-10 year cold temperature event. In order to meet this requirement PG&E proposes that all gas ESPs be given an option to take a pro rata share of PG&E's core holdings.

As discussed earlier, we are not adopting, at this time, PG&E's proposals for a Winter Reliability Standard and Winter Firm Capacity Requirement. Since the Winter Firm Capacity Requirement is not adopted, PG&E's proposal that gas ESPs be required to meet this requirement is moot.

As discussed below, gas ESPs will continue to have the right to obtain pro rata shares of transportation and storage capacity in 2004 and 2005.

2. Transportation Capacity Proposal

PG&E's second proposal is to offer to each gas ESP an annual option to a pro rata share of each of the four core transport paths.

Under the Gas Accord structure, gas ESPs have the option to accept or reject on a monthly basis a portion of PG&E's interstate and intrastate capacity holdings that serve core customers. (73 CPUC2d 829-830.) At the present time, these rights are offered on GTN, Redwood, and Baja. The gas ESPs' right to a proportionate share of the core rights on the ANG and NOVA pipelines are not triggered until certain conditions have been met. (73 CPUC2d 829.)

PG&E's proposal would change the current method in which gas ESPs can obtain a proportionate share of PG&E's Core Procurement Department's core transmission capacity. PG&E's proposal would change the monthly option to a yearly option. The proposal would also change which pipeline segments the gas ESPs could accept or reject, while broadening which pipeline paths would be made available to gas ESPs.

SPURR/ABAG is concerned that these changes will reduce the flexibility and choices that gas ESPs have. Instead of being allowed to decide whether to take a share of core capacity on a monthly basis, they will have to make an annual election for four set core transport paths.

One of the key features of the Gas Accord structure was to unbundle PG&E's gas transmission system into separate services. (73 CPUC2d 769, 771, 797.) PG&E's core transport paths, instead of unbundling the various ways in which gas ESPs can obtain gas, would require them to take service over the entire transport path. Instead of improving "flexibility and customer choice,"[103] the proposal that gas ESPs be required to take transmission service from the gas producing basins to the citygate over a fixed path restricts the manner in which gas ESPs can procure their gas supplies. Although the core transport path may make the administration of capacity assignments easier, and match upstream and downstream capacity, these administrative burdens are outweighed by the benefits of allowing gas ESPs the flexibility to decide where to purchase their gas, and how to transport it.

PG&E asserts that allowing gas ESPs to take or reject transmission service over pipeline segments has led to gaming. However, PG&E has not

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103 *See* 73 CPUC2d at 771.

demonstrated that the monthly option of allowing gas ESPs to decide which pipeline segment to take service on has resulted in adverse effects.

An annual election, as opposed to the current monthly election, also reduces the operating flexibility that gas ESPs have because it requires them to make an annual commitment for capacity. Although such a change could reduce the monthly excess capacity that may result if gas ESPs decide to reject capacity, the monthly option allows the gas ESPs more flexibility to meet their customers' needs.

Instead of expanding the choices available to gas ESPs, the annual election and core transport paths restrict the operational abilities of the gas ESPs. PG&E's transportation capacity proposal for gas ESPs is rejected.[104]

The rejection of PG&E's proposal leaves open the question of which paths gas ESPs can elect to have a proportionate share. The GTN, Redwood and Baja paths, still have reserved firm core capacity.

In Phase II of the El Paso proceeding in R.02-06-041, PG&E has proposed that its El Paso capacity serve core customers. PG&E proposes that to the extent that El Paso capacity is included in the CPIM, this capacity be made available to the gas ESPs. As referenced at pages 16-8 and 16-11 of Exhibit 1, "PG&E's existing Transwestern holdings" may also be available to the core.

The Canadian paths of NOVA and ANG are currently not offered to gas ESPs. Although PG&E's proposal would have made these two paths available as part of the Canadian core transport path, we have rejected PG&E's proposal. TURN points out that in A.96-09-028, the Commission rejected a petition to

[104] Since we are rejecting PG&E's proposal, there is no need to address the tying arrangement argument.

modify D.97-12-032 to make the NOVA and ANG paths available to gas ESPs. This occurred on January 23, 2002, when the Commission rejected a draft decision which would have granted the gas ESPs access to these pipelines. (*See* 1/23/02 Commission Agenda Results.) The Gas Accord also restricted gas ESPs from obtaining a proportionate share of NOVA and ANG until certain conditions were met.

We will continue to allow gas ESPs serving core customers to obtain a proportionate share of core holdings on the GTN, Redwood, and Baja pipelines. In the event the El Paso capacity, and possibly Transwestern capacity, is assigned to the core, and is included as part of PG&E's CPIM, we shall permit gas ESPs to obtain a proportionate share of those core holdings. Based on the Commission's January 23, 2002 action, and the Gas Accord's precondition to NOVA and ANG capacity, we will not allow gas ESPs to obtain a proportionate share of those two pipelines at this time.

3. Core Firm Storage Proposal

PG&E proposes to continue offering gas ESPs storage rights. Under the Gas Accord structure, as changed by the Comprehensive Gas OII Settlement Agreement, gas ESPs are offered a pro rata share of the total core firm storage rights. (D.00-05-049, Att. A, p. 15; *See* 73 CPUC2d 830.)

As described earlier, PG&E proposes to make five changes to the core storage program as set forth in Attachment A of D.00-05-049. Two of the changes are related to the Winter Firm Capacity Requirement, and how storage allocations are calculated, and the minimum monthly amount of gas that must be held in storage. The other changes affect the adjustment of inventory process, how rejected capacity is to be treated (discussed earlier), and PG&E's proposed Schedule G-CFS (discussed earlier).

SPURR/ABAG does not oppose PG&E's proposed changes.

We will permit PG&E to change the adjustment of inventory process. The change to the treatment of rejected capacity and Schedule CFS have been discussed earlier. Since we do not adopt PG&E's Winter Reliability Standard and Winter Firm Capacity Requirement, the two changes related to the Winter Firm Capacity Requirement shall not be permitted. PG&E's core firm storage proposal shall be adopted as changed by this discussion.

For 2004 and 2005, the core firm storage provisions shall be based on D.00-05-049 and the adopted core firm storage changes.

4. Core Aggregation Growth Proposal

PG&E's proposed core aggregation growth proposal is designed to address the issue of cost recovery of core transmission and storage holdings. Presently, gas ESPs serving core customers can reject or accept a pro rata share of these facilities. If gas ESPs are allowed to reject these facilities as they serve more customers, remaining customers will bear these costs.

SPURR/ABAG do not oppose this proposal. We will adopt PG&E's proposal to make it mandatory for gas ESPs serving core customers to accept a pro rata share of core transmission and storage capacity once the CAT program serves ten percent of peak core loads.

5. Information Proposal

SPURR/ABAG propose that PG&E be required to publish information about how PG&E computes its monthly gas price for core customers, and the principles behind the calculation. PG&E opposes the proposal because it already provides that kind of information in its monthly core gas filings, on customers' bills, and on its website. PG&E has also indicated a willingness to discuss this issue with the Core Procurement Advisory Group, of which SPURR is a member.

We do not adopt the proposal of SPURR / ABAG for PG&E to provide information regarding its monthly gas price. That kind of information already appears on customers' bills, and the detailed backup information is provided for in monthly filings and workpapers.

XVII. Interconnection Services

A. Proposals

1. Gas Rule 27 Proposal

PG&E's first interconnection proposal is to establish a new rule, "Gas Rule 27 – Gas Transmission Facilities Connections." This new rule would address the interconnection of electric generation facilities and other large noncore customers who request service from PG&E's gas transmission system. PG&E's second interconnection proposal is to offer a new tariffed service to off-system end users who want to directly connect to PG&E's backbone facilities.

PG&E is proposing Gas Rule 27 to address the needs of large gas customers who require transmission-level service. Rule 27 would apply to transmission-level customers who are served under the following existing gas rate schedules: Schedule G-EG – Gas Transportation Service to Electric Generation; Schedule G-COG – Gas Transportation Service to Cogeneration Facilities; and Schedule G-NT – Gas Transportation Service to Noncore End-Use Customers.[105] Rule 27 allows for revenue-based allowances, while ensuring recovery of costs for both reinforcements of PG&E's existing system and the extension of new facilities, through local transmission and customer access charges revenue generated by customers.

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[105] PG&E is proposing a single electric generation class in Schedule G-EG, which would serve all electric generation. If this class is created, Schedule G-EG would serve those customers who currently take service under existing Rate Schedules G-EG and G-COG.

PG&E contends that Rule 27 is needed because Gas Rule 15,[106] which is the only PG&E tariff applicable to gas transmission interconnections, primarily applies to distribution-level interconnections at pipe pressures less than 60 pounds per square inch, and contemplates transmission-level interconnections at PG&E's convenience. PG&E states that distribution-level facilities are rarely of sufficient capacity to serve large customers. Rule 15 also limits the allowances towards investments made by PG&E to extend transmission facilities to serve new customers. Since transmission-level customers currently pay for the majority of costs associated with any transmission-level extension, Rule 15 creates an obstacle to the citing of electric generation, as well as other noncore load. The revenue credit proposed in Rule 27 would replace the relatively small distribution-based revenue allowance in Rule 15.

If Rule 27 is not adopted, PG&E would have to file an advice letter for an extension of service as an exceptional case,[107] under the provisions of Gas Rules 15 and 16,[108] each time transmission-level service is sought. Such a filing would be necessary in most instances because the costs of connecting these large customers exceed the local transmission and customer access charges revenues. If Rule 27 is adopted, it will eliminate most of the exceptional case advice letter filings because the guidelines are contained in Rule 27.

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106 Rule 15 is entitled "Gas Main Extensions."

107 An exceptional case filing within the context of interconnections under PG&E's gas rules refers to a project that does not quite fit the terms and conditions of the provisions of the rule, and the applicant and PG&E may want to change some of the terms and conditions or provisions of the rule to better fit that interconnection. (R.T. 345.)

108 Gas Rule 16 is entitled "Gas Service Extensions."

Some of the parties propose that the language of Rule 27 be clarified in certain respects, and that connecting customers be provided with additional financial incentives.

2. Off-System Direct Connect Proposal

The purpose behind PG&E's proposal for a new tariffed service to directly connect off-system customers to the backbone is to attract users who are interested in using PG&E's transmission service as an alternative to using interstate pipelines, a private pipeline accessing California gas production, or an alternative fuel source. This interest has occurred along the Baja path (Line 300) and near the terminus of Line 401. By allowing these end users to connect to the backbone, they will have added supply options, including California and Canadian gas sources, as well as improved service reliability.

In D.94-12-061 (58 CPUC2d 440), PG&E was authorized to offer off-system direct connect service on Line 401. However, this off-system direct connect service does not apply to the rest of PG&E's backbone facilities, and a Line 401 direct connect request requires the filing of an application under the Expedited Direct Connection Docket (EDCD) for each customer.

