Application of PACIFIC GAS AND ELECTRIC COMPANY (U 39 G) for an Order Pursuant to Section 1005.5(b) of the Public Utilities Code to Increase the Maximum Cost Specified in PG&E's Certificate of Public Convenience and Necessity to Construct the California Portion of the Expansion of its Natural Gas Pipeline.
And Related Matters

Decision No. 97–08–055, Application No. 92–12–043 (Filed December 21, 1992), Application No. 93–03–038, Application No. 94–05–035, Application No. 94–06–034, Application No. 94–09–056, Application No. 94–06–044, Application No. 96–08–043, Rulemaking No. 90–02–008, Rulemaking No. 88–08–018, Rulemaking No. 92–12–016, Investigation No. 92–12–017, Application No. 92–07–049, Application No. 95–02–008, Application No. 95–02–010, Application No. 94–11–015, Application No. 93–04–011, Application No. 94–04–002, Application No. 95–04–002, Application No. 96–04–001, Application No. 94–12–039

California Public Utilities Commission

1997 Cal. PUC LEXIS 763; 179 P.U.R.4th 485

August 1, 1997

(See Decision (D.) 93–10–069, D.94–12–061, and D.96–09–095 for appearances; see Appendix A for additional appearances.)

PANEL: [*1] P. Gregory Conlon, President, Jessie J. Knight, Jr., Henry M. Duque, Josiah L. Neeper, Richard A. Bilas, Commissioners

OPINION: SIXTH INTERIM OPINION

1. Summary of DecisionA comprehensive settlement known as the **Gas Accord** is approved as clarified. The **Gas Accord** resolves issues in five phases of the first general rate case for Line 401, the California segment of a pipeline expansion project owned and operated by Pacific Gas and Electric Company (PG&E). The five phases cover: (1) market issues, including terms and conditions of service on Line 401; (2) amortization of costs recorded in PG&E's interstate transition cost surcharge (ITCS) balancing account; (3) a reopening of PG&E's decision to construct the pipeline expansion; (4) two competing settlements, the **Gas Accord** and a separate Joint Recommendation; and (5) Line 401 capital costs and operations and maintenance expenses.While the Commission is approving the **Gas Accord,** the Commission nevertheless finds that PG&E holds market power in California, that PG&E has a present conflict of interest in marketing Line [*2] 401 capacity on behalf of shareholders and brokering unused Southwest capacity on behalf of ratepayers, that under the **Gas Accord** PG&E will have a conflict of interest in marketing Line 400/401 capacity on behalf of shareholders and against discounting Line 300 capacity on behalf of noncore customers, and that PG&E may have conflicts of interest in its procurement of gas for its core customers. Rather than reject the **Gas Accord,** the Commission will impose a discounting rule in its order approving the **Gas Accord.** This rule is necessary to mitigate PG&E's conflict of interest and to enable fair competition between Canadian, California, and Southwest supply sources. The Commission can further address PG&E's continuing conflicts of interest in other proceedings.The Commission leaves undisturbed previous findings that PG&E's October 25, 1991, decision to construct Line 401 was reasonable. While the Commission will not allow private parties in the **Gas Accord** to settle alleged Rule 1 violations concerning PG&E's testimony about its decision to construct Line 401, the Commission finds that a separate settlement of the alleged Rule 1 violations negotiated by the Commission's Consumer Services [*3] Division and PG&E is in the public interest.The Joint Recommendation is rejected because it would hinder progress toward unbundled rates, and the **Gas Accord** with a discounting rule reaches a more desirable outcome.

2. Background This consolidated proceeding is the first general rate case for PG&E's Line 401, the California segment of a natural gas pipeline expansion project that extends from Alberta, Canada to Kern River Station in Southern California.

The Commission granted a Certificate of Public Convenience and Necessity for the California segment in Decision (D.) 90-12-119, issued December 27, 1990, which was predicated upon incremental pricing. n1 The pipeline went into service on November 1, 1993. Line 401 has a design firm delivery capacity of 755 million cubic feet per day (MMcf/d), and an average annual firm capacity of 851 MMcf/d. Prior opinions describe the mechanical features of Line 401 and historical and procedural background through early August 1996. n2

n1 39 CPUC2d 69, 166 (1990).
n2 D.94-02-042, Third Interim Opinion, 53 CPUC2d 215, 222-223 and Appendix A at 254 (1994); D.96-09-095, Fifth Interim Opinion, at mimeo. pp. 2-6 (1996).

[*4] The Commission has issued nine decisions in this proceeding, and three related resolutions. Four actions stand out: (1) D.93-10-069 authorized temporary interim rates and terms and conditions of service, effective when Line 401 went into commercial operation; (2) D.94-02-042 increased a previously ordered cost cap, set interim rates, and found PG&E's decision to construct Line 401 to be reasonable; (3) D.94-12-061 ordered a scheme of receipt point capacity allocation (RPCA) at the California-Oregon border, and authorized direct connections to Line 401 in limited circumstances; and (4) D.96-09-095 terminated a backbone credit mechanism intended to relieve Line 401 shippers from certain duplicative charges. Several petitions for modification of those decisions are outstanding, but we do not address the petitions in this decision.Parties litigated the reasonableness of PG&E's decision to construct Line 401 in an earlier phase of this proceeding, and adopted a finding of reasonableness in D.94-02-042. n3 On June 27, 1995, administrative law judge (ALJ) James Weil reopened the decision to construct in order to review new evidence. Norcen Energy Resources Limited (Norcen) and other parties [*5] claim that PG&E violated Rule 1 of the Commission's Rules of Practice and Procedure by concealing critical documents. The reopening began with the revelation—in another proceeding—of an October 24, 1991, memorandum from PG&E Vice President Jerry R. McLeod to several PG&E managers and attorneys (McLeod memo). n4 The memo is a 42-page document, including a cover memo, an eight-page presentation prepared for an October 25, 1991, meeting of the PG&E steering committee that would make the decision to go forward with the expansion project, and several attachments. The most significant attachment is an economic study by McKinsey & Company, a management consulting firm. The principals in the dispute over the decision to construct are PG&E versus Norcen, Toward Utility Rate Normalization (TURN), n5 and El Paso Natural Gas Company (El Paso). Other parties presented arguments in briefs.

n3 D.94-02-042, Finding of Fact 11, 53 CPUC2d 215, 248 (1994).
n4 Exhibit 455 in this proceeding, Exhibit 263 in A.93-04-011.
n5 Effective November 13, 1996, Toward Utility Rate Normalization changed its name to The Utility Reform Network. The acronym TURN is unchanged.

[*6] The first seven applications listed in the caption for this decision, beginning with Application (A.) 92-12-043 and ending with A.96-08-043, comprise the Line 401 general rate case and are consolidated without restriction. Before August 1996 there were four active phases in the proceeding: (1) a market issues phase, including many general rate case issues; (2) an ITCS phase, by consolidation with A.94-06-044, in which PG&E seeks to amortize in rates the charges recorded in its ITCS balancing account; (3) a reopening of PG&E's decision to construct the pipeline expansion; and (4) a Pipeline Expansion Project Reasonableness (PEPR) phase, covering capital costs and incremental operating and maintenance expenses.On August 21, 1996, PG&E filed concurrently A.96-08-043 and a motion in this and other proceedings, which together seek Commission approval of a broad settlement known as the **Gas Accord.** In a ruling issued October 18, 1996, the ALJ consolidated the proceedings covered by the motion solely for purposes of considering the **Gas Accord.** On September 24, 1996, three parties filed a motion for Commission approval of a Joint Recommendation intended to supplant many provisions of the [*7] **Gas Accord.** Together, the **Gas Accord** and the Joint Recommendation are the subjects of a fifth active phase of the consolidated proceeding. This decision will address all five active phases.Market issues are the subject of market assessment reports prepared by several parties, a market assessment workshop, post-workshop comments, prepared testimony, hearings, and briefs. ITCS issues are also fully developed in prepared testimony, hearings, and briefs. The combined record on market and ITCS issues includes 163 exhibits, transcripts of 35 days of hearings, and opening and reply briefs. n6 The record on the decision to construct includes 161 exhibits, transcripts for eight days of hearings, portions of the same opening and reply briefs, and supplemental briefs. n7

n6 Exhibits 201 through 362, and Exhibit 561, a comparison exhibit; Transcript Volumes 34 through 68, taken at hearings beginning April 1 and ending June 5, 1996; opening and closing briefs, filed June 26 and August 9, 1996.
n7 Exhibits 401 through 560, and 562; Transcript Volumes 69 through 76, taken at hearings beginning June 10 and

ending June 20, 1996; opening and closing briefs, filed June 26 and August 9, 1996; and supplemental briefs, filed October 26, 1996.