PG&E's proposal seeks to allow off-system end users to directly connect to PG&E's transmission facilities if they meet two eligibility requirements, which are described at page 18-7 of Exhibit 1, and in the discussion portion of this section. PG&E also proposes to allow the off-system direct connect customers to take other PG&E services, such as monthly balancing, subject to the specific terms and conditions of those services. The off-system direct connect customers will be required to sign an agreement specifying the terms of service, and a customer-specific monthly interconnection charge will be developed and assessed based on the ongoing costs to maintain the meter and interconnection.

B. Position of the Parties

1. CCC/Calpine

Overall, CCC/Calpine support Rule 27. However, CCC/Calpine believe that Rule 27 should be modified to better account for the benefits that PG&E and its customers incur as the result of facilities built on behalf of a particular customer. Rather than requiring the customer to pay the entire estimated contribution in all instances, as proposed Rule 27 would do, CCC/Calpine propose that PG&E share the risk of new interconnections by waiving the unrecovered balance if the customer is able to reduce that balance to meet any of the following milestones: (1) 50% within 3 years; (2) 65% within 5 years; (3) 75% within 7 years. CCC/Calpine assert that that customers that meet these proposed milestones will have demonstrated their viability and the likelihood that PG&E will recover its margin.

CCC/Calpine also propose that Rule 27 be amended to give the interconnecting customer credit for the full costs PG&E avoids by having incremental capacity made available, and to provide for refunds if additional new customers take service from the facility. PG&E should pay for, or credit the customer for, the full costs that PG&E avoids as a result of the interconnection. PG&E's proposal to pay only the incremental cost of these additions is not appropriate.

In order to properly reflect the benefits that can be created by new interconnections, CCC/Calpine suggest that Rule 27 be modified to include a provision similar to Rule 15.E. Rule 15.E provides a customer with a refund of one's contribution to a distribution main addition if additional new customers take service from that main. Adding such a provision ensures that interconnecting customers are not required to subsidize improvements enjoyed by other customers.

CCC/Calpine also propose that backbone rate revenue be included in the calculation of customer contributions toward meeting Rule 27's economic benefit test. Customers contribute to net margin to PG&E through the payment of backbone rates. Under the economic benefit test of Rule 27, only revenues from local transmission and customer access charges are considered.

PG&E contends that customers seeking connections to high-pressure facilities should be treated as Special Facilities under Rule 2, rather than under Rule 27. PG&E asserts that high-pressure facilities are a special benefit to the requesting customer that does not benefit the system at large. CCC/Calpine contend that the reality is that new gas turbine generators require high-pressure gas service, and a substantial portion of the costs of interconnections with new electric generation facilities is often the cost of providing higher-pressure service. To recognize the realities of electric generation, Rule 27 should be amended to include within a transmission facility connection, the cost of facilities to provide higher delivery pressures.

CCC/Calpine point out that proposed Rule 27.A.1.d provides that PG&E will not be required to connect with any non-PG&E pipelines. CCC/Calpine contend that in some cases, the most cost-effective way for a new generator to be served is to interconnect with a private or municipal pipeline that is or can be connected to PG&E's system. Rule 27 should not prevent customers from seeking the most cost-effective method of obtaining gas for electric generation.

Given the significant reservations about how the rule will work and its potential impact on customers, CCC/Calpine believe that it may be appropriate to defer consideration of the rule until workshops on the rule have been held.

2. Duke

Duke believes that Rule 27 is acceptable so long as PG&E clarifies that an applicant for new service will be charged only for the costs relevant to its service connection, and any additional costs associated with sizing the connection for future loads be borne by the utility.

3. LGS

LGS expressed concern about the language in proposed Rule 27.A.1.d which states: "PG&E shall not be required to serve any Applicant from transmission facilities, or any other gas pipeline facilities not owned, operated, and maintained by PG&E." That language could allow PG&E to refuse to transport gas withdrawn from storage by customers of independent storage providers and delivered via their ancillary pipelines to PG&E's transmission system. When PG&E witness Haley testified, he clarified that PG&E does not intend to prevent third-party storage providers from serving their customers via third party storage pipelines that interconnect with PG&E's system, and would work with parties to remove any ambiguities in proposed Rule 27.

LGS suggests that the Commission should be clear in any decision approving the Rule 27 proposal, that PG&E must clarify the language of the rule so that the rule has no impact on the delivery of gas to PG&E's system for third party storage. If Rule 27 is approved, the Commission should order the parties to work together to clarify the language.

4. Mirant

Mirant is concerned that Rule 27 places a disproportionate share of the cost of additions to serve other customers that come after the initial interconnection, on the interconnecting customer. Mirant believes that a more equitable assignment would be to assign the new customer a share of the costs proportional to the new customer's average use of the new system capacity.

Although PG&E proposes tariff language in Rule 27 to shield the interconnecting customer from having to bear the costs of separate or incremental facilities included in the interconnection project to serve other customers, this language does not address the concern of Mirant about the unfairness of the incremental cost assignment approach. PG&E's incremental approach assigns a share of costs to the interconnecting customer significantly in excess of that customer's share of prospective benefits. Mirant recommends that the Commission require PG&E to amend Rule 27 to give effect either to Mirant's proposal that new customers be assigned a share of costs proportional to the new customer's average use of the new system capacity, or the suggestion of CCC/Calpine that the interconnecting customer be given credit for the full costs PG&E avoids by having incremental capacity made available.

Mirant is also concerned about PG&E's discussion of risk allocation issues. PG&E proposes that Rule 27 apply to system reinforcements, as well as service extensions. PG&E witness Haley testified that Rule 15 uses a standard form agreement that includes a provision attesting that the customer's load justifies the reinforcement work involved, and that should the applicant's load not develop as intended, that PG&E reserves the right to collect the cost of reinforcements that turn out not be necessary. Under Rule 15, the customer is off the hook if the project load is achieved, even if revenues are disappointing. However, under Rule 27, the customer is obligated to pay all of the costs of the reinforcement if the anticipated customer revenue from customer access and local transmission charges do not reach the projected level. Mirant asserts that this distinction is important because it supports the position of CCC/Calpine to waive the unrecovered balance if a sufficient proportion of anticipated revenue is achieved, for providing refunds if additional new customers take service from a new facility, and for including backbone rate revenue in the calculation of customer contributions.

5. NCGC

NCGC points out that under proposed Rule 27, if PG&E's cost of constructing the connection or reinforcement cannot be supported by the forecasted local transmission and customer access charge revenues, the customer will be required to pay the difference.

NCGC asserts that the Rule 27 proposal is outside the scope of this proceeding. In addition, due to the slowdown in the construction of new electric generation plants, the rule is currently not necessary. NCGC also notes that connections and reinforcements have been installed in the past without Rule 27. NCGC recommends that PG&E's Rule 27 proposal be dismissed without prejudice, and that the issues regarding Rule 27 be resolved in a workshop.

If the Commission decides to adopt Rule 27, NCGC recommends that we revise proposed Rule 27 as recommended by CCC / Calpine and Mirant so that PG&E bears at least some of the risk of the new interconnection costs.

CCC / Calpine and Mirant also recommend other changes to Rule 27. These changes include the following: include a provision that parallels Rule 15.E to permit a customer to get a refund for the customer's contribution to a capacity addition if additional new customers take service from the new capacity; provide for an interconnecting customer to receive a credit based on the full costs that PG&E avoids as a result of installing an interconnection facility, not just the incremental cost; that the economic benefit test in Rule 27 be modified to recognize backbone revenues that result from interconnecting with a new customer, as well as local transmission revenues; and that Rule 27 be changed to include the cost of facilities that are needed to provide higher delivery pressures rather than continuing to treat such facilities as special facilities under Rule 2. NCGC supports all of these proposals.

6. ORA

ORA states that the ratepayer impacts of PG&E's proposed Rule 27 could not be properly reviewed and assessed within the time allotted, and that such a proposal should be deferred to a later proceeding.

7. SMUD

If the Commission does not adopt the proposal for a backbone level rate, or does not adopt a higher load factor, Rule 27 should be changed to allow SMUD to credit some or all of its costs of constructing the SMUD gas pipeline system against PG&E's local transmission rates. SMUD contends this is proper because of the cost savings that PG&E's customers received as a result of SMUD building its own pipeline system to serve its gas-fired plants.

8. PG&E

CCC / Calpine and others suggest that a new customer should only have to pay for system reinforcements net of system benefits, and that Rule 27 does not result in an equitable share of system upgrade costs. PG&E asserts that its proposed Rule 27 provides for an equitable allocation of system upgrade costs between the applicant and PG&E. When an applicant applies for service, PG&E's practice is to allocate only the costs of the applicant's interconnection to the applicant. But for the Rule 27 applicant, PG&E would not be making the interconnection. PG&E does not propose to deviate from that practice in proposed Gas Rule 27. If additional facilities are added by PG&E in conjunction with the upgrades required for an applicant, PG&E will pay those incremental costs. According to PG&E's witness Haley, although proposed Rule 27 tariff does not specify that the incremental costs would be at PG&E's expense, such language could be added to clarify the intent of Rule 27.

CCC / Calpine suggest modifying proposed Gas Rule 27 to allow for refunds to reduce a customer's "Unrecovered Balance" if additional customers take service from the interconnection facilities that PG&E installed for the applicant. PG&E recommends that this proposal be rejected as unrealistic. Based on the classification of customers that are covered by proposed Gas Rule 27, PG&E contends it is unlikely that another transmission-level customer will be able to be served from the pipe that PG&E installed to serve the applicant without additional reinforcement. In addition, tracking the other load would be cumbersome, and customers would gain little or no benefit. If sufficient excess capacity exists to accommodate other customers, that incremental capacity would be provided at PG&E's expense.

CCC / Calpine advocate changing Rule 27 to include, within a Transmission Facilities Connection, the cost of facilities to provide higher delivery pressure. PG&E is opposed to this suggestion. PG&E points out that facilities which are of special benefit to a single customer should continue to be treated as Special Facilities under Gas Rule 2, and that other ratepayers should not be expected to subsidize such facilities. Rule 2 only applies to the incremental cost increase between the volumetric design and the applicant's specific request for additional elevated pressure. To the extent special facilities are constructed, these costs are not eligible for revenue-based allowances under proposed Rule 27. PG&E's experience also shows that applicants generally select the option that provides them with the most economical delivery of elevated pressure. Instead of asking PG&E for additional elevated delivery pressure in excess of the prevailing transmission pressure already provided by PG&E in the volumetric design, the applicant may choose the option of installing compression equipment on their side of the meter to accommodate the pressure their equipment requires.

Proposed Rule 27 allows the applicant two options for connecting to PG&E's transmission system: (1) through PG&E-owned and maintained facilities from the interconnection point with PG&E gas transmission facilities to the service termination point, typically at the applicant's facility; or (2) by connecting to facilities the applicant builds, owns, and maintains, from their facility to PG&E's transmission facilities. SMUD recommends changing Rule 27 to allow for PG&E revenue credits against SMUD's costs of constructing its own gas pipeline interconnections with PG&E.

PG&E recommends that SMUD's proposal not be adopted. SMUD should not be given a PG&E revenue credit, when for a variety of business reasons, the party chooses to build, own and maintain its own pipeline facility. PG&E contends that providing such a credit would require remaining ratepayers to unfairly subsidize private ventures. The remaining ratepayers should not be held captive to pay for facilities that are not owned, operated, and maintained by the utility.

CCC / Calpine propose that the remaining Unrecovered Balance be waived if the customer is able to reduce the balance according to certain milestones. PG&E contends it should not be required to waive its right to collect the Unrecovered Balance for investments whose expected average service life for new transmission mains is 45 years. PG&E asserts that it is already assuming a certain level of risk under Rule 27, which limits the cost recovery guarantee period from the new customer to only ten years.

CCC / Calpine suggest that the credits against the Unrecovered Balance include contributions to the backbone and customer access charges, and that the contract that a customer executes under proposed Rule 27 be for backbone level service. PG&E asserts that proposed Rule 27 already adequately and reasonably handles this situation. PG&E points out that proposed Rule 27 contemplates and accommodates interconnections from all of PG&E's transmission systems, and it is highly unlikely that an individual generation facility will cause a need for reinforcements to the backbone. In the event that backbone reinforcement is required, PG&E and the applicant would likely need to negotiate a special agreement to allocate the costs of such reinforcement. Proposed Rule 27.E.3. allows for this possibility by providing a method for filing an exception to the tariff with the Commission for approval.

Where there are connections to the backbone, PG&E will still credit local transmission and CAC paid by the customer against the costs of the interconnection, and in the form of a contract developed for use with proposed Rule 27. PG&E contends that these credits reflect a reasonable and adequate amount of credit against the costs of the interconnections.

CCC / Calpine propose that backbone revenues be included in the customer credit. PG&E states this proposal should be rejected because the backbone capacity may not be held by an end-user, making it impossible to attribute revenues to that customer. Also, as new more efficient gas-fired electric generation is brought on line, it is likely it will displace older, less efficient generating facilities. Thus, the amount of backbone revenue attributed to the new facility may not be incremental, but actually decremental. Also PG&E has the obligation to serve, and it assumes the risk for costs associated with facilities not supported by revenue.

CCC/Calpine and Mirant object to proposed Gas Rule 27 because it removes from the utility any risk that PG&E will fail to recover the costs of its interconnection with a new electric generation customer. They contend that under Rule 15, PG&E has always borne some of the risk that a new distribution-level customer will remain on the PG&E system long enough to pay off its interconnection costs.

PG&E contends that CCC/Calpine and Mirant mischaracterize the risk allocation between the customer and PG&E, and Rule 15 and proposed Rule 27. PG&E asserts that the risk allocation methodology is the same under Rule 15 and Rule 27. To the extent the applicant generates revenue, PG&E credits that for both new and reinforced facilities. Under both rules, at the end of 10 years, if the customer does not generate the revenue sufficient to cover the costs of facilities, the customer is liable for the balance between the costs of the interconnection and the revenue generated. PG&E asserts that it would be inequitable to encumber the remaining ratepayers with the risk that an individual customer would generate enough revenue to support the costs of such interconnection, while allowing the customer to be the sole recipient of any reward if it does not. As long as PG&E has an obligation to serve, it is reasonable to expect its investments to be supported by revenue.

CCC/Calpine witness Beach asserts that Rule 27 does not require PG&E to serve any pipelines that are not maintained or owned by PG&E, and that it allows only one pipeline to pipeline interconnection. Beach proposes that Gas Rule 27 be modified to allow for multiple interconnections with private pipelines. PG&E points out that under its proposed Gas Rule 27, PG&E would not be required to serve an applicant via a third-party owned section of pipe inserted between PG&E's interconnection point and its meter. The proposed gas rule does not state, as Beach asserts, that PG&E should not be required to serve any pipelines that are not owned or maintained by PG&E.

PG&E points out that Rule 27 is not intended for pipeline-to-pipeline interconnections, where there is no retail end-use gas customers to be served. Instead, the rule is applicable to all connections for permanent transmission-level service to PG&E's gas transmission system serving facilities that qualify for service under Schedule G-EG or Schedule G-NT. PG&E should not be made to serve its customers from privately owned pipelines inserted between PG&E's interconnection point and its metering facilities.

PG&E also contends that proposed Rule 27 allows only one connection per facility. If an applicant requests multiple gas transmission services to a single generation facility, the first service would be installed under proposed Rule 27, and the second or additional services would be installed under Gas Rule 2. Thus, CCC's proposal to modify Rule 27 to allow for multiple interconnections should be denied.

NCGC has proposed that Rule 27 be addressed in workshops before it is adopted. PG&E opposes this, and asserts that the rule should be adopted now. Workshops have already been held, and NCGC participated in the workshops.

PG&E acknowledges that although the number of proposed gas-fired electric generation plants that could use Rule 27 has gone down, that number could grow again in the future. Without Rule 27 in place, PG&E will have to use a patchwork of exceptional case provisions under other gas rules to accommodate the new gas-fired electric generation plants.

C. Discussion

1. Gas Rule 27 Proposal

PG&E proposes the adoption of Gas Rule 27, which is set forth in Appendix 1 of Chapter 18 of Exhibit 1. Although PG&E held informal workshops to discuss the proposed rule with interested participants before the proposed tariff was submitted in this proceeding, as indicated in the positions of the parties, there are still a number of issues that the parties cannot agree upon.

PG&E and other parties have discussed a number of projects for interconnection at the transmission-level in recent years. PG&E witness Haley testified that during the last five years, there have been no exceptional case facilities agreements for transmission-level facilities. As of April 2003, there were approximately ten to fifteen requests for interconnection, several of which would fit more appropriately under Rule 27 rather than Rule 15. (RT 346-347.) This testimony is indicative of two things. First, that there has been a slowdown in new connections as a result of fewer gas-fired electric generation projects being pursued. Second, the projects that require interconnection to transmission-level service can or have used exceptional case agreements or the standard provisions of Gas Rules 2, 15 and 16.

Based on the issues that parties have with PG&E's proposed Rule 27, the reduction in the number of requests for transmission-level interconnections, and the existing ability to use exceptional case agreements or the standard provisions of Gas Rule 15 and others, there is no need to adopt PG&E's proposed Gas Rule 27 at this time.

2. Off-System Direct Connect Proposal

PG&E's second interconnection proposal is to establish a new tariffed service to allow eligible off-system end users to connect directly to PG&E's

backbone transmission service. In order to be eligible for this service, PG&E proposes that the end user meet both of the following tariff eligibility requirements:

> "1. The customer does or can take pipeline delivery service directly from an interstate pipeline, a private pipeline, or an alternative fuel source, and such service does not in any way depend on services being provided by another CPUC-regulated Local Distribution Company (LDC), even if the customer still maintains a connection to that utility's facilities. If the customer is a new customer and the interstate or private service connections do not currently exist, the customer must verify through a legal declaration that such connections would be made, and service would not be provided by a California LDC, absent a connection to PG&E's transmission system; and
>
> "2. The customer builds and is responsible for, maintaining the necessary facilities at the customer's cost to interconnect to the PG&E backbone transmission system, and to provide or pay for the meter set and other necessary special facilities charges. Connections to these customers will be done under the provisions of PG&E's Gas Rule 2, or another similar agreement." (Ex. 1, p. 18-7.)

Under PG&E's proposal, the off-system direct connect customer will be allowed to use other PG&E services, such as monthly balancing, subject to the specific terms and conditions of those services. The off-system direct connect customers will be required to sign an agreement specifying the terms of service. In addition, a customer-specific monthly interconnection charge will be developed and assessed based on the ongoing costs to maintain the meter and interconnection.

PG&E did not submit a sample tariff for its off-system direct connect proposal. No one objected to PG&E's second proposal, and no cross-examination on this proposal took place.

As the starting point for our analysis of this proposal, we turn to D.94-02-042 (53 CPUC2d 215) and D.94-12-061 (58 CPUC2d 440). In those decisions, we discussed the issue of direct connection to the Line 401 expansion project. In D.94-02-042, we prohibited the direct connection of customers to Line 401, except at Kern River Station. (53 CPUC2d at 245.) Petitions for modification of D.94-02-042 were filed, and the topic of direct connection was the subject of a workshop and comments in that Line 401 proceeding. (58 CPUC2d at 448.) In D.94-12-061, we authorized the direct connection to Line 401 where the customers' loads are incremental to current and future original system loads through the use of the EDCD application procedure. (58 CPUC2d at 443, 448.)

PG&E's off-system direct connect proposal must be clarified in two respects. The first clarification is that PG&E's proposal refers to an off-system customer being able to request a direct connection to "<u>any portion</u> of PG&E's transmission system." (Ex. 1, p. 18-7, emphasis added.) However, elsewhere in Chapter 18 of Exhibit 1, PG&E's proposal refers only to an off-system direct connect to PG&E's <u>backbone</u> transmission service. We clarify for the purposes of this decision that PG&E's proposal is only for off-system end users to directly connect to any portion of PG&E's <u>backbone</u> transmission system.

The second clarification is if this proposal is adopted, D.94-12-061 will be affected to some extent. Under D.94-12-061, both on-system and off-system users who want to directly connect to Line 401 must follow the EDCD procedure. If PG&E's tariff proposal is adopted, off-system end users who want to directly connect to any of PG&E's backbone facilities would no longer have to use the EDCD as provided for in D.94-12-061. (*See* 58 CPUC2d at 461, App., § 1. Eligibility.) However, new or existing loads located on-system, who seek to direct connect to PG&E's Line 401 at locations other than Kern River Station, will still be required to use the EDCD procedure. In addition, new or existing loads located on-system, who seek to direct connect to other PG&E backbone transmission lines other than Line 401 are prohibited from doing so unless another Commission decision has authorized such a connection.

In D.94-12-061, the criteria for approving a direct connection to Line 401 was developed. That criteria consists of the following: the connecting customer and its load is incremental under the definition in D.94-02-042, as further explained in D.94-12-061; the direct connection cannot displace present or future original system loads; and original system ratepayers must not lose the opportunity to serve future loads that would be served by PG&E's original system if Line 401 did not exist. Under PG&E's proposed eligibility requirements for this off-system direct connect service tariff, these criteria are met. Under the first eligibility requirement that PG&E proposes, the end user must or can be served from an interstate pipeline, a private pipeline, or an alternative fuel source, and such service cannot depend in any way on services provided by another Commission-regulated gas utility. Under the first eligibility requirement, the off-system end user's load is incremental because the other gas utility, which is most likely to be SoCalGas, must not be providing any of the services from which the off-system end user is receiving its natural gas or alternative fuel. In addition, this incremental load is not displacing any present or future loads, and original system ratepayers are not losing an opportunity to serve future load since the load is coming from off-system.

The second eligibility requirement that PG&E proposes ensures that the off-system end user must pay for the interconnection facilities, the meter set, and other necessary special facilities charges.