[*8] No formal hearings were held regarding the **Gas Accord** and the Joint Recommendation. Instead, we rely on pleadings, questions and answers filed following two workshops, and filed comments. The record on the **Gas Accord** begins with A.96-08-043 and five PG&E documents associated with the application. n8 The ALJ led unreported workshops on September 11-12 and November 5, 1996. The first workshop was generally dedicated to details of the **Gas Accord.** The second workshop covered: (1) a supplemental report on a post-1997 Core Procurement Incentive Mechanism (CPIM), an element of the **Gas Accord** that was incomplete when the **Gas Accord** was filed; (2) the Joint Recommendation; and (3) remaining **Gas Accord** topics. The central purposes of the workshops were to develop questions and clarify uncertainties about the **Gas Accord** and the Joint Recommendation. The parties answered the questions and discussed contested issues in subsequent written comments. Workshop discussions are not part of the record.

n8 The documents are: (1) PG&E's "Report on the **Gas Accord** Settlement," which has the character of prepared testimony; (2) Appendix 1, which is the **Gas Accord** itself; (3) a two-page document containing revised Tables 15 and 18 in Appendix 1, distributed by PG&E on September 11, 1996; (4) Appendices 2 and 3 to the report, containing recommendations by two customer advisory groups; and (5) a compendium of **Gas Accord** work papers.

[*9] Formal record documents related to the **Gas Accord** include: (1) PG&E's August 21, 1996, motion to adopt the **Gas Accord;** (2) filed responses to the August 21 motion; (3) PG&E's October 18, 1996, motion to supplement A.96-08-043 with a post-1997 CPIM report, and the attached report; (4) four rounds of comments following the two workshops, filed September 24, October 4, November 14, and November 21, 1996; (5) a PG&E addendum to its November 14 comments, filed the next day; (6) PG&E supplemental comments filed on November 22, 1996, with the permission of the ALJ; (7) copies of side deals with four Line 401 shippers, and **Gas Accord** agreements executed by PG&E and three of the four shippers, attached to PG&E procedural comments filed December 5, 1996; (8) a copy of a **Gas Accord** agreement executed by the fourth shipper, attached to supplemental procedural comments filed by PG&E on December 9, 1996; and (9) two rounds of comments on the side deals, filed December 20 and December 30, 1996.The record on the **Gas Accord** does not include draft implementation tariffs distributed by PG&E, or any written information relating to informal tariff workshops held by PG&E beginning in November 1996. Parties [*10] may raise concerns about tariffs when tariff revisions are filed for Commission approval.The record on the Joint Recommendation includes the September 24, 1996, motion for adoption; filed responses to the motion; questions and answers contained in post-workshop comments filed on November 14, 1996; and discussion embedded in reply comments filed November 21, 1996.Although the parties have served prepared testimony in the PEPR phase, hearings have not been convened. The **Gas Accord** would settle most PEPR issues.Many parties actively participated in developing the record supporting this decision. Seventeen parties signed the **Gas Accord** before it was filed: (1) Amoco Canada Marketing Company, Amoco Energy Trading Corporation, and Amoco Production Company (together, Amoco); (2) California Cogeneration Council (CCC); (3) California Independent Producers Association (CIPA); (4) California Industrial Group (CIG); (5) California League of Food Processors (CLFP); (6) California Manufacturers Association (CMA); (7) City of Palo Alto (Palo Alto); (8) CNG Power Services Corporation; (9) Division of Ratepayer Advocates (DRA); n9 (10) Enron Capital & Trade Resources; (11) Enserch Energy Services [*11] (Enserch); (12) International Brotherhood of Electrical Workers; (13) PG&E; (14) School Project for Utility Rate Reduction and Regional Energy Management Coalition; (15) Sacramento Municipal Utility District (SMUD); (16) Suncor, Inc.; and (17) Transwestern Pipeline Company (Transwestern). Two parties wrote letters of support to PG&E, but did not execute **Gas Accord** agreements prior to PG&E's filing of A.96-08-043: U.S. Defense Logistics Agency, Defense Fuel Supply Center; and Northern California Power Agency (NCPA). In its September 24, 1996, post-workshop comments, Southern California Edison Company (Edison) announced its intent to sign the **Gas Accord,** but did not include an executed agreement. Formal support for the **Gas Accord** by Edison and four other shippers was revealed in attachments to PG&E's December 5 and December 9, 1996, comments. The four other shippers are San Diego Gas & Electric Company (SDG&E), NCPA, Rigel Oil & Gas Ltd., and Ulster Petroleums Ltd.

n9 Effective September 10, 1996, the Executive Director abolished the DRA as an organizational unit at the Commission. Former DRA professional staff working on this proceeding are redeployed to a new Office of Ratepayer Advocates (ORA). Because the **Gas Accord** and initial related pleadings were filed prior to abolishment, this decision recognizes both DRA and ORA as the Commission's advocacy staff.

[*12] Three parties sponsor the Joint Recommendation: Department of General Services of the State of California (DGS);

Department of Energy, Minerals & Natural Resources and the State Land Office of the State of New Mexico (together, New Mexico); and TURN.Several other parties actively participated in hearings and workshops: (1) Alenco Gas Services, Inc.; (2) DEK Energy Company and Apache Canada Ltd. (together, Apache); (3) Burlington Resources; (4) Canadian Association of Petroleum Producers (CAPP); (5) CanWest Gas Supply U.S.A., Inc. (CanWest); (6) Chevron U.S.A. Inc. (Chevron); (7) El Paso; (8) Foster Associates; (9) Independent Energy Producers Association; (10) Interstate Gas Services, Inc.; (11) Mock Energy Services, L.P.; (12) Natural Gas Clearinghouse, Inc.; (13) Norcen; (14) North American Chemical Company; (15) Pacific Gas Transmission Company (PGT), the PG&E subsidiary that owns and operates the segment of the pipeline expansion from the Canadian border to the California-Oregon border; (16) PanCanadian Petroleum, Ltd.; (17) Southern California Gas Company (SoCalGas); (18) Southern California Utility Power Pool and Imperial Irrigation District, acting principally on behalf of [*13] three Line 401 firm shippers, which are the Cities of Burbank, Glendale, and Pasadena; and (19) Wild Goose Gas Storage Company (Wild Goose).The record supporting this opinion was submitted for Commission decision on December 31, 1996, by ALJ ruling following receipt of reply comments on side deals associated with the **Gas Accord.**

3. Market AssessmentPG&E originally intended that Line 401 would transport Canadian gas only to Southern California. When Southern California demand did not fill the pipeline, PG&E looked to Northern California markets. Today Line 401 offers gas transportation service from the California-Oregon border at Malin, Oregon, to Southern California at Kern River Station, the southern terminus, and to Northern California at intermediate points. Coupled with downstream pipeline systems operated by PG&E, SoCalGas, and SDG&E, Line 401 can serve end users in most of California.The connecting distribution systems operate largely without constraints or bottlenecks. The same is not true for transmission-level alternatives to Line 401. PG&E's Line 400 parallels Line 401 from Malin to the Antioch terminal. Line 400 has lower embedded costs and lower rates than Line [*14] 401. Demand for Line 400 service, driven by Canadian gas supply prices that are lower than competing Southwest U.S. supply prices, almost always exceeds the capacity of Line 400. Correspondingly, interstate pipelines that deliver gas from the Southwest into California now operate at low capacity factors. With Line 400 generally operating full, Line 401 competes directly with Southwest interstate pipelines. California gas supplies do not have the capacity to alter the basic features of this competition.Marketers now dominate gas sales to noncore end users in PG&E's service territory. End users are generally concerned with burnertip prices, not gas supply basins or transportation routes. Among noncore customers, only PG&E's utility electric generation (UEG) department and a few large end users actively purchase gas at supply basins, then arrange for transportation service.Demand in excess of capacity on Line 400 has led to market responses that vex market participants. In D.94-12-061, issued December 21, 1994, the Commission ordered an RPCA scheme at Malin that allocates to noncore shippers the available pipeline capacity on Lines 400 and 401. The adopted scheme is based on end-use [*15] priorities, and continues a "crossover ban" previously ordered by the Commission as an essential element of incremental ratemaking for the new pipeline. Under the crossover ban, quantities of gas transported anywhere on the PGT portion of the expansion project are subject to incremental Line 401 rates in California. Marketers have responded to RPCA rules and the crossover ban by transferring ownership of gas packages upstream from Malin, by direct sales or exchange agreements, and by overnominating daily deliveries into Line 400. There is no consensus among the parties or among pipeline customers on how to resolve RPCA problems.In its market assessment report, PG&E concludes that regional gas markets are competitive and are becoming increasingly integrated. n10 According to PG&E, an economic link exists between Canadian and Southwest supply basins, despite their geographic separation. Price changes in Canada or the Southwest are transmitted to the other region through competitive interactions in California, which is the contested consuming market.

n10 Exhibit 207, Chapter 3C.

[*16] Other parties discuss more specific market features in their market assessment reports, which are attached to September 20, 1995, post-workshop comments. Amoco, PGT, and Wild Goose recite problems with the crossover ban, the existing RPCA scheme, overnominations at Malin, and peculiar market rules. CanWest reminds the Commission that gas supplies are developed in British Columbia as well as Alberta, Canada. CIPA notes that PG&E still holds a monopoly on most intrastate transportation service within its service territory. El Paso believes that PG&E has a conflict of interest in operation of Line 401, and that ratepayers are harmed by the crossover ban. PG&E and Edison claim that Canadian competition has lowered overall gas prices in California, despite market problems.PG&E sets prices for as-available service on Line 401 based on competitive alternatives at Topock, Arizona, the principal receipt point for Southwest gas that enters California. In review of the **Gas Accord** and other issues in this proceeding, we should examine PG&E's market power, now and under the **Gas Accord** and other future ratemaking scenarios. We define market power as the

ability to sustain revenues, through increased [*17] prices or sales, above competitive levels for a significant period of time.