We authorize PG&E to file a tariff via an advice letter filing which offers off-system end users the ability to directly connect to all of PG&E's backbone transmission facilities. Such a tariff filing shall be consistent with the above discussion. End users who are within the service territory of PG&E who want to directly connect to Line 401 may continue to do so as provided for in D.94-02-042 and D.94-12-061.

XVIII. California Gas Transmission Risk Management Program

A. Summary

PG&E requests authority to continue the use of the existing Commission-approved California Gas Transmission (CGT) Risk Management Program beyond 2003. The program uses financial derivative instruments to manage the price and revenue risks associated with gas transmission and storage assets.

PG&E also proposes certain modifications to the program. The first modification is to increase the authorized derivative trading limit from $200 million to $400 million of the gross market value of the derivatives, and to increase the trading volume at any point in time from 800 MMcf/d to 1000 MMcf/d. PG&E asserts that the dollar limit is necessary to cover commodity prices and high price volatility as experienced during 2000 and 2001. The volume limit is needed to reflect the recent pipeline expansion of the Redwood path. PG&E notes that all of the gains and losses resulting from financial derivative trading activities will continue to be borne by PG&E's shareholders.

The second proposed modification to the CGT Risk Management Program is to reduce the restrictions on trading financial derivatives with certain customers. PG&E is currently restricted from trading financial derivatives with its customers or affiliates. PG&E requests that the restriction be applied only to retail customers, and that two non-retail exceptions be recognized and authorized. The first non-retail exception is for wholesale marketers, who are large, nationally recognized companies. PG&E contends that this group does not need to be protected against PG&E by restricting the trading of financial derivative instruments. The second non-retail exception is for marketing affiliates of PG&E's retail transportation and market storage customers. These retail customers include some of PG&E's largest end-users of gas, such as electric generators and oil refineries. Due to the current customer restrictions, PG&E has not been able to enter into financial derivative arrangements with these marketing affiliates, who are separate legal entities. PG&E requests that the customer restriction no longer apply to these marketing affiliates.

PG&E's third proposed modification is for the Commission to authorize the use of weather derivatives, electricity derivatives, and other derivatives developed by the financial market which many emerge as viable tools for CGT to manage its risk.

PG&E also requests elimination of the current sunset date of December 31, 2003, so that forward hedge positions can be entered into before 2004. PG&E contends that these modifications are needed to manage the price and revenue risks in the marketplace.

PG&E contends that the evidence supports continuing the CGT Risk Management Program with the proposed modifications for 2004 and beyond.

B. Discussion

No parties have expressed any opposition to PG&E's request to continue the CGT Risk Management Program, or to the proposed changes which it seeks.

The CGT Risk Management Program was first authorized in D.98-12-082 when we granted PG&E authority to use natural gas-based financial instruments to manage the price and revenue risks associated with its natural gas transmission and storage assets. This authority was modified in D.99-04-013. As part of the Gas Accord II Settlement Agreement adopted in D.02-08-070, the CGT Risk Management Program was extended through the Gas Accord II period.[109]

We have reviewed the three decisions which addressed the CGT Risk Management Program, and the reasons why certain conditions were imposed. Since a gas structure is being adopted in today's decision for 2004 and 2005, the CGT Risk Management Program should also be extended through December 31, 2005. This will allow PG&E to continue to manage the price and revenue risks associated with its natural gas transmission and storage assets.

As for PG&E's request to make three changes to the CGT Risk Management Program, the first change to increase the dollar limit and trading volume reflect conditions that now exist or have occurred in the past. That change will be adopted.

The second change is to change the restriction with whom PG&E can trade derivatives. Instead of restricting trading with retail customers and affiliates, PG&E seeks to restrict trading with retail customers only, and that two non-retail exceptions be recognized and authorized. The first non-retail exception is for wholesale marketers. The second non-retail exception is for marketing affiliates of PG&E's retail transportation and market storage customers. We have

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[109] The "Gas Accord II Period," as used in the Gas Accord II Settlement Agreement, refers to the period of January 1, 2003 to December 31, 2003 for gas transmission service,

Footnote continued on next page

considered the reasons why the restrictions on trading with retail customers and affiliates were originally imposed in D.98-12-082. We do not believe that changing the restriction to allow trading of financial derivatives with wholesale marketers and marketing affiliates of PG&E's retail transportation and storage customers will result in market power or anticompetitive impacts. Accordingly, the second change to the CGT Risk Management Program will be adopted.

The third change that PG&E requests is for the Commission to authorize the use of weather derivatives, electricity derivatives, and other derivatives that may be developed by the financial market to manage its risk. We will allow PG&E to use these additional derivatives. Since the quarterly reporting requirements remain in place, the reports will allow us to monitor the use of these additional derivatives. The third change to authorize PG&E to use these kinds of derivatives will be adopted.

PG&E also requests elimination of the current sunset date of December 31, 2003, so that forward hedge positions can be entered into before 2004. Since we are adopting a gas structure through 2005, the authority allowing PG&E to use derivatives should be extended as well. The authority granted in today's decision to allow PG&E to use derivatives shall expire on December 31, 2005.

PG&E is authorized to continue using financial derivative instruments to manage price and revenue risks pursuant to the CGT Risk Management Program that was approved in D.98-12-082, as modified in D.99-04-013, as extended by D.02-08-070, and as changed by today's decision. This authority for PG&E to use

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and the period of April 1, 2003 to March 31, 2004 for storage service. (D.02-08-070, App. A, p. 1.)

financial derivatives shall expire on December 31, 2005 unless further extended by the Commission.

XIX. Future Gas Market Structure and Rate Filings

Since this decision adopts a gas market structure for PG&E's transmission and storage systems for 2004 and 2005, and rates for 2004, we need to provide guidance to PG&E and the parties regarding future filings.

Rates for PG&E's gas transmission and storage systems are being set for 2004 only. Unlike the Gas Accord, no settlement has been proposed to set rates for a multi-year term beyond 2004. Therefore, rates for 2005 will need to be addressed in 2004. PG&E shall file an application proposing its 2005 gas transmission and storage rates on or before March 19, 2004. This date will provide sufficient time for PG&E, interested parties, and the Commission to address the 2005 rate proceeding before the end of 2004.

The gas market structure adopted in today's decision shall continue through 2005. Except as noted in this decision, we will not entertain proposals in the 2005 rate proceeding to change the gas market structure, and we will not entertain the proposals for a Winter Reliability Standard. All of these issues involve significant cost commitments, and policy considerations, which we are unwilling to consider given present circumstances. These issues, however, may be raised in PG&E's application to determine the gas market structure for 2006 and beyond and rates for 2006.

PG&E's application regarding its proposal for a gas market structure for 2006 and beyond, and gas transmission and storage rates for 2006, shall be filed on or before February 4, 2005. That application should also address whether it is more productive and efficient to conduct a review of PG&E's gas transmission and storage rates every two years, instead of on an annual basis.

XX. Conclusion

We adopt a gas market structure that is virtually the same as the Gas Accord structure that has been in place since March 1, 1998, and as changed by the other decisions mentioned in this decision. PG&E's transmission and storage systems shall be subject to the adopted gas market structure for 2004 and 2005. The adopted gas market structure balances the competing interests of the utility, wholesale and retail customers, shippers, and marketers.

This decision also adopts a revenue requirement of $436,397,000 for PG&E's gas transmission and storage system for 2004. The revenue requirement is based on the various proposals and adjustments adopted in today's decision.

PG&E shall file an advice letter containing its rate tariffs within five days of today's date. The tariffs shall be consistent with, and comply with the adopted revenue requirement, the adopted adjustments, the proposals adopted in this decision, and the cost allocation and rate design methods adopted in this decision. PG&E shall also operate its transmission and storage operations in accordance with today's decision.

The rate tariffs shall be reviewed by the Energy Division for compliance with this decision, and shall go into effect January 1, 2004. The rate tariffs are subject to protest, and such protests shall be filed within ten days after the advice letter has been filed. PG&E shall serve the advice letter seeking approval of such rate tariffs by e-mail and by mail to the service list to this proceeding. If a protest to the advice letter filing requesting the rate change is filed, the rate(s) shall remain in effect unless a Commission resolution or decision rescinds, suspends, or changes the rate(s).

XXI. Comments on Proposed Alternate Decision

The draft alternate decision of Commissioner Peevey in this matter was mailed to the parties in accordance with Rule 77.6 of Rules of Practice and Procedure on December 4, 2003. Comments were timely filed by Duke Energy North America, Pacific Gas and Electric, the Utility Reform Network, Department of General Services, Sacramento Municipal Utility District, Calpine, California Cogeneration Council, Northern California Generation Coalition, and the Office of Ratepayer Advocates.

The comments of the parties have been considered, and appropriate changes have been made to the decision.

XXII. Assignment of Proceeding

Loretta M. Lynch is the Assigned Commissioner, and John S. Wong is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The Gas Accord market structure was approved in D.97-08-055, modified in part in D.00-02-050 and D.00-05-049, and extended through 2003 in D.02-08-070.

2. The Gas Accord Settlement Agreement, attached to D.97-08-055 as Appendix B, describes more fully the market structure for PG&E.

3. PG&E's application proposes to retain the basic market structure of the Gas Accord, with certain proposed changes.

4. PG&E's gas transmission and storage systems are currently operated under the rules set forth in the decisions noted in Finding of Fact 1.

5. Since the Gas Accord structure and rates are to expire at the end of 2003, PG&E's application had to address the kind of market structure that should be adopted for 2004, and what rates should look like.

6. PG&E's application and its supporting testimony essentially amounted to a GRC for PG&E's gas transmission and storage system.

7. No one has proposed a different market structure for PG&E's gas transmission and storage system, and all of the parties use the existing Gas Accord structure as the basis of their market structure.

8. Extending the gas structure beyond 2004 will provide market participants with some certainty about what kind of structure will remain in place if the Commission retains jurisdiction over PG&E's gas transmission system.

9. The evidence regarding how the Gas Accord structure has performed since its inception, is relevant in deciding what kind of gas structure should be in place beyond 2004.

10. No one disagrees that the Gas Accord structure has brought many benefits to market participants in PG&E's service territory.

11. Unlike D.02-11-073, the central focus of this proceeding is to address the gas market structure for PG&E's gas transmission and storage systems, and to set rates for 2004.

12. PG&E provided little support to justify why a proceeding investigating a specific set of circumstances in Southern California should be applied equally to PG&E.

13. The planning and design of the size of the transmission facilities to serve customer load is not a gas market structure issue.

14. A system-wide diversion of PG&E's noncore customers has never been called since the diversion process was implemented in the Gas Accord.

15. Approval of PG&E's Winter Reliability Standard proposal would be a commitment to upgrades over four years with costs that are subject to change.

16. No one opposes the proposal to continue the Gas Accord structure for backbone transmission services.

17. Except for the concern about whether backbone level customers should have to pay local transmission charges, no one else opposes any other part of the proposal to continue the Gas Accord structure for local transmission service.

18. The uncertainty regarding what the future firm tariff rate will be, is just one risk factor the customer will analyze and consider.

19. Negotiated contracts for backbone transmission for up to five years is currently permitted.

20. The proposed change to the commensurate discount rule allows PG&E to operate with more flexibility with respect to the offering of discounts.

21. Although the avoidance of Commission-authorized charges is a concern from a revenue standpoint in this proceeding, this proceeding is not designed to determine whether bypass of these charges is occurring.

22. PG&E has not demonstrated that its allegations regarding bypass are occurring.

23. Since the proposed Winter Firm Capacity Requirement is not adopted, an adjustment to the assignment of storage capacity to Core Firm Storage needs to be made.

24. Core Firm Storage shall be assigned the following seasonal capacities for 2004: 156.6 MDth/d of injection; 33,477.7 MDth of inventory; and 1,111.2 MDth/d of withdrawal.

25. As a result of the denial of PG&E's request to sell 4.5 MMDth of non-cycle working gas, the proposed inventory level for Standard Firm Storage will be reduced from 9.4 MMDth to 4.8 MMDth.

26. The inventory reduction for Standard Firm Storage affects PG&E's proposed injection and withdrawal.

27. Standard Firm Storage shall be assigned the following seasonal capacities for 2004: 22.4 MDth/d of injection; 4,782.5 MDth of inventory; and 158.7 MDth/d of withdrawal.

28. Balancing shall be assigned the following for 2004: 76 MDth/d of injection; 4.1 MMDth of inventory; and 76 MDth/d of withdrawal.

29. No one objects to PG&E's proposal to provide Core Firm Storage to both its Core Procurement Department and to CPGs under a single tariff.

30. Since the Winter Firm Capacity Requirement is not adopted, the existing guideline in the Gas Accord shall be used to set the firm injection and withdrawal rights for CPGs that accept an assignment of less than 1000 MDth.

31. Since PG&E's proposed withdrawal rights are tied to the Winter Firm Capacity Requirement, the injection and withdrawal rights curve in Table 6-3 of Exhibit 1, and the overall ratio of injection to inventory to withdrawal, are affected by our non-adoption of the Winter Firm Capacity Requirement.

32. PG&E's seasonal adjustment in the injection and withdrawal rights curve appears to be of benefit in lowering the core storage rate, but there is insufficient information to allow us to develop a new injection and withdrawal rights curve which reflects seasonal use only.

33. Since the injection to inventory to withdrawal ratio affects the cost allocation for storage rates, the Gas Accord's assignment of injection, inventory, and withdrawal, as shown in Table 6.1 of Exhibit 1, and the Gas Accord's ratio of injection to inventory to withdrawal, shall be used for Core Firm Service in 2004.

34. Counter-cyclical storage rights provide CPGs with additional flexibility to meet their gas needs during the non-injection season.

35. This proceeding is not the appropriate forum to address PG&E's request to sell the non-cycle working gas.

36. PG&E's testimony lacks the necessary details for us to properly evaluate whether the sale of non-cycle working gas should be permitted.

37. The arguments of LGS and ORA against using rental compressors to provide additional firm injection for Schedule G-SFS, for balancing, and for providing counter-cyclical injection rights to the core, are offset by the benefits.

38. Since PG&E's request to sell 4.5 MMDth of non-cycle working gas is denied, the inventory assigned to Standard Firm Storage will be reduced to 4.8 MMDth.

39. The reduction in Standard Firm Storage affects the injection to inventory to withdrawal ratio, and PG&E's plans to adjust the withdrawal ratio for Schedule G-SFS customers.

40. Since the inventory remains unchanged from the Gas Accord, the Gas Accord's assignment of injection, inventory, and withdrawal, as well as the modifications for the counter-cyclical injection and withdrawal capacities assigned to Standard Firm Storage, as shown in Appendix A at page 29, shall be used for Standard Firm Storage in 2004.

41. Except for the concern about the use of rental compression, no one has objected to PG&E's proposed counter-cyclical storage rights for Standard Firm Storage.

42. The counter-cyclical service will provide Schedule G-SFS customers with additional flexibility to meet their gas needs.

43. The Gas Accord II Settlement Agreement did not address what kind of process there should be for obtaining transmission and storage capacity for 2004.

44. PG&E and the other parties were free in this proceeding to propose one or more processes to obtain transmission and storage capacity.

45. To allow an extension of a 2003 transmission contract for 2004, at the same price that was negotiated in 2003, would be unfair to both parties.

46. The need for transmission capacity to obtain the fuel for the DWR contracts was not raised in the testimony of any parties to this proceeding.

47. Based on PG&E's storage study, and assuming customer balancing behavior remains constant, PG&E predicts that an additional 25 MDth/d of injection will reduce the number of high OFOs by 20%, or by about 15 OFOs.

48. PG&E is the entity that has the responsibility and certificated authority to provide gas services to its customers.

49. No one has objected to PG&E's proposal to reclassify 2 MMDth of non-cycle working gas as working gas for use in its balancing service.

50. PG&E's daily imbalance limit proposal seems to affect a large group of customers who are not the cause of large system imbalances, and to impose an excess imbalance charge on them on a daily basis would be counterproductive.

51. The additional storage capacity for balancing should be used first to determine its effect on managing imbalances and OFOs before additional measures to remedy these problems are considered.

52. The current cash-out mechanism is advantageous for ratepayers.

53. The additional storage capacity for balancing should alleviate the effect of a cash-out on system operations.

54. PG&E's data shows that in 35 of 45 OFO events, California gas production imbalances exceeded the tolerance band required by the OFO.

55. PG&E has not demonstrated why the core's noncompliance charge for an EFO should be higher than the noncore's charge.

56. No party submitted any testimony or objected to the proposal that the EFO noncompliance charge for all CPGs be calculated using the lower of the Determined Usage or the end-of-flow-day core demand forecast, or the proposal that the EFO noncompliance charges for CPGs be set at a higher level than for noncore customers.

57. No party submitted any testimony or objected to the proposal to include the NAESB bumping process as part of the gas nomination process.

58. PG&E's curtailment process should be developed further before considering whether it should replace the diversion process.

59. No party submitted any testimony on the local curtailment process or the proposed noncompliance charge.

60. No other parties submitted testimony or filed comments on PG&E's shrinkage proposals.

61. Due to the non-adoption of PG&E's request to sell the non-cycle working gas, the storage cycle quantity has been changed, which affects the in-kind shrinkage allowance for the 2004 injection season.

62. Adding a gas index price as a component of the noncompliance charges will better reflect supply conditions and result in responsive behavior.

63. No party submitted testimony or commented on PG&E's proposal regarding the third party trading platform.

64. A comprehensive review of PG&E's expenses was not performed due to time and resource constraints of the parties.

65. The deadlines in the Pipeline Safety Act do not require the baseline integrity assessment to begin until mid-year of 2004.

66. Since much of the work related to the Pipeline Safety Act is not required to begin until mid-2004, the O&M expense for 2004 should be reduced by half.

67. PG&E's request for rate base treatment of its non-cycle working gas appeared in just several lines of text, and did not mention the rate base amount of $80.5 million or the revenue effect that this change in treatment would have.

68. PG&E did not comment on the rate base treatment of the non-cycle working gas in either its opening or reply briefs.

69. PG&E's position regarding its non-cycle working gas is contradictory, and it has not justified why the treatment of its non-cycle working gas should be changed in 2004.

70. Since much of the work related to the Pipeline Safety Act is not required to begin until mid-2004, the capital expenditures for 2004 should be reduced by half.

71. Since PG&E's proposal for a Winter Reliability Standard is not adopted, the forecast of expenditures to upgrade local transmission facilities is not needed.

72. A reduction to the 2004 capital expenditures for Power Plant Metering and Power Plant Connections should be made because the reduced number of new power plants was not reflected.

73. After the close of the evidentiary record in this proceeding, PG&E received $6 million in insurance proceeds in connection with the fire at the Gerber Compressor Station.

74. PG&E acknowledges that the $6 million in insurance proceeds should be used to reduce the cost of the new Gerber Compressor station.

75. The insurance recovery issue for the Gerber Compressor Station should be further explored in a separate application to determine if any additional insurance proceeds are forthcoming, and if so, what should be done with the proceeds.

76. This is the appropriate proceeding in which to address PG&E's cost of providing transmission and storage services to its customers, and to develop a revenue requirement and rates to recover those costs.

77. Updating the demand forecast at this point would be impractical given the time constraint.

78. The sensitivity runs that PG&E performed show that if power plants are delayed by one year, the 2004 EG throughput would be 14% higher, or using PG&E's EG forecast, it would increase to 663 MDth/d.

79. Using the sensitivity run for a one year delay, PG&E's total combined EG and cogeneration forecast would be 926.2 MDth/d.

80. Based on the information contained in the CEC report, PG&E's sensitivity run, and the forecast recommended by CCC/Calpine, PG&E's electric generation and cogeneration forecast for 2004 should not be changed.

81. PG&E is requesting that it be permitted to allow eligible off-system end users to connect directly to PG&E's backbone transmission service, while at the same time forecasting that its off-system throughput in 2004 will drop from 298 MDth/d to 219 MDth/d.

82. PG&E's off-system throughput should remain at 298 MDth/d for 2004.

83. PG&E's witness acknowledged that the 20% roll-in proposal is the beginning of a movement toward a full roll-in of Line 401 costs to the core.

84. The term "substantial customer benefits" originated in the Gas Accord decision in the section entitled "Features Opposing Approval" of the Gas Accord Settlement Agreement.

85. All of the passages in section 5.4 of D.97-08-055 make clear that the Commission's policy is in favor of incremental rates, and that the approval of the

Gas Accord Settlement Agreement "cannot be cited as precedent in favor of rolled-in rates."

86. The Gas Accord decision expressed a disfavor for any future request for a full roll-in of Line 401 costs if such a roll-in increase core or noncore rates.

87. D.94-02-042 assigned "all risks of undersubscription, and most of the risks of underutilization" of Line 401 to PG&E's shareholders.

88. PG&E's proposal to roll-in 20% of the costs of Line 401 in 2004 would affect core rates by approximately $17.7 million.

89. When high gas costs are factored in with the cost of a full or partial roll-in of Line 401 costs, core customers will experience rate shock.

90. When the regulatory history of Line 401, the commitments made by the Commission and PG&E, the prior decisions, and the additional costs, are considered against the substantial benefits the core may have received from Line 401, the considerations outweigh the substantial benefits, but may be considered again in the future.

91. PG&E and the other parties have come up with four different ways of calculating the load factor.

92. PG&E's use of the net firm capacity of 3195.292 MDth/das the denominator for the load factor is a departure from the design capacities used in the Gas Accord.

93. The load factor that we adopt will affect the rates, and PG&E's ability to recover the adopted revenue requirement.

94. PG&E's load factor of 68.4% for 2004 is quite a bit below the load factors that were experienced during the Gas Accord period.

95. The utilization factor of 95% that TURN uses in its load factor adjustment comes from D.94-02-042, and is very close to the load factors experienced on the combined Redwood paths during the Gas Accord period.

96. Using TURN's method of adjustment, and the off-system delivery adjustment in the demand forecast, the system load factor upon which backbone rates shall be based is 77.02%.