3.1 Measures of Market Behavior There is much information in the record about PG&E's market behavior, but we will endorse no single measure of market power. Instead, we begin by looking at five characteristics of PG&E's participation in gas transportation markets: (1) sufficiency of supply and transportation alternatives, (2) assured sales, (3) the Herfindahl–Hirschman Index (HHI), (4) mitigation and regulation effects, and (5) geographic constraints. PG&E asserts that it has little market power because it cannot sustain control over gas prices at Topock. Whether that single statement is true or not, we must take a broader view of possible market power. PG&E holds virtual monopoly power over intrastate transportation in Northern California.PG&E claims that it acts as a price follower when it sets Line 401 rates because PG&E has no ability to control market prices. According to PG&E, SoCalGas is the price leader at Topock. PG&E recites several supply alternatives for noncore end users: Southwest gas transported on the El Paso, Kern River Gas Transmission Company, and Transwestern pipelines; California [*18] gas; and gas withdrawn from storage. However, PG&E sets Line 401 prices based on only one of those alternatives—El Paso deliveries to Topock. This competition between only two supply sources suggests that PG&E might have significant market power.On the other hand, the capacity of Line 401 is less than the difference between total interstate capacity into California and typical total demand. There is sufficient overall pipeline capacity that PG&E is assured of only limited sales of Line 401 capacity. By itself, this factor indicates that PG&E might not have significant market power.The HHI is a measure of market concentration frequently used to assess competitive effects of mergers and acquisitions. The index does not predict anti–competitive behavior by a firm, but is a measure of the number of active participants in a market. For example, the HHI for interstate transportation of Southwest gas into California during 1995 was approximately 0.44, indicating 2.3 effective competitors in that limited market. n11 Looking only at this measure, we would conclude that SoCalGas and PG&E are dominant players at Topock. n12

n11 Recorded 1995 data taken from the "1996 California Gas Report," p. 19. At the border, SoCalGas transported 63.5%, PG&E transported 14.5%, and nonutilities transported 21.6% of Southwest gas delivered to California. The calculated HHI assumes four or five nonutilities, and includes Mojave pipeline gas. The number of effective competitors is the inverse of the HHI.

[*19]

n12 Issues relating to market power for SoCalGas will be examined more closely in A.96–10–038, the merger application of Pacific Enterprises and Enova.

Market power can be mitigated by regulation, but individual circumstances must be reviewed carefully. Regulation now has little impact on price competition between Line 401 and PG&E's Line 300, which delivers gas from Topock to PG&E's service territory. The lower limit for Line 401 prices is the cost of original system backbone facilities plus $0.02 per decatherm (Dth). n13 This leaves PG&E much latitude for discounting below the tariff rate of approximately $0.48/Dth. Service on Line 300 is sold at tariff rates; delivered gas costs are determined by upstream costs of Southwest gas and interstate pipeline service to the border. Incremental interstate service is typically over the El Paso pipeline using capacity that is under contract to PG&E but is not used by PG&E customers. PG&E sells that excess capacity under its capacity brokering program. PG&E sets minimum bids for brokered capacity, but claims that actual prices are often negotiated downward [*20] to rates lower than the posted minimums. Commission regulation includes reasonableness review of the negotiated transactions, as part of this proceeding, but such retrospective review has little effect on PG&E's market power. Taken as a whole, there seems to be little regulatory mitigation of PG&E's potential market power at Topock.

n13 D.94–02–042, 53 CPUC2d 215, 239 (1994).

In times when gas markets were isolated and regional, geographic constraints enhanced utility market power. Today we share PG&E's expectation that national gas markets will become increasingly integrated. Nonetheless, geographical factors have led to the emergence of Malin and Topock as the two principal entry points for transportation of gas into California. To a certain extent, geography has caused the present constraint on Line 400. We cannot simply find that increasing market integration prevents PG&E from exercising market power.

3.2 PG&E Market Power We draw no firm conclusions about PG&E's market power from the above simple measures [*21] of market behavior. We must dig deeper. In doing so, we should keep in mind the relationships among gas supply, transportation, and distribution costs. Currently, procurement costs are roughly $2.20/Dth, and local transmission and distribution costs are in the range of $0.75/Dth for noncore customers to $2.65/Dth for core customers, exclusive of public purpose and balancing account charges. By comparison, Line 401 firm service tariff rates are approximately $0.48/Dth, and as-available service is discounted below that. Interstate pipeline costs for Southwest gas are scarcely above variable costs, in the neighborhood of $0.10/Dth. The transportation rates disputed in this proceeding are important, but they are only a small fraction of burnertip gas costs. Therefore, the effects of gas transportation ratemaking on supply competition and California's pipeline infrastructure are crucial to our deliberations.PG&E and El Paso provide the best evidence on utility market power. PG&E makes many arguments about competition and pipeline markets, but they can be reduced to six principles. First, according to PG&E, markets are workably competitive if actual prices are substantially the same [*22] as prices that would result from full competition. No single party holds the power to control prices in the market. Second, PG&E cannot control prices or flows of gas at the California border, specifically at Topock or Malin. Third, theoretically, the existence of two market participants produces competition because one party can undercut prices that are set artificially high by the other party. In this way PG&E and SoCalGas compete against each other for sale of brokered interstate capacity into Topock. Fourth, gas supply competition in Alberta and burnertip competition in the end use market in California eliminate the possibility of market power in the transportation corridor between the two locations. Fifth, increased supply costs in Alberta caused by increased gas demand in California--enabled by construction of the expansion project by PG&E and PGT--are mitigated by consequent increased drilling and production in the supply basin. Sixth, overall gas cost reductions achieved in California subsume customer costs for new pipeline capacity. PG&E claims that California gas costs have dropped by $1.3 billion in the two years since Line 401 has gone into service, and costs in PG&E's [*23] service territory have dropped by more than $500 million.El Paso concludes that PG&E does have market power at Topock. El Paso believes the gas transportation market there fits the "dominant firm/competitive fringe" model. One or several firms are dominant price setters in the market, and other, smaller players operate within the fringe of the price-setting behavior of the dominant firms. In this case, SoCalGas and PG&E are the dominant firms. According to El Paso, these circumstances inevitably lead PG&E to use its market power in setting Line 401 prices. The effectiveness of PG&E's pricing strategy confirms that PG&E holds market power. El Paso believes that PG&E's minimum bids for brokered capacity held on the El Paso pipeline allow PG&E to control Topock prices and thereby control market rates for Line 401 capacity. El Paso criticizes PG&E's calculation of gas cost savings since Line 401 went into service, claiming that the observed cost reductions are due to factors like lower Canadian and San Juan basin supply prices and lower upstream pipeline costs. Most of PG&E's calculated cost savings began at least one year after Line 401 went into service. El Paso believes that PG&E's [*24] expansion project has caused at least $289 million in excess pipeline demand charges.We will not make a finding of fact that the transportation market at Topock follows the dominant firm/competitive fringe model strictly, but in our judgment that model is the best description of market dynamics there. PG&E's theoretical model of two-party competition is too limited. SoCalGas and PG&E control dominant shares of incoming interstate capacity, at least until their various contracts with interstate pipelines expire. Several factors give the utilities incentives to exercise price leadership at Topock. The market is concentrated, interstate pipeline capacity is in part substitutable, pipeline cost functions are similar, there are barriers to market entry, and overall demand for capacity is relatively inelastic. Price leadership is not necessarily collusive, but it gives SoCalGas and PG&E the opportunity to coordinate their behavior in ways that can lead to higher than competitive prices.We do not endorse PG&E's theory that supply basin competition and burnertip competition are sufficient to preclude market power in the transportation corridor between Canada and California. Because there [*25] are few supply alternatives to Canadian gas, and transportation costs are not large relative to fundamental supply price differences between Canada and the Southwest, PG&E may hold enough market power to limit end user access to the supply price benefits of Canadian gas.Considering all the evidence before us, we find that PG&E does hold market power at Topock and within California. PG&E may not be able to control gas prices at Topock, but to a substantial degree it can control flows through Topock and can sustain flows and therefore revenues on Line 401.