97. No one raised any objection to the use of the total net firm capacity to calculate the load factor, and to allocate the costs to the backbone paths.

98. No one objected to PG&E's proposal that the Redwood Path off-system rate be set to equal the Redwood on-system rate.

99. Requests for a backbone level rate have come before the Commission previously.

100. The cost impact examples show that the four-tier proposal and the backbone level proposal will shift the cost burden onto the core and the other customers who are not in a position to bypass the system.

101. The four-tier proposal and the backbone level proposal raise the fundamental issue of who should pay for the cost of facilities to serve customers.

102. Under a backbone level rate, customers connected to the backbone would avoid local transmission charges, and some of the costs these departing customers avoid will be shifted to the remaining customers.

103. A stranded cost charge could recover part of the avoided local transmission charges but none of the parties developed concrete suggestions for determining how much this charge should be.

104. Core wholesale customers have attributes, which clearly distinguish them as a noncore customer, and have been treated as such for more than 15 years.

105. The four-tier proposal and the backbone level proposal require careful thought on how far we should unbundle, and who will end up paying the costs, policies, which should be considered today.

106. The costs impacts to the core and to the noncore who are unable to build an interconnect to PG&E's backbone need to be carefully weighed against the costs for local transmission to the noncore customer that has built a lateral pipeline to the backbone system.

107. Since the O&M expenses and capital expenditures were at issue in this proceeding, resolution of the customer access charges will not be deferred.

108. None of the other parties presented any evidence to show that the growth in connections of electric generators over the last seven years has not raised PG&E's costs to connect these additional customers.

109. PG&E has not provided any support for adding two additional tiers to Schedule G-NT.

110. It is appropriate to consider PG&E's proposal to apply the Schedule G-NT rates to Schedule G-EG since one of PG&E's other proposals is for a single electric generation class.

111. No one opposed PG&E's proposal to impose a distribution rate component on the industrial transmission customer class, or its proposal to eliminate the cogeneration distribution shortfall rate component in the customer class charge.

112. No one opposed PG&E's proposal to change the transmission-level eligibility standard.

113. The issue of balancing account treatment for PG&E's noncore distribution revenues should be raised in PG&E's BCAP.

114. There are concerns about what the consequences might be for distributed generation if the proposal for a single electric generation class is adopted without modifications.

115. A single electric generation customer class was adopted for SoCalGas and SDG&E in D.00-04-060.

116. PG&E's proposed method of using an average heat rate for similarly sized electric generation facilities may not correctly reflect the customer's actual heat rate.

117. The significant financial impact of the distribution costs allocated to distribution level electric generation customers suggests that a rate shock would occur. Accordingly, PG&E may revisit this issue in their next Gas Accord filing.

118. PG&E's present method of recovering the distribution allocated to distribution level electric generation customers from all distribution and transmission-level customers equally should be adopted.

119. The Governmental Mechanism would allow PG&E to reach back in 2003 to include costs in its gas transmission and storage rates and charges for 2004.

120. The Governmental Mechanism is more favorable to PG&E's shareholders as compared to the z-factor that was agreed to in the Gas Accord.

121. The amount of firm interstate capacity at Topock is being addressed in Phase II of the El Paso proceeding.

122. PG&E has not sought to modify the CPIM.

123. SPURR/ABAG's spin-off proposal raises issues that are too complex to address in this proceeding.

124. PG&E's core transport paths, instead of unbundling the various ways in which gas ESPs can obtain gas, would require them to take service over the entire transport path.

125. An annual election to a pro rata share of the core transport paths, as opposed to the current monthly election, reduces the operating flexibility that gas ESPs have because it requires them to make an annual commitment for capacity.

126. PG&E already provides information regarding its monthly gas price.

127. There are still a number of issues regarding proposed Gas Rule 27 that the parties have not been able to agree on.

128. During the last five years, there have been no exceptional case facilities agreements for transmission-level facilities.

129. The projects that require interconnection to transmission-level service can or have used exceptional case agreements or the standard provisions of Gas Rules 2, 15 and 16.

130. No one objected to PG&E's off-system direct connect proposal.

131. No one objected to PG&E's request to continue the CGT Risk Management Program, or to the proposed changes which it seeks.

Conclusions of Law

1. The recommendation to extend the Gas Accord structure and current rates for 2004 is not adopted.

2. We adopt the Gas Accord market structure referenced in Finding of Fact 1, and as changed by the specific proposals adopted in today's decision, as the gas market structure for PG&E in 2004 and 2005.

3. PG&E has not met its burden of proving that the Winter Reliability Standard is needed at this point in time.

4. We do not adopt PG&E's proposal for a Winter Reliability Standard.

5. We do not adopt PG&E's proposal for a Winter Firm Capacity Requirement.

6. PG&E's proposal to continue the Gas Accord structure for backbone transmission service is adopted, and the other proposals that we adopt which affect this service, shall also be part of the structure for backbone transmission service.

7. PG&E's proposal to continue the Gas Accord structure for local transmission service is adopted, and the other proposals that we adopt which affect this service, shall also be part of the structure for local transmission service.

8. PG&E's proposal to offer long-term backbone transmission contracts for up to 15 years is adopted.

9. PG&E's proposal to change the commensurate discount rule is adopted.

10. PG&E's proposal to limit the MDQ of any as-available contract for backbone service to the expected usage of that contract by a shipper, and to reduce the contract's MDQ to the previous day's actual usage if scheduling non-performance continues, is adopted.

11. PG&E's proposal to impose a monthly reporting and registration requirement, and authority to charge for transportation charges, which allegedly have been avoided, is not adopted.

12. PG&E's proposal to use a single tariff, Schedule G-CFS, to provide Core Firm Storage to PG&E's Core Procurement Department and to CPGs is adopted.

13. PG&E's proposal to add firm counter-cyclical injection and withdrawal to Core Firm Storage is adopted.

14. PG&E's proposal to have Schedule G-SFS replace the existing Schedule G-FS is adopted, and such schedule shall conform to the other proposals that we adopt.

15. PG&E shall file a § 851 application if it wants to sell the non-cycle working gas.

16. PG&E's request to sell the 4.5 MMDth of non-cycle working gas is denied without prejudice.

17. PG&E shall be permitted to use rental compression to provide the injection for Schedule G-SFS, for balancing, and for providing counter-cyclical injection rights to the core.

18. PG&E's proposal to offer firm counter-cyclical storage rights to Schedule G-SFS customers is adopted.

19. PG&E's proposal for a contract extension and open season process as set forth in Appendix A of Chapter 7 of Exhibit 1 is adopted.

20. PG&E's proposal to increase its storage capacity for its balancing service is adopted.

21. PG&E's proposal to reclassify the 2 MMDth of gas as working gas for use in PG&E's balancing service is adopted.

22. PG&E's proposal for a daily imbalance limit and related excess imbalance charge is not adopted.

23. PG&E's proposal to replace the cash-out mechanism with an imbalance charge for monthly imbalances in excess of the tolerance band is not adopted, and PG&E shall continue to use the existing cash-out mechanism.

24. PG&E's proposal that the cash-out prices for terminated contracts be changed, is adopted.

25. PG&E's proposed application of the existing EFO and OFO rules to California gas producers in 2004 is not discriminatory.

26. PG&E's proposed application of the existing EFO and OFO rules to California gas producers in 2004 does not violate § 785 and 785.2.

27. PG&E's proposal to apply the same OFO and EFO tolerance bands and noncompliance charges that are currently in place for end-use customers, to California gas production, is adopted.

28. PG&E's proposal that the EFO noncompliance charge for CPGs be set at a higher level than for noncore customers is not adopted, and PG&E shall use the same EFO noncompliance charge for both CPGs and noncore.

29. PG&E's proposal to use the Determined Usage forecast to calculate the compliance of CPGs with flow orders is adopted.

30. PG&E's proposal that the EFO noncompliance charge for all CPGs be calculated using the lower of the Determined Usage or the end-of-flow-day core demand forecast, as compared to the CPG's scheduled supply, is adopted.

31. PG&E's proposal to include the NAESB bumping process as part of PG&E's gas nomination process is adopted.

32. PG&E's proposal to replace the existing diversion process with a curtailment process for 2004, and the related noncompliance charge, is not adopted.

33. PG&E's proposal that the current local curtailment process be continued is adopted for 2004 and 2005.

34. PG&E's proposal for a noncompliance charge for local curtailments for use in 2004 is adopted.

35. PG&E's proposal to allow PG&E to update its shrinkage allowances on an annual basis through an advice letter compliance, or more often if needed, is adopted.

36. PG&E's proposal that an in-kind shrinkage allowance be applied to all scheduled storage injection volumes is adopted.

37. PG&E's proposal that most of the noncompliance charges incorporate one of three relevant gas indexes is adopted.

38. PG&E is authorized to use the noncompliance charges shown in Table 8-6 of Exhibit 1 for 2004, except as noted in the text of this decision.

39. PG&E's proposal to eliminate the third party trading platform and services, and to credit the unused monies back to the BCA is adopted.

40. The adopted revenue requirement for 2004 shall serve as the maximum cap, and shall not be adjusted as a result of the fiscal impact that any of today's adopted adjustments may have on the revenue requirement.

41. The O&M expense for work related to the Pipeline Safety Act in 2004 shall be reduced by half.

42. PG&E's forecast of O&M expense for 2004, less the adjustment for the Pipeline Safety Act, is adopted.

43. PG&E's forecast of capital expenditures for 2004, less the adjustments we have made, is adopted.

44. Based on the proposals adopted in this decision, the adjustments to PG&E's forecast of O&M expenses and to its capital expenditures, a revenue requirement of $436,397,000 should be adopted for 2004.

45. Official notice is taken of the CEC report dated August 2003, which is entitled "Natural Gas Market Assessment."

46. The forecasts of demand and throughput and the backbone load factor adjustment that are shown in Table 13-1 of Exhibit 1, as modified by the increase to off-system delivery, is adopted for use in 2004.

47. The reference to substantial customer benefits must be read in context with the rest of the Gas Accord decision, including the noncore's willingness in the Gas Accord settlement to a partial roll-in of Line 401 costs.

48. The Gas Accord Settlement Agreement was adopted with the express understanding that "core retail and core wholesale customers will continue to benefit from low, vintaged rates on Line 400 and will not have to pay for Line 401 costs."

49. PG&E's proposal, and the other parties' proposals, to roll-in some or all of the costs of Line 401 to the core is not adopted at this time, but may be resubmitted in the future for further consideration.

50. Since we do not adopt the proposal to roll-in some or all of the costs of Line 401 to the core, CAPP's proposal for path-specific rates and for a postage stamp rate are not adopted.

51. Based on the load factors experienced during the Gas Accord period, and the need for just and reasonable rates while providing PG&E with the opportunity to recover its costs and a reasonable rate of return, an adjustment to PG&E's load factor using TURN's load factor method should be made so that PG&E's load factor correlates more closely to the load factors experienced during the Gas Accord period.

52. The adjusted load factor of 77.02% is at or below the load factors experienced on PG&E's transmission system during the Gas Accord period, and represents an equitable balance between just and reasonable rates, while providing PG&E with a reasonable opportunity to recover its revenue requirement.

53. The firm design capacities in Table 14.4 of Exhibit 3 are adopted, and they shall be used to allocate costs to the backbone paths, and for use in the denominator to calculate the adopted load factor of 77.02%.

54. PG&E's proposal that the Redwood off-system rate equal the Redwood on-system rate is adopted.

55. PG&E's proposal to assign vintage Redwood capacity to core retail and core wholesale is adopted.

56. Since the Winter Firm Capacity Requirement is not adopted, PG&E's assignment of non-vintage Redwood Path and Baja capacity shall remain at current levels.

57. PG&E's proposal that Schedule G-XF rates be designed on an incremental basis for 2004 is adopted.

58. The backbone rates attached to this decision in Tables 3 to 9 of Appendix A shall be adopted as the backbone rates in this proceeding.

59. PG&E's proposal to continue the rate design structure for Core Firm Storage is adopted.

60. PG&E's proposal to combine the capacity charge and the withdrawal charge into a single capacity charge on Schedule G-SFS is adopted.

61. PG&E's proposal to continue the self-balancing option is adopted.

62. Since we do not adopt the Winter Reliability Standard, TURN's suggestion that the local transmission cost allocation be done on the basis of a cold year non-coincident peak month is moot.

63. The path towards unbundling has not been and will not be painless.

64. PG&E shall review and consider a backbone level rate for noncore customers, coupled with a cost recovery surcharge, and or a modified four-tier local transmission rate for the noncore.

65. PG&E shall continue to use the existing cost allocation and rate design methodology from the Gas Accord for local transmission charges in 2004.

66. PG&E shall continue to use existing cost-allocation and rate design methodology from the Gas Accord for local transmission charges in 2004. PG&E's local transmission charges will remain non-bypassable for on-system

deliveries for 2004. During this time period, all customers that flow gas on PG&E's on-system backbone will continue to pay local transmission charges.

67. In 2005, PG&E shall implement a backbone level rate for noncore customers with new or incremental load after March of 1998.

68. PG&E's proposal to apply the Schedule G-NT customer access charges, as revised by this decision, to Schedule G-EG is adopted.

69. PG&E is permitted to update its cost of service for transmission-level customer level, as adopted in this decision, and PG&E shall continue to use the existing cost allocation.

70. PG&E's proposal to impose a distribution rate component on the industrial transmission customer class to recover the distribution costs allocated to this class is adopted.

71. PG&E's proposal to eliminate the cogeneration distribution shortfall rate component in the customer class charge is adopted.

72. PG&E's proposal to modify the transmission-level eligibility criteria is adopted.

73. PG&E's proposal to adopt 100% balancing account protection for PG&E's noncore distribution revenues is not adopted.

74. While PG&E's single electric generation customer class proposal treat attempts to electric generators alike, it does cause significant cost impacts to distribution–level customers.

75. PG&E is directed to adopt a single electric generator customer class but maintain the existing cost allocation structure for distributed generators and cogenerators.

76. PG&E's anti-gaming measure shall use the method set forth in Special Conditions 19 through 22 of SoCalGas' Schedule GT-F tariff.

77. PG&E shall implement the single electric generation class on April 1, 2004, to allow time to implement the adopted anti-gaming measure, and during the period from January 1, 2004 through March 31, 2004, PG&E shall apply the adopted 2004 revenue requirement allocated to electric generation and cogeneration customers to its existing rate design for cogeneration and electric generation customers.

78. PG&E's proposal for a single electric generation customer class, as revised by our discussion, is adopted, and PG&E should be directed to file an advice letter within 30 days to reflect how the distribution costs allocated to distribution-level electric generation customers will be recovered..

79. PG&E's proposal for a Governmental Mechanism is not adopted.

80. The z-factor adjustment from the Gas Accord shall be retained as part of the gas structure that we adopt for 2004 and 2005.

81. We authorize the continuation of the CEMA and HSM mechanisms as contingency adjustments to the gas structure.

82. PG&E shall be permitted to make an adjustment to replace the A&G placeholder with the A&G expenses adopted in PG&E's GRC.

83. PG&E is authorized to establish a memorandum account to track the difference between the A&G expenses authorized in this decision, with the amount adopted in the 2003 GRC, escalated to 2004, plus interest.

84. PG&E's proposal that additional storage withdrawal capacity be assigned to the core to meet the Winter Firm Capacity Requirement is not adopted.

85. PG&E's proposal to tailor the core's holdings of Baja transmission capacity to match the firm interstate capacity holdings at Topock is not adopted at this time.

86. PG&E's proposal to retain the current CPIM as the default incentive mechanism for PG&E's Core Procurement Department for 2004 and 2005, or until a revised CPIM is adopted by the Commission, is adopted.

87. PG&E's proposal to clarify the reliability planning standards, and to eliminate the alternate benchmark in the CPIM are not adopted because the Winter Firm Capacity Requirement is not adopted.

88. PG&E may make tariff changes that are consistent with the proposals that have been adopted in this decision.

89. Section 328.2 suggests that PG&E's Core Procurement Department cannot be spun-off unless there is a structure that allows the gas corporation to continue providing bundled basic gas service.

90. SPURR / ABAG's proposal to spin-off PG&E's Core Procurement Department is not adopted.

91. PG&E's proposal that gas ESPs serving core customers be subject to the same Winter Firm Capacity Requirement as PG&E's Core Procurement Department is moot because the Winter Firm Capacity Requirement is not adopted.

92. Gas ESPs serving core customers shall be allowed to obtain a proportionate share of core holdings on the GTN, Redwood, and Baja pipelines.

93. If capacity on El Paso and possibly Transwestern is assigned to the core and included as part of the CPIM, gas ESPs serving core customers shall be allowed a proportionate share of those holdings.

94. Based on the Commission's January 23, 2002 action, and the Gas Accord's precondition to NOVA and ANG capacity, we will not allow gas ESPs to obtain a proportionate share of those pipelines at this time.

95. Except for the changes related to the Winter Firm Capacity Requirement, PG&E may make the other changes to the core storage program.

96. For 2004 and 2005, the core firm storage provisions shall be based on D.00-05-049 and the adopted core firm storage changes.

97. PG&E's proposal to make it mandatory for gas ESPs serving core customers to accept a pro rata share of core transmission and storage capacity once the CAT program serves ten percent of peak core loads is adopted.

98. SPURR / ABAG's proposal for PG&E to provide information regarding its monthly gas price is not adopted.

99. PG&E's proposed Gas Rule 27 shall not be adopted at this time.

100. PG&E request to establish an off-system direct connect tariff, as clarified in today's decision, shall be permitted, and PG&E may file such a tariff via an advice letter filing.

101. PG&E is authorized to continue using financial derivative instruments to manage price and revenue risks pursuant to the CGT Risk Management Program that was approved in D.98-12-082, as modified in D.99-04-013, as extended by D.02-08-070, and as changed by today's decision.

102. The authority for PG&E to use financial derivative instruments to manage price and revenue risks pursuant to the CGT Risk Management Program shall expire on December 31, 2005, unless further extended by the Commission.

O R D E R

IT IS ORDERED that:

1. The existing gas market structure contained in Decision (D.) 97-08-055, as modified by D.00-02-050 and D.00-05-049, and as changed by the proposals adopted in today's decision, shall serve as the gas market structure for the gas

transmission and storage facilities and operations of Pacific Gas and Electric Company (PG&E) for 2004 and 2005.

a. The proposals adopted today, as set forth in the Conclusions of Law and as described and discussed in this decision, shall be incorporated into the gas market structure.

b. PG&E shall conduct its transmission and storage operations in accordance with the adopted gas market structure, and with all other applicable rules, regulations, and Commission decisions.

2. A revenue requirement of $436,397,000 is adopted for PG&E's gas transmission and storage facilities and operations for 2004.

a. The adopted revenue requirement is set forth in Tables 1 and 2 of Appendix A of this decision, and reflects the adopted adjustments that were made to PG&E's proposed revenue requirement for 2004.

3. The rates set forth in Tables 3 to 14 of Appendix A of this decision are adopted, and PG&E shall use these adopted rates in 2004 for its transmission and storage services.

4. Except as noted below, within five days of today's date, PG&E shall file an advice letter or letters to change all of its transmission and storage rates to reflect the adopted rates, and to change its affected gas schedules and rules to reflect the revised gas market structure as adopted in today's decision that will become effective January 1, 2004.

a. The advice letter filing(s) shall be consistent with and comply with the adopted revenue requirement and rates, and the adopted proposals concerning its transmission and storage operations and related issues.

b. The advice letter filing(s) shall go into effect January 1, 2004, and shall remain in effect, even if protested, until a Commission resolution or decision rescinds, suspends, or changes the rate(s) or practice(s) described in the advice letter filing(s).

c. The advice letter filing(s) may be protested, and such a protest shall be filed within ten days after the advice letter has been filed.

d. PG&E shall serve the advice letter filing(s) on the service list to this proceeding by e-mail and by mail.

5. PG&E is authorized to do the following:

a. To engage in the adopted contract extension and open season process using the rates adopted in this decision.

b. To continue using financial derivative instruments to manage price and revenue risks pursuant to the CGT Risk Management Program as adopted in today's decision.

c. To file an advice letter for a tariff which allows off-system end users the ability to directly connect to PG&E's backbone transmission facilities, as discussed and adopted in today's decision.

d. Submit an advice letter filing establishing a memorandum account to track the difference between the placeholder amount for the Administrative & General (A&G) expenses adopted in this decision, and the A&G amount to be adopted in PG&E's 2003 General Rate Case, escalated to 2004, plus interest.

6. PG&E shall do the following:

a. For 2004, submit its annual advice letter filing regarding transmission and distribution shrinkage allowances, which shall be filed on or before December 31, 2003, with an effective date of January 1, 2004.

b. On or before March 19, 2004, file an advice letter which calculates the in-kind storage shrinkage allowance for the 2004 injection season, with an effective date of April 1, 2004.

c. Monitor the effectiveness of the additional storage capacity in its daily operations and balancing, and include in its transmission and storage rate case for 2005, a report about the additional storage capacity, and its effects on system balancing and operations.

d. Work with the California Natural Gas Producers Association and interested California gas producers to resolve operational issues regarding flow orders.

e. File an application within 90 days of today's date addressing the status of any possible remaining insurance claims with respect to the fire at the Gerber Compressor Station, and what should be done with any insurance proceeds.

f. File on or before March 19, 2004, its gas transmission and storage rate case application for 2005.

g. File on or before March 19, 2004, its gas transmission and storage rate case application for 2005.

h. File on or before March 19, 2004, several rate design proposals that provide a backbone level rate structure for qualified end-use customers, one of which will be adopted in its gas transmission and storage rate case application for 2005.

i. We direct PG&E to file an advice letter within ten days of this decision that develops a rate table that reflects our determination that rates for distribution-level electric generators are to remain as currently calculated.

j. File an application no later than February 4, 2005 proposing the kind of gas market structure and rates that PG&E's gas transmission and storage system should operate under beginning January 1, 2006 for transmission, and April 1, 2006 for storage services, respectively, and how long the rates and such a structure should remain in place.

k. Within 30 days of today's date, PG&E shall file an advice letter or letters to implement the adopted rates, and to change its affected gas schedules and rules associated with implementing the single electric generation class as discussed in the decision, which will become effective April 1, 2004.

l. Within 30 days of today's date, PG&E shall file an advice letter or letters to implement the adopted rates, and to change its affected gas schedules and rules associated with implementing the storage provisions that will become effective April 1, 2004.