4. Conflict of Interest Several parties, led by TURN and El Paso, claim that PG&E has a conflict of interest in the operation of its gas system. TURN believes the conflict between shareholders and original system ratepayers arises from the Commission's "let the market decide" policy, under which Line 401 was certificated. PG&E concedes that Line 401 competes against brokered Southwest pipeline capacity. TURN points out that when Line 401 wins that competition, shareholders retain the revenues. When brokered capacity wins, revenues accrue to ratepayers as credits to PG&E's ITCS account. Because PG&E is responsible for marketing [*26] both of the competing products, it has a conflict of interest. TURN asserts that while PG&E would be expected to deny that it ever benefited from the conflict of interest, to deny its existence is simply not credible.El Paso concurs, and claims that the conflict pervades PG&E's operations. El Paso cites several examples: pursuit of subsidies for Line 401 through roll-in of the Line 401 revenue requirement with original system rates, setting of inflated minimum bids for brokered Southwest capacity, more extensive marketing efforts for Line 401 than for brokered capacity, PGT interruptible service discounting policies, backbone credit practices, inadequate consideration of gas supply diversity, and others. El Paso characterizes PG&E's decision to terminate service over the El Paso pipeline when current service agreements expire as the ultimate manifestation of the conflict of interest. El Paso believes the conflict of interest has led to stranded costs of $101 million through May 1995.PG&E argues that it has no conflict of interest in marketing its various holdings of pipeline capacity. According to PG&E, the term "conflict of interest" is no more than an inflammatory slogan unless [*27] it is coupled with the power to exploit the conflict, and marketplace competition prevents PG&E from doing so. PG&E claims that it has set up a competitive environment without creating incentives that favor Line 401 or El Paso capacity, and that it does not have the market power to take advantage of any perceived conflicts. Elements of PG&E's plan include arm's length operations by PGT, organizational separation of UEG and core procurement functions, and management vigilance against conflicts of interest.The Public Utilities Code neither defines conflict of interest nor prohibits conflicts of interest within utility management. Direct regulation of utility monopolies is in large part meant to control or neutralize conflicts of interest between shareholders and ratepayers. Faced with increased competition in utility industries, it remains our duty to authorize regulatory schemes which minimize such conflicts. Our goal in this proceeding is to provide PG&E with incentives to exercise its discretionary management functions in an evenhanded manner, so that ratepayers receive fair treatment as PG&E executes its fiduciary duties on behalf of shareholders. In the context of this proceeding, [*28] a conflict of interest arises when PG&E has a duty on behalf of shareholders to contend for outcomes which its duty to ratepayers requires PG&E to oppose. We do not presume that PG&E will represent ratepayers if that representation will be directly adverse to shareholder interests. In our view, such a conflict exists whenever there is a reasonable possibility that the utility will not exercise its discretion fairly. We need not determine whether a conflict is actual, in the sense that preference or harm is supported by direct evidence, or only gives an appearance of conflict.We concur with TURN and in part with El Paso in this dispute. Shareholders benefit when Line 401 serves market demand, and ratepayers benefit when brokered capacity serves the demand. By PG&E's own admission, the two services compete for the same loads. There is a reasonable possibility that PG&E acts preferentially in favor of shareholders when it markets the two services. Therefore, PG&E has a conflict of interest.It is more difficult to determine whether actual harm has ensued, as El Paso claims. In some circumstances, PG&E has clearly responded to the conflict of interest in favor of shareholders: through [*29] pursuit of rolled-in rates, by pricing Line 401 service to compete with brokered capacity, and by Line 401 marketing efforts that are more vigorous than capacity brokering efforts. PG&E's actions have been successful. In 1994, Line 401 operated at approximately 71% of its design capacity, or approximately 51% of as-available capacity after subtraction of firm service quantities. By comparison, in 1994 PG&E sold approximately 53% of unused El Paso capacity under its capacity brokering program. Monthly charges to the ITCS memorandum account rose from 1994 to 1995, and PG&E predicts that sales of brokered El Paso capacity will decline. At the same time, more than 90% of Northern California deliveries over Line 401 were found to be eligible for the backbone credit, thereby increasing revenues to PG&E shareholders. El Paso's vehement reaction to loss of PG&E as a pipeline customer is understandable, but we cannot agree with El Paso that termination of service to PG&E is the ultimate manifestation of the conflict of interest.We will consider the consequences of PG&E's future conflicts of interest in review of the **Gas Accord.**

5. Gas Accord The full **Gas Accord** document is 87 pages [*30] long; it is reproduced in Appendix B to this decision. As required by Rule 51.1(e) of the Commission's Rules of Practice and Procedure, we can approve the settlement only if it is reasonable in light of the whole record, consistent with law, and in the public interest. We must make an independent determination on these issues rather than simply deferring to the number of parties supporting the settlement.

5.1 Elements of the Gas Accord In a nutshell, the **Gas Accord** would: (1) unbundle gas transportation service into specific paths, with assignment of capacity to core customers, and partial roll-in of Line 401 costs into Line 400 rates; (2) offer various service options to existing Line 401 firm service customers; (3) include core procurement costs in rates based on two CPIM proposals; (4) settle contested issues regarding ITCS amortization, Line 401 capital costs, and recent gas reasonableness reviews, including PG&E's federal district court challenge to one of our reasonableness reviews; and (5) set transmission , and storage rates for the **Gas Accord** period through December 31, 2002.In the **Gas Accord** (p. 68), PG&E has specifically agreed that if the **Gas Accord** is approved [*31] without modifications or with modifications acceptable to PG&E and DRA, PG&E would "permanently forego recovering from its ratepayers any of the disallowance ordered by Decision 94-03-050, which has been (or will be) refunded to ratepayers, notwithstanding the outcome of its pending lawsuit in Federal District Court (Civil No. C-94-4381 WHO)." n14 On page 8 of PG&E's April 23, 1997 comments on the ALJ's proposed decision, PG&E also explicitly represented to the Commission that with the approval of the **Gas Accord,** PG&E would "forego appeals of other Commission decisions, such as the 1988–90 Gas Reasonableness Decision (Re Pacific Gas and Electric Co., D.94–03–050; 53 CPUC 2d 481 (1994)), presently on appeal to the Federal District Court (Civil No. 94–4381 SBA)." n15

n14 In ORA's October 4, 1996 reply comments on the **Gas Accord** settlement (p. 17), ORA explained that this provision "would assure that ratepayers would retain the $90 million (plus interest) disallowance ordered by the Commission..." A substantial amount of this disallowance resulted in a refund from PG&E to its own UEG and the **Gas Accord** states that this amount would be credited to PG&E's Energy Cost Adjustment Clause (ECAC) balancing account. In light of the passage of AB 1890, subsequent to the August 21, 1996 filing of the **Gas Accord,** the amounts in the ECAC balancing account would not inure to the benefit of the PG&E's ratepayers, as DRA had intended, unless the UEG's share of the disallowed amounts was refunded from a different account. However, we have already resolved this matter in D.96–12–025, D.96–12–026, and D.96–12–027 issued on December 9, 1996, where we held that disallowed amounts must be credited to an Electric Deferred Refund Account (EDRA), instead of PG&E's ECAC, and then refunded to PG&E's electric ratepayers. Our approval of the **Gas Accord** does not alter our rulings in D.96–12–025, D.96–12–026, and D.96–12–027, and, therefore, PG&E must adhere to our explicit ruling in D.96–12–026, which already required the UEG's share of the $90 million (plus interest) disallowed amounts to be returned to electric ratepayers through the EDRA, and to our general requirement in D.96–12–025 that any and all settled disallowed amounts must be returned to ratepayers through the EDRA rather than be credited to PG&E's ECAC.

[*32]

n15 In PG&E's June 18, 1997 comments on the Proposed Alternate Order, PG&E incorrectly asserts that the Proposed Alternate Order assumed that under the **Gas Accord,** PG&E would "forego" its federal district court challenge. However, the Proposed Alternate Order did not state this as an assumption; the Proposed Alternate Order referenced PG&E's April 23, 1997 comments for PG&E's explicit representation in this regard.

Presumably, DRA had made a concession to PG&E as a quid pro quo for PG&E's commitment to forego its federal court case. Accordingly, our approval of the **Gas Accord** is based upon PG&E's following through on all of its commitments, including PG&E foregoing its federal district court challenge as represented in PG&E's April 23, 1997 comments (at p. 8). We are therefore explicitly stating in our Ordering Paragraph that our approval of the **Gas Accord** is based, in part, upon PG&E's commitments to permanently forego recovering from its ratepayers any of the disallowance order by D.94–03–050 which has been (or will be) refunded and to forego its appeal of the D.94–03–050 to the Federal [*33] District Court (Civil No. 94–4381).**Gas Accord** service paths would begin at Malin, Topock, or California facilities. Delivery points, generally, would be labeled on–system (within the PG&E service territory) and off–system (outside the service territory). Core reservations would be approximately 600 MMcf/d on Line 400 and 150 to 600 MMcf/d on Line 300, the latter varying seasonally. There would be no crossover ban and no balancing account to guarantee PG&E revenues. Rates for noncore distribution service would be seasonally differentiated.Current Line 401 firm shippers would face rates based on $736 million of Line 401 capital costs. Shippers could choose among three options: (1) Accord service, available if the shipper waives Universal Terms of Service (UTS) rights; (2) G–XF service, which is much like present service but with UTS rights limited to firm service; or (3) individually negotiated options, subject to Commission approval.The first CPIM, applicable to the period from June 1, 1994, through December 31, 1997, incorporates a core procurement price formula agreed upon by PG&E and DRA in A.94–12–039, PG&E's current CPIM application. From January 1, 1998, through December [*34] 31, 2002, the formula would be modified to include daily sequencing in place of monthly price weightings, a Topock price index in place of Southwest basin prices, limited recovery of Transwestern pipeline demand charges, and other terms.Several general rate case and gas reasonableness issues would be settled. Line 401 initial capital costs of $736 million would be included in Line 400/401 rolled–in rates and Line 401 incremental rates. PG&E would absorb 50% of outstanding noncore ITCS costs, 100% of core ITCS costs, the backbone credit account balance, and $3.7 million of contested 1988–1990 costs. PG&E would not be responsible for any "statewide ITCS" costs, which are essentially Southern California stranded costs caused by Line 401. Commission proceedings regarding PG&E's decision to construct and related Rule 1 allegations would be terminated.Most core and noncore transportation rates would be reduced from current values, but would be subject to 2.5% annual escalation from 1998 through 2002. Utility intentions about ratemaking treatment of the side deal payment from Edison to PG&E are not in the record.

5.2 Features Supporting Approval The **Gas Accord** has several attractive [*35] features. First, the settlement has the support of a broad spectrum of active parties. ORA is a government entity that represents the interests of all customers, and CIG, CMA, and CLFP represent noncore customers specifically. With the support of Edison and SDG&E, which came after the settlement was reached, a majority of current firm shippers on Line 401 have joined the **Gas Accord.** Other endorsements are the result of bilateral agreements, or side deals, between PG&E and individual parties. The side deals generally settle issues of reduced interest to other parties. For example, the sale of pipeline equity shares to SMUD is very important to SMUD itself, but is not of compelling interest to other parties.Second, the **Gas Accord** would unbundle PG&E's gas transmission system into separate services. This would improve flexibility and customer choice among noncore service options, and would allow a closer match of transportation rates with facilities used to provide service. With unbundling comes a logical reliance on embedded costs in calculating rates. Direct comparison between marginal cost and embedded cost methods has not been the focus of this proceeding, but in general the matching [*36] of rates and facilities is enhanced by embedded cost ratemaking. Marginal costs (after adjustment for embedded cost revenue requirement) can be used to allocate utility costs fairly among customer classes, but resulting rates can be very sensitive to initial marginal cost decision choices. As service is unbundled into manageable components, cost allocation problems and the need for marginal cost allocation procedures are diminished. PG&E responsibility for the transmission revenue requirement is also a desirable element of the proposed unbundling scheme, with attendant elimination of balancing accounts. It would assist in protecting original system ratepayers from costs or risks associated with Line 401, as PG&E promised in the certification proceeding.Third, the **Gas Accord** would resolve difficult issues in various Commission proceedings. There is no common yardstick for comparing administrative benefits against the risk that issues might be settled unfairly or inefficiently. That is why support from parties with diverse interests is important. Nonetheless, settlement of contested issues in arduous proceedings has value for the Commission and the parties. In the Line 401 general [*37] rate case, the **Gas Accord** would settle issues regarding capital costs, operations and maintenance expenses, receipt point capacity allocation, the crossover ban, ITCS amortization and past conflicts of interest, backbone credit balancing account amortization, core capacity reservation, and the decision to construct. In other proceedings, the **Gas Accord** would settle CPIM issues, gas reasonableness review disputes, and details of PG&E's core aggregation program. Along with resolution of contested issues comes the benefit of rate certainty during the **Gas Accord** period.Fourth, PG&E's divestiture of gas gathering facilities would be a step toward a more rational market structure. It would put gas gathering assets in the hands of parties most affected by their management.Other beneficial features of the **Gas Accord** include core aggregator flexibility, phasing out of PG&E's core subscription program, and assignment of Expedited Application Docket (EAD) contract shortfalls to PG&E. Core aggregator unbundling and the equity sale to SMUD, now underway in separate applications, are benefits of the **Gas Accord** process but are not incremental benefits of the outcome. They will go forward independent [*38] of Commission approval or rejection of the **Gas Accord.**

5.3 Features Opposing Approval In our estimation, the most troublesome feature of the **Gas Accord** is its failure to resolve or mitigate PG&E's basic conflict between customer and shareholder interests. PG&E's position is that the **Gas Accord** resolves alleged conflict of interests. We disagree. The Canadian price advantage over Southwest supplies creates the opportunity to gain economic value on northern path pipelines. PG&E's present conflict of interest, accompanied by utility market power within California, results in a transfer of economic value from Southwest producers to Canadian producers, PG&E, and holders of pipeline capacity north of California. El Paso argues that PG&E's minimum bids for brokered capacity have raised Topock prices, thereby transferring value from end users to northern interests. We cannot be certain this is true, as PG&E claims that minimum bids do not affect final capacity brokering prices. At a minimum, ratepayers are harmed by loss of capacity brokering credits. PG&E argues that El Paso receives its full demand charges whether PG&E's contract capacity is used or not, and ratepayers as a whole [*39] are not harmed. PG&E is looking at the wrong group of ratepayers. It is true that total revenues paid to El Paso by ratepayers are unaffected by capacity brokering, if one assumes that incremental shippers on Line 401 that cause the loss of capacity brokering credits are also PG&E customers. However, the set of all ratepayers except the incremental shippers suffers a net loss of the forgone capacity brokering credits. That value is transferred to PG&E shareholders and northern interests.Under the **Gas Accord,** loss of current capacity brokering credits would not be a major problem because PG&E's contracts with El Paso will expire at the end of 1997. However, if PG&E controls future pipeline prices or revenues for supplies from Canada and the Southwest, PG&E would retain its conflict of interest. The transfer of benefits from noncore end users to PG&E and northern interests might even be exacerbated. As long as the Canadian supply price advantage endures, which seems reasonable for the **Gas Accord** period, end user benefits will be linked to the delivered price of Southwest gas. Currently the market value of unused pipeline capacity from the Southwest is very small, equal to variable [*40] costs plus a contribution to fixed costs sufficient to encourage El Paso and PG&E to sell idle capacity. Under the **Gas Accord,** the average Topock to on–system rate would be approximately $0.165/Dth. n16 The Line 300 rate is roughly $0.15/Dth higher than market value, resulting in a transfer of economic value from end users to northern interests, even if the present balance between Canadian and Southwest gas sales to the noncore is maintained. We do not know which entities would receive those benefits, but value tends to migrate toward holders of constrained capacity. Annual harm to end users could be in the tens of millions of dollars. There would also be a small efficiency loss, relative to market prices for Line 300.

n16 Appendix B, Accord Rates, Table 2, p. 71. Topock to On–System rates would be $0.145/Dth in 1997, $0.155/Dth in 1998, $0.164/Dth in 1999, $0.169/Dth in 2000, $0.172/Dth in 2001, and $0.175/Dth in 2002. These rates include costs for Line 300 and other backbone and local transmission facilities. Malin to On–System rates for Line 400/401 are $0.238/Dth in 1997, $0.253/Dth in 1998, $0.265/Dth in 1999, $0.267/Dth in 2000, $0.269/Dth in 2001, and $0.269/Dth in 2002.

[*41] Under the **Gas Accord,** PG&E would retain its preference for Canadian noncore supplies, because PG&E has higher rates and would receive greater revenues from increases in throughput on its Line 400/401 in lieu of throughput on its Line 300, and PG&E's affiliate, PGT, would also receive greater revenues from increases in throughput on PGT in lieu of throughput on Southwestern interstate pipelines. PG&E could exert its market power to maximize California customer revenues by discounting service beginning at Malin (over rolled–in Line 400/401, if capacity is available) instead of service beginning at Topock (over Line 300). This unfair competition could cause higher burnertip gas prices in California and would harm Southwest producers and pipelines, to the eventual detriment of California end users through loss of supply diversity. Indeed, PG&E's incentive to discount only its Canadian path rates (i.e. from Malin) and not its Southwestern path rates (i.e. from Topock) could also result in unduly discriminatory discounting practices and in unfair competition between Canadian suppliers and Southwest suppliers. We cannot evaluate the benefits of supply diversity in dollar terms, but we should [*42] promote diversity by promoting fair competition among supply sources.We cannot anticipate all future PG&E and market responses to PG&E's future conflict of interest, in the same way we did not predict backbone credit exchange agreements and other market reactions to earlier Commission decisions. However, we are convinced that under the **Gas Accord** PG&E would have an incentive to use market power in ways that could harm California end users and Southwest interests. Acting to keep Line 300 rates high is only one example. The conflict of interest could also extend to PG&E's use of its contracted Transwestern pipeline capacity.Second, rolled–in rate treatment for Line 401 and the proposed path–specific unbundling scheme 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. n17 The Commission confirmed that none of the costs of Line 401 would be allocated to original system ratepayers. n18 When PG&E determined the scale and timing [*43] 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. Path–specific unbundling would further obscure the incremental nature of Line 401.

n17 Exhibits 532 and 533.
n18 D.90–12–119, Finding of Fact 41, 39 CPUC2d 69, 152 (1990).

Third, as TURN argues, 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 [*44] 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.Fourth, the **Gas Accord** holds few direct economic benefits for core customers. The **Gas Accord** offers immediate short–term rate reductions, but they are offset by 2.5% annual escalation through 2002. The settled escalation factor may be a reasonable estimate of general inflation, but it seems to exclude productivity opportunities, and it applies to entire transmission rates. Escalation is not restricted to cost elements that are generally subject to inflation. The embedded costs of existing pipelines are driven by sunk capital costs, not capital additions or operations and maintenance costs that might be affected by inflation.See Appendix C to this decision for a simplified present value analysis of core and noncore benefits. The analysis shows that net core costs would be 1.2% lower under the **Gas Accord,** and net noncore costs would be 7.7% lower under the **Gas Accord.** In this instance we [*45] are principally concerned about effects on the core, because noncore parties have agreed to the **Gas Accord,** and noncore benefits are more substantial. The ORA represents all customers, but no party representing only core customers has endorsed the **Gas Accord.**We should comment on PG&E's characterization of direct economic benefits. PG&E offers to forgo $283 million of utility costs. n19 These customer benefits are not all assignable to the **Gas Accord,** but are concessions relative to PG&E's positions in the underlying proceedings. It is possible that full litigation of the issues would result in disallowances that are higher than $283 million. The total is, however, within the overall range of dispute.

n19 The total consists of $74 million of Line 401 capital costs, $160 million of ITCS undercollections, $25 million of backbone credits, $20 million of EAD shortfalls over the **Gas Accord** period, and $3.7 million of reasonableness review payments.

Fifth, we are concerned that the **Gas Accord** does not fairly reflect [*46] the interests of core customers or Southwest producers and pipeline companies. PG&E has settled with: (1) noncore customers, (2) ORA as a representative of all customers, (3) most Line 401 firm shippers, and (4) individual parties with narrow interests. Noticeably absent are TURN, El Paso, and New Mexico. The fairness of representation in a settlement is a matter of judgment, but the exclusion of PG&E's competitors is especially troubling. We disagree with the suggestion of CIG and CMA that we should not expect competitors to come together in settlements. In comments to the proposed decision, PG&E describes the **Gas Accord** as an all-party settlement, and characterizes **Gas Accord** signatories as "the market itself." The claims are overblown. Representatives of core customers, noncore customers, and Southwest interests oppose the **Gas Accord.**Sixth, we are uncertain about the disposition of Edison's $80 million termination payment to PG&E. Edison may seek to include in rates the cost of its payment, and PG&E may intend to retain the payment instead of using it to reduce the rolled-in revenue requirement for Line 400/401.

5.4 Conclusion We will approve the **Gas Accord.** In our [*47] judgment, the persistence of PG&E's conflicts of interest can be reasonably mitigated by future Commission proceedings concerning matters not specifically addressed by the **Gas Accord** and by our imposition of a discounting rule in this order. With continued Commission oversight concerning PG&E's conflicts of interest and with certain policy clarifications and the discounting rule discussed in Chapter 6 below, we find that the **Gas Accord** is reasonable in light of the whole record, consistent with law, and in the public interest.We are impressed with the breadth of support for the **Gas Accord.** PG&E, utilities and other transportation customers of Line 401, and representatives of both core and noncore customers have settled many difficult economic and regulatory issues. Asset-based unbundling of PG&E's gas transportation service would be preferable to the settled path-based unbundling, but PG&E's acceptance of responsibility for revenue requirements without balancing account treatment offsets that defect. 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. Direct benefits to the core [*48] are smaller than benefits to the noncore, but core customers will benefit from seasonal reservations of pipeline capacity and access to Line 400 service at vintaged rates. All customers will benefit from regulatory certainty during the **Gas Accord** period, and from resolution of ITCS and backbone credit issues, as discussed in Chapter 8 herein.Pursuant to Rule 51.1(e) of the Commission's Rules of Practice and Procedure, we specifically find that the **Gas Accord** is reasonable in light of the whole record, consistent with law, and in the public interest, because it represents a significant improvement over PG&E's currently bundled rates and services, provides PG&E's customers with greater flexibility and competitive alternatives, and resolves rate issues within the zone of reasonableness such that we can find PG&E's rates to be just and reasonable. It is not clear that PG&E's rates would be as favorable for its ratepayers through continued litigation as the rates provided in the **Gas Accord,** and, as discussed elsewhere in this decision, the resolution of the rate issues in the **Gas Accord** represents a fair accommodation of the various arguments in the litigation in the proceedings.The problems [*49] we have identified with the **Gas Accord** primarily focus on how the **Gas Accord** does not go far enough in mitigating PG&E's conflicts of interest and the resulting unfair competition concerning PG&E's marketing of Line 400/401 and use of Line 300 and in mitigating potential conflicts of interest in PG&E's procurement of gas for its core customers. 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 issues 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 [*50] not misinterpret this decision and to impose a discounting rule in this order to address PG&E's marketing conflicts of interest. Nothing in the **Gas Accord** gave PG&E complete discretion in its discounting of its services, and we will therefore impose a discounting rule which we believe will mitigate PG&E's conflict of interest (between its marketing of Line 400/401 services and use of Line 300) and provide for fairer competition between shippers accessing Canadian, California, or Southwest suppliers.We will continue to scrutinize PG&E's procurement of gas for its core customers and will not hesitate to impose penalties or disallowances if PG&E's CPIM proves to be inadequate in protecting PG&E's ratepayers from PG&E's conflicts of interest. We would note in this regard, that our approval of the **Gas Accord** in no way prejudices our consideration or approval of rules addressing affiliate abuse issues, or our consideration or determinations concerning PG&E's procurement practices based upon our review of the reports PG&E is required to file under the **Gas Accord.** We also intend to go forward with our Natural Gas Strategic Plan to consider and implement unbundling polices beyond the unbundling [*51] in the **Gas Accord,** as well as to consider other means to produce a more competitive gas market for all classes of utility customers.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, and we further clarify ambiguities concerning other issues in the **Gas Accord.**Accordingly, we find that the **Gas Accord** is in the public interest subject to the discounting rule in this order and the Commission's continued oversight in subsequent Commission proceedings of PG&E's rates, services, and practices.

6. Related Issues In approving the **Gas Accord,** we must clarify our intentions about several issues related to PG&E's gas transportation service.

6.1 Decision to Construct We accept the **Gas Accord's** resolution of reopened proceedings on PG&E's decision to construct Line 401, but we must review the record in order to address deceit claims made by Norcen.

6.1.1 Res JudicataPG&E submits that there is no lawful basis to reopen the finding of reasonableness in D.94–02–042. PG&E cites the legal doctrine of res judicata, under which a matter decided by a court of competent jurisdiction [*52] is decided finally.In reply briefs, TURN, Norcen, and Edison counter PG&E's res judicata argument by citing Commission authority under Public Utilities (PU) Code § 1708. Edison has since disavowed its position, but its legal arguments are part of the record.We reject PG&E's argument that reopening the decision to construct is unlawful. PU Code § 1708 specifically allows the Commission to rescind, alter, or amend any of its orders or decisions after notice and opportunity to be heard. Although res judicata rules apply generally to Commission orders, they should be administered more flexibly than in the judicial system. n20 In the present circumstance, the discovery of new evidence provided ample justification for the reopening.

n20 Arakelian Farms, Inc. v. Agricultural Labor Relations Bd., 49 Cal. 3d 1279, 1290 (1989).

6.1.2 Positions of Parties According to PG&E, the existence of the McLeod memo was revealed in earlier cross–examination, and PG&E did not mislead the Commission or the parties by not [*53] volunteering its contents. The McLeod memo reveals a set of reasons for building the expansion project that are somewhat different from the reasons set forth in PG&E's testimony, but PG&E claims its testimony sets forth the actual reasons that management made its decision, not the reasons supported by PG&E staff in the memo. PG&E argues that Norcen's Rule 1 allegations are not based on new evidence, but are only another version of a contract suit against PGT now underway in a different forum; Norcen's attempt to rescind its contract for firm service on the PGT portion of the expansion belongs in court, not before the Commission.In laying a foundation for its deceit claim, Norcen makes several arguments against the reasonableness of PG&E's decision to construct. First, Norcen asserts that there was not sufficient market demand for Line 401 to avoid underrecovery of the revenue requirement. Instead, PG&E relied on the commitments of shippers with signed contracts on the PGT portion of the expansion. Those shippers would "of necessity" use Line 401 for transportation service in California. n21 Norcen points out that the reasons for the recommendation to build contained in the McLeod [*54] memo are different from the reasons in PG&E's earlier testimony. The McLeod memo emphasizes the irrevocable commitment of upstream shippers, PG&E's "first mover" advantage over a pipeline proposed by Altamont Gas Transmission Company (Altamont), and loss of a $44 million supplemental payment from TransCanada PipeLines Ltd. (TransCanada) if the expansion project was canceled. Norcen's witness Sheldon Reid testified that Norcen never intended to take Line 401 service, but signed a contract for PGT service in order to deliver Canadian gas to Malin. n22 Norcen assumed that downstream shippers taking that gas would have access to rolled–in rates in California. Norcen accuses PG&E of sharp business practices because PG&E surreptitiously planned to pursue the crossover ban at the time Norcen signed its PGT contract.

n21 Exhibit 455, Bates 000679.
n22 Tr. 70:9093.

TURN argues that PG&E unreasonably went forward with the expansion based on a view of market demand rooted in PG&E's attempts to avoid or reverse two Commission [*55] requirements: incremental ratemaking, and firm contracts for Line 401 capacity. El Paso agrees with Norcen that the Altamont threat and the TransCanada payment were major drivers of the decision to construct. New Mexico claims that PGT subscriptions did not necessitate Line 401 loads, because PG&E had notified PGT shippers that lack of market support would result in reduced physical facilities on the California side. New Mexico argues that sufficient firm contracts for Line 401 service were not in place, that supply basin economics did not support the project, and that Altamont and TransCanada considerations are insufficient for a finding of reasonableness. CAPP concurs that market support for the expansion was inadequate, and asks for Commission findings that will assist individual shippers entrapped by PG&E into PGT capacity commitments.

6.1.3 New Evidence We are faced with new evidence that falls into three categories: (1) the McLeod memo and supporting documents and testimony; (2) discovery documents and testimony presented by Norcen, El Paso, and TURN; and (3) information about stranded cost risks addressed in A.89-04-033, the Line 401 certification proceeding. We have [*56] carefully reviewed this evidence, but we have not attempted to reinterpret or recharacterize evidence taken during earlier phases of this proceeding.The McLeod memo sets forth reasons to construct Line 401 that clearly differ from reasons in PG&E's earlier testimony. During 1993 hearings, PG&E presented five related factors in support of its October 25, 1991, decision to commence construction of the expansion project: n23 (1) upstream PGT capacity was fully subscribed, confirming market intent to support the overall expansion project; (2) more than 80% of Line 401 capacity was subscribed by firm shippers, although their commitments included various termination rights; (3) PG&E proceeded only after contracts with anchor shippers Edison and SDG&E were fixed; (4) there was no shipper interest in Line 401 capacity that might be less than upstream PGT capacity; and (5) Canadian gas at the northern end of the pipeline was abundant and competitively priced. The McLeod memo does not present its reasons as succinctly, but summarizes three: (1) although there was uncertainty about rate design issues before this Commission, revenue recovery was not an issue because California shippers were irrevocably [*57] contracted on upstream pipeline segments; (2) target throughputs were attainable, due to sound economics and full subscription of PGT capacity; and (3) deferral of the project was an ineffective option because it would increase construction and financing costs. The memo goes on to discuss project economics, management of regulatory risk, and competitive positioning. The project economics are supported in the attached study by McKinsey & Company. Regulatory risks resided primarily on the California segment of the pipeline. The expansion's competition was the Altamont project. Cancellation risked loss of the TransCanada payment.

n23 Exhibit 6, p. GJB-7.

Notwithstanding this discrepancy in PG&E's testimony, we will not change our ruling on the reasonableness of PG&E's decision to construct its expansion. M&E was placed at risk for any revenue shortfalls due to the undersubscription of its Line 401, and, therefore, PG&E's shareholders had to absorb the revenue shortfalls to the extent that Line 401 was not fully subscribed, [*58] was not fully utilized, or was utilized but at discounted rates. Moreover, nobody forced PGT's expansion shippers to sign firm service agreements with PGT. PG&E apparently believed that the full subscription to PGT's expansion inevitably would result in market support for PG&E's Line 401.We are concerned, however, that PG&E might not have testified in our previous proceeding as to the whole truth when it omitted in its 1993 testimony mention of competition from Altamont or the TransCanada payment and when it mischaracterized the level of firm commitments to its Line 401.In D.94-02-042, the Commission found the decision to construct to be reasonable because the certification decision did not assign stranded costs to shareholders, other Commission decisions protected shareholders from indirect costs of stranded capacity, and discounting limits would minimize stranded costs. n24 New evidence on actual market transactions show that discounting limits do little to minimize stranded costs. The limits are low enough--approximately $0.08/Dth--that PG&E retains a strong incentive to favor Line 401 sales over brokering of unused Southwest capacity, resulting in increased ITCS obligations [*59] to original system ratepayers. n25 Yet, in A.89-04-033 itself and in the subsequent amended application, PG&E assured the Commission: n26

> "The cost of the service provided by the Expansion Project will cover the incremental costs of the new facilities and will not include any costs of PG&E's existing gas transmission system. Under this cost allocation

proposal, PG&E's existing gas customers will be insulated from any risks associated with the Expansion Project, unless they also receive service on the Expansion Project." (Emphasis added.)* * *

"Under this incremental cost allocation proposal, PG&E's existing utility gas customers who do not also receive service over the Expansion Project are insulated from any costs or risks associated with the Expansion Project." (Emphasis added.)

n24 D.94-02-042, Finding of Fact 11, 53 CPUC2d 215, 248 (1994).
n25 Exhibit 228.
n26 Exhibits 532 and 533.

Two PG&E witnesses testified to the meaning of the promise. The first witness was Richard Clarke, PG&E's Chairman [*60] of the Board and Chief Executive Officer in 1989, when PG&E filed A.89-04-033. In response to a question by the ALJ, Clarke testified: n27

Q Does it mean that existing gas customers will be insulated from risks associated with stranded costs?

A I don't see that here. But I guess to pursue, if stranded can be easily defined and distinguished from slack, then I assume that would also flow.

Slack capacity is capacity in excess of demand needed to generate the benefits of competition. Stranded capacity is unused capacity beyond slack capacity.

n27 Tr. 72:9488, regarding Exhibit 532.

The second witness was Geoffrey Bellenger, PGT's Manager of Gas Supply and Regulatory Affairs in 1989. The quoted excerpts from A.89-04-033 were prepared under his supervision. Bellenger noted that the first excerpt is found under the heading "Financing and Rates" and goes to the cost allocation proposal in the application. In response to questions by the ALJ about specific meaning, Bellenger testified: n28

A And I think what it's [*61] saying is that PG&E existing customers will not have to pay any of the costs of the pipeline expansion project.

And in this context, in 1989, it can only be talking about the direct costs of the project—the costs that are used to establish the revenue requirement and the rates—and that the risks associated with the project would be PG&E's ability to recover that revenue requirement in the market.

Q Why do you think it's limited to direct costs?

A Because if there was any indication at the time from the Commission, or anywhere else, that PG&E would be exposed to indirect costs, I just have to believe that there would have been something in the application to address that issue.

And my own personal recollection: At the time we put this together, there was no such indication. And this was a traditional approach to financing and ratemaking; and this was to give the Commission the assurance that the direct costs of the project would not be borne by the existing ratepayers.

n28 Tr. 73:9586, regarding Exhibit 532.

[*62] In D.94-02-042, the Commission found that shareholders should not bear the costs of stranded capacity on interstate pipelines or PG&E's original pipeline system. It did so in large part because the certification decision did not explicitly assign indirect stranded costs to shareholders. The Commission stated: n29

"In D.90-12-119, we could also have assigned to shareholders the costs of stranded capacity, but we did not.

To make such an assignment now would unfairly impose a new performance standard on PG&E."

n29 D.94-02-042, 53 CPUC2d 215, 227 (1994).

We now see that this performance standard was not new, but was embodied in the explicit promises made by PG&E in A.89-04-033. PG&E stated unequivocally that original system ratepayers would be "insulated from any costs or risks associated with the Expansion Project." PG&E witness Bellenger attempts to limit those risks to the direct costs of Line 401, on the grounds that PG&E had no notice to the contrary. We cannot accept this limitation. The meaning of the risk [*63] protection statements in A.89-04-033 is unambiguous. No interpretation is necessary. PG&E's Chairman of the Board at the time admits as much, as long as stranded capacity is distinguished from slack capacity.PG&E's assumption of revenue requirement risks and agreement to bear ITCS costs under the **Gas Accord** is a logical consequence of its earlier commitments. Thus, while we will not change our finding on PG&E's reasonableness to construct its expansion, we believe that PG&E should bear more responsibility for its risks and stranded costs than it has in the past and we find that the **Gas Accord** provides a reasonable resolution of this issue.

6.1.4 Deceit Claim Norcen asks for specific relief in its dispute with PG&E. Norcen seeks: (1) findings that PG&E's decision to construct the expansion was unreasonable, and that PG&E deceived the market into becoming captive to PG&E's designs, which were antithetical to market signals; (2) use of 95% load factors in Line 401 rate calculations; (3) an order requiring PG&E to accept permanent release of Norcen's contracted capacity on PGT and Canadian pipelines, without adverse economic consequences to PG&E ratepayers; and (4) an order setting [*64] hearings to determine the amount and extent of stranded costs caused by PG&E, and eventual removal of stranded capacity from rate base and removal from rates of the costs of stranded interstate capacity.These seem to be the key events within a massive record: On January 22, 1991, FERC issued the decision that allowed shippers to use Malin as a delivery point on the PGT portion of the expansion. On January 29, 1991, PGT wrote potential shippers a letter assuring them that PGT would keep them informed as events unfold at FERC and the Commission. n30 On February 20, 1991, PG&E Vice President John Keyser wrote PGT President Stephen Reynolds to warn that failure to contract for firm capacity on the PG&E segment of the expansion would result in California physical facilities that do not match PGT expansion capacity. n31 On the same day, PG&E transmitted a package of documents—including the Keyser letter—to prospective shippers. n32 Norcen (or Bonus Energy, Inc., Norcen's predecessor in interest) received the Keyser letter. On February 26, 1991, Reynolds wrote Commission President Patricia Eckert to propose, among other actions, what is now known as the crossover ban. n33 On April 23, [*65] 1991, PG&E filed with FERC a pleading seeking the crossover ban. n34 Sheldon Reid, now Vice President of Norcen, testified that Norcen did not receive either a copy of the FERC pleading or news of its existence before April 25, 1991, when Norcen signed its firm service contract with PGT. n35

n30 Exhibit 521.
n31 Exhibit 476.
n32 Exhibit 480, Attachment 2, ref. Item 8.
n33 Exhibit 477.
n34 Exhibit 498.
n35 Tr. 69:9007.

Norcen asserts that the failure of PG&E or PGT to inform Norcen of utility intentions to pursue the crossover ban, in the face of Norcen's intention not to take service on Line 401, was part of a covert campaign to force PGT shippers to use Line 401 for deliveries to Northern California. According to Norcen, such strong-arm efforts were deceitful and contrary to shipper intentions, and they justify the requested relief. CAPP supports Norcen's request for findings of impropriety, but concedes that the Commission is not empowered to administer the requested contract remedies.PG&E and [*66] PGT argue that Norcen's allegations of deceit or breach of promise are unsupported by the facts. They point to a Norcen internal memorandum dated February 5, 1991, which expresses concern about PGT's "stated position on 'no cross-over' between the new PGT Expansion and the new PG&E Expansion at Malin...." n36 The memo suggests that Norcen knew of PGT's intent before it signed its PGT contract. PG&E and PGT claim the dispute between Norcen and PGT is a contract matter that should be decided by the courts, not the Commission. PG&E notes that the alleged misdeeds by PG&E and PGT occurred prior to execution of Norcen's contract with PGT. Therefore, contract principles cannot be applied.

n36 Exhibit 480, Attachment 5.

We will not make the findings sought by Norcen. Although we are concerned about some of PG&E's actions, we will not grant Norcen the relief it seeks. At most, PG&E and PGT sent mixed signals to shippers. The February 5, 1991, Norcen memorandum clearly shows that Norcen understood PGT's position regarding crossover. [*67] The February 20, 1991, letter from PG&E to PGT indicates that PG&E's solution to mismatched demand for PGT and PG&E service was to build less capacity in California. In a deposition before Norcen attorneys, PGT Senior Vice President Paula Rosput understood that some successful PGT bidders might not seek to contract for firm capacity south of Malin. n37 Yet PGT's Manager of Gas Supply and Regulatory Affairs testified that there was no shipper interest in Line 401 capacity that might be less than upstream PGT capacity. The PG&E steering committee endorsed that assessment in October 1991, six months after the PGT portion was fully subscribed, despite the fact that firm capacity commitments had not filled Line 401. Obviously PG&E did not carry out its threat to build less than matching capacity south of Malin. Did PG&E interpret shipper reluctance to sign Line 401 contracts as a bluff rather than a lack of interest? Did PG&E really believe those shippers would eventually contract for matching Line 401 capacity "of necessity?" If so, what was the point of the warning in the February 20, 1991, letter regarding lower than matching capacity in California? We do not have good answers to these [*68] questions, but we do not intend to interpret the mixed signals sent during contract negotiations.

n37 Exhibit 537, pp. 191-194.

Turning to other relief requested by Norcen, load factors within rate calculations are resolved by the **Gas Accord.** We will deny Norcen's request for an order to accept release of Norcen's PGT capacity. As a policy matter, Norcen's contract dispute with PGT belongs in the court where it began, not before the Commission. We need not address the jurisdictional arguments of PG&E and PGT. Finally, it is not necessary to convene hearings on stranded costs.

6.2 Rule 1 Allegations In the motion that led to the reopening of the decision to construct, Norcen and TURN recommend that the Commission assess whether PG&E's nondisclosure of the McLeod memo violated Rule 1 of the Commission's Rules of Practice and Procedure. Norcen and TURN submit that if PG&E had properly disclosed the McLeod memo, there is a strong expectation that the Commission would alter its findings that PG&E's decision to [*69] construct was reasonable.Rule 1 is a code of ethics that requires any person appearing before the Commission to agree "never to mislead the Commission or its staff by artifice or false statement of fact or law." Such misleading conduct can include omission of facts that might influence a Commission decision, if the omission is intentional or caused by reckless or grossly negligent actions. In the present context, reckless behavior can be acts or omissions that are heedless or inattentive to material consequences. n38

n38 Black's Law Dictionary, Revised Fourth Edition, p. 1435 (1968).

We perceive two possible areas of misbehavior. First, PG&E may have misled the Commission in PG&E's testimony on the reasons behind the management decision to construct the expansion. Omitted from the reasons PG&E provided for its decision to construct its expansion was its intention to gain the first mover advantage over the competing Altamont project, and the potential loss of a $44 million payment from TransCanada. As well, it appears [*70] that fewer shippers had contracts for Line 401 capacity than what PG&E represented to the Commission. The McLeod memo shows that in October 1991 PG&E held signed contracts for less than 25% of Line 401 capacity, n39 contradicting the earlier assertion that more than 80% of Line 401 capacity was subscribed by firm shippers. PG&E characterized the Edison and SDG&E commitments to Line 401 as being "fixed," but contracts were not yet signed. As discussed above, we no longer question the reasonableness of PG&E's decision to construct, even after review of the McLeod memo, but it appears that the disparities between PG&E's earlier testimony and the later-revealed McLeod memo may constitute a Rule 1 violation. Moreover, if PG&E's witness knowingly misled the Commission with PG&E's earlier testimony, this would constitute a felony under Section 2114 of the California Public Utilities Code.

n39 Exhibit 455, Attachment 1, Bates 000687.

Second, should the Commission impose penalties on PG&E for failure to provide the McLeod memo [*71] to other parties in response to explicit discovery requests? Edison, the Indicated Expansion Shippers, and New Mexico requested information of the type contained in the McLeod memo. In its Data Request No. 2, Q6, Edison requested "all documents that relate to PG&E's determination that there was sufficient demand to justify construction of the Project." n40 The McLeod memo certainly contains such information, and PG&E provided Edison with five paragraphs from the memo, claiming business confidentiality and attorney-client privilege for the rest of the document. PG&E did not provide or identify all documents as requested, but provided the excerpted paragraphs from internal documents "illustrating" factors considered by PG&E. In his first data request, consultant Thomas Beach, then a witness for the Indicated Expansion Shippers and more recently a witness for successor organization CAPP, sought identification of withheld documents and "a copy of all data requests obtained from any other party and all responses provided by PG&E to such data requests." n41 Beach later specifically asked for PG&E's answer to Edison's Second Data Request, Q6. n42 Neither CAPP nor the Indicated Expansion [*72] Shippers received a copy of the redacted McLeod memo that PG&E provided to Edison. New Mexico asked PG&E to provide all documents that discuss load factors for firm or as-available service on Line 401. n43 The McKinsey & Company study attached to the McLeod memo discusses demand forecasts, throughput levels, and utilization percentages, arguably the same measures of expansion project usage as load factor. New Mexico did not receive from PG&E either the McLeod memo or its identification as a confidential document.

n40 Edison March 10, 1995, response to motion to reopen, attached Exhibit "A", p. A-2.
n41 Norcen and TURN February 24, 1995, motion to reopen, attached Exhibit 3, Question A.6 and Question B.2.
n42 Norcen and TURN February 24, 1995, motion to reopen, attached Exhibit 5, Question 4.
n43 New Mexico March 10, 1995, response to motion to reopen, attached Exhibit "A", Question 16.

The evidence in dispute, and PG&E's failure to produce or identify the McLeod memo in discovery, causes us to be very concerned [*73] that PG&E may have violated our rules, including Rule 1 of the Commission's Rules of Practice and Procedure. Unfortunately, the parties to the **Gas Accord,** including ORA, erroneously believed that they could settle the alleged Rule 1 violations, and therefore, the termination of the Rule 1 allegation proceeding is a part of the **Gas Accord.**The sanctity of the Commission's rules is not a matter that private parties or the ORA can settle. Violations of our rules cannot be forgiven or traded for other concessions. Only the enforcement staff of the Commission (e.g., Consumer Services Division or other authorized enforcement staff) can negotiate a settlement with a utility involving Rule 1 violations, subject to an independent determination by the Commission as to whether or not to approve that settlement. The settlement of such violations should not be merged into a settlement of other unrelated issues.For this reason, when the Commission sees provisions settling Rule 1 violation allegations in a settlement involving private parties or the ORA, or any other provision parties have no lawful authority to settle, we will disregard the provision and consider it an ultra vires or unauthorized [*74] act. Under Rule 51.7 of the Commission's Rules of Practice and Procedure, we normally would allow parties a reasonable time to decide if Commission modifications to a settlement are acceptable. However, we do not consider striking an unauthorized or ultra vires provision to be a modification of a settlement, since the provision is a legal nullity. Therefore, if we consider the settlement to be otherwise in the public interest by striking unauthorized or ultra vires provisions, we do not view that as modifying the settlement under Rule 51.7 of our rules, and we instead consider the adoption of the settlement to be binding on the parties under Rule 51.8 of the Commission's Rules of Practice and Procedure. Accordingly, we will ignore the Rule 1 provision of the **Gas Accord.**After the alternate proposed decision of Assigned Commissioner Richard A. Bilas and Commissioner Josiah L. Neeper was mailed on June 11, 1997, PG&E met with representatives of the Commission's Consumer Services Division in order to negotiate a settlement and attempt to obviate the need for an Order to Show Cause proceeding concerning PG&E's alleged Rule 1 violations. On July 1, 1997, the Consumer Services