7. Application 01-10-011 is closed.

This order is effective today.

Dated December 18, 2003, at San Francisco, California

MICHAEL R. PEEVEY
President

GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I reserve the right to file a dissent.

/s/ CARL W. WOOD
Commissioner

I reserve the right to file a dissent.

/s/ LORETTA M. LYNCH
Commissioner

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APPENDIX A

APPENDIX B

2004 GAS STRUCTURE MATRIX

Proposal Description	Adopt	Adopt As Changed	Do Not Adopt
Should the current Gas Accord structure, rates, and terms and conditions, as modified and extended through 2003, be extended through 2004?			X
Should the Commission adopt a gas market structure for PG&E's transmission and storage systems for 2004 and 2005 that is based on the Gas Accord structure, as changed and extended by prior decisions, and as changed by the proposals adopted in this decision?	X		
Should PG&E's proposal for a 1-in-10 year cold temperature Winter Reliability Standard for the design of PG&E's local transmission and central backbone facilities be adopted?			X
Should PG&E's proposal for a Winter Firm Capacity Requirement for all CPGs be adopted?			X
TURN's proposal to change the peak month allocator if the Winter Reliability Standard is adopted.			X
LGS' proposal that third party storage providers be allowed to provide the additional withdrawal capacity created by the need to meet the Winter Reliability Standard.			X
PG&E's proposal to continue the Gas Accord structure for backbone transmission service.	X		
PG&E's proposal to continue the Gas Accord structure for local transmission service.	X		
PG&E's proposal to offer long-term backbone transmission contracts for up to 15 years.	X		
PG&E's proposal to change the commensurate discount rule.	X		
PG&E's proposal regarding scheduling non-performance.	X		
PG&E's bypass reporting and registration			X

proposal.			
PG&E’s proposed assignment of storage capacity for 2004.		X	
PG&E’s proposal to use Schedule G-CFS to serve its Core Procurement Department and CPGs.	X		
Use existing guideline in the Gas Accord to set the firm injection and withdrawal rights for CPGs accepting a storage inventory of less than 1000 MDth.	X		
PG&E’s proposal to use the injection and withdrawal rights curve for CPGs shown in Table 6-3 of Exhibit 1.			X
Use the Gas Accord’s assignments for Core Firm Storage in 2004, and the Gas Accord’s ratio for Core Firm Storage in 2004.	X		
PG&E’s proposal to add firm counter-cyclical injection and withdrawal to Core Firm Storage.	X		
PG&E’s proposal to have Schedule G-SFS replace Schedule G-FS.		X	
PG&E’s request to sell 4.5 MMDth of non-cycle working gas.			X
PG&E’s proposal to use rental compressors.	X		
Use the Gas Accord’s assignments for Standard Firm Storage in 2004, and the Gas Accord’s ratio for Standard Firm Storage in 2004.	X		
PG&E’s proposal to add firm counter-cyclical storage rights to Standard Firm Storage.	X		
PG&E’s proposal to offer long-term firm storage contracts.	X		
PG&E’s proposal for a 2004 contract extension and open season.	X		
Other parties’ proposal for a full open season for transmission and storage capacity.			X
Should PG&E be required to extend a negotiated contract at the same negotiated contract price?			X
NCGC’s suggestion to add capacity amounts to shippers’ name on the Pipe Ranger website.			X

NCGC's recommendation to add an additional 25 MDth / d of injection to balancing.			X
PG&E's proposal to increase its storage capacity for balancing.	X		
PG&E's proposal to reclassify 2 MMDth of non-cycle working gas as working gas for its balancing service.	X		
PG&E's proposal to impose a daily imbalance limit and a $0.25 per Dth excess imbalance charge.	X		
PG&E's proposal to replace the current cash-out process with an imbalance charge (market-index based) for monthly imbalances in excess of the tolerance band, and that the customer be responsible for ultimately clearing its entire physical imbalance.			X
PG&E's proposal that the cash-out prices for terminated contracts be changed.	X		
PG&E's proposal to apply the OFO and EFO intolerance bands and noncompliance charges to California production imbalances.	X		
PG&E's proposal that the EFO noncompliance charge for CPGs be set at a higher level than noncore customers.	X		
PG&E's proposal to change the forecast used to determine a CPG's OFO and EFO compliance.	X		
PG&E's proposal to base the noncompliance charge using the lower of the Determined Usage Forecast or the end-of-flow day core demand forecast.	X		
PG&E's proposal to implement the NAESB bumping process as part of the nomination process.	X		
PG&E's proposal to replace the current diversion process with its proposed curtailment process.			X
PG&E's proposal to continue the local curtailment process.	X		
PG&E's proposal to impose a local curtailment	X		

noncompliance charge.			
PG&E's proposal to adjust shrinkage on a yearly basis, and additional adjustments during the year as may be needed.	X		
PG&E's proposal for a gas storage shrinkage allowance.		X	
PG&E's proposal that the noncompliance charges shown in Table 8-6 of Exhibit 1 include a cost of gas component.		X	
PG&E's proposal that the third party electronic trading platform adopted in D.00-05-049 be terminated, and the unused funds credited back to the BCA.	X		
Whether an adjustment to PG&E's O&M expense for the Pipeline Safety Act should be made.	X		
TURN's proposal for three adjustments to PG&E's O&M expenses.			X
PG&E's forecast of O&M expenses for 2004.		X	
PG&E's proposal to add $80.5 million of non-cycle working gas to ratebase for 2004.			X
Should the capital expenditures for the Pipeline Safety Act be reduced by half to reflect the deadlines for starting the assessment work?	X		
Should the $2 million in capital expenditures for upgrading of local transmission facilities to meet the Winter Reliability Standard be removed?	X		
Should the capital expenditures for Power Plant Metering and Power Plant Connections be reduced to reflect fewer power plants being built?	X		
TURN's proposal that a prudency hearing be held to look into the circumstances regarding the Gerber Compressor Station fire, and whether a memorandum account should be established.		X	
PG&E's forecast of capital expenditures for 2004.		X	

PG&E's proposed revenue requirement of $454 million for 2004.			X
Should a total revenue requirement of $436,397,000 for PG&E's gas transmission and storage systems be adopted for 2004?	X		
Proposals to update the demand forecasts.			X
Whether PG&E's demand forecasts should be adopted.		X	
Whether PG&E's EG demand forecast should be changed.			X
Whether PG&E's off-system delivery forecast should be changed.	X		
Whether PG&E's backbone throughput adjustment should be adopted.	X		
Core vintage Line 400 Redwood Path rates to be 20% rolled-in with noncore Redwood Path costs for 2004.			X
Proposals of other parties for a full roll-in of Line 401 costs to the core.			X
PG&E's proposal to design backbone rates using a system average load factor of 68.4%.			X
Should PG&E's load factor be adjusted?		X	
PG&E's use of net firm capacity to calculate the load factor and to allocate costs		X	
PG&E's proposal that the Redwood Path off-system rate be set to equal the Redwood Path on-system rate.	X		
PG&E's proposal to assign vintage Redwood capacity to core retail and core wholesale.	X		
PG&E's proposal to assign non-vintage Redwood Path and Baja to the core to meet 1-in-10 year demand requirements.			X
PG&E's proposal that Schedule G-XF rates be designed on an incremental basis.	X		
PG&E's proposal to continue the rate design structure for Core Firm Storage.	X		
PG&E's proposal to simplify the G-SFS storage rate design by combining two charges into a single capacity charge.	X		

PG&E proposes to continue the self-balancing service option.		X	
PG&E's proposal that local transmission rates for noncore utilize a four-tier rate design based on a customer's annual usage.			X
Proposal for a backbone level rate.			X
PG&E's proposal to add two tiers to Schedule G-NT.			X
PG&E's proposal to apply the customer access charges in Schedule G-NT to Schedule G-EG.		X	
PG&E's proposal to impose a distribution rate component on the industrial transmission customer class to recover the distribution costs.	X		
PG&E's proposal that the cogeneration distribution shortfall rate component in the customer class charge be eliminated.	X		
PG&E's proposal to modify the transmission-level eligibility criteria.	X		
PG&E's proposal for 100% balancing account protection for noncore distribution revenues.			X
PG&E's proposal for a single electric generation customer class.		X	
PG&E's proposal that the Governmental Mechanism replace the z-factor adjustment.			X
Should the z-factor adjustment of the Gas Accord be retained as part of the gas market structure for 2004 and beyond.	X		
PG&E's proposal to retain the CEMA and HSM adjustment mechanisms.	X		
PG&E's proposal to create a memorandum account, with interest, to track the difference in A&G expenses adopted in the 2003 GRC, with escalation, to the A&G placeholder for the 2004 gas structure, and to file an adjustment by an advice letter filing.	X		
PG&E's proposal to increase the core firm storage assignment through 75 MDth/d of withdrawal capacity.			X
PG&E's proposal to match core holdings on the			

Baja Path with the firm interstate capacity holdings at Topock.			X
PG&E's proposal that the current CPIM, and that it reflect the new core Winter Firm Capacity Requirement and additional capacity additions, be adopted as the default structure until a revised CPIM is adopted.			X
Should the current CPIM be adopted as the default incentive mechanism for 2004-2005, or until a revised CPIM is adopted.	X		
PG&E's proposals to clarify the reliability planning standards and to eliminate the alternate benchmark in the CPIM.			X
PG&E's proposal to make a series of tariff changes.		X	
SPURR/ABAG's proposal to spin-off PG&E's Core Procurement Department.			X
PG&E's proposal that gas ESPs serving core customers be expected to conform to the Winter Firm Capacity Requirement.			X
PG&E's proposal that gas ESPs serving core customers have the option to obtain pro rata shares of core transmission capacity over four core transport paths.			X
PG&E's proposal that five changes be made to the core firm storage program.		X	
PG&E's proposal that once the CAT program grows beyond 10% of core load, that the storage and transportation options become mandatory assignments.	X		
SPURR/ABAG proposal that PG&E provide additional information regarding its core procurement pricing.			X
PG&E's proposal to adopt new gas Rule 27 regarding interconnection services.			X
PG&E's proposal to establish a new tariffed service to allow eligible off-system end users to connect directly to PG&E's backbone.		X	
PG&E's proposal to continue the use of the			

CGT Risk Management Program, and to make some modifications to the program.	X		

(END OF APPENDIX B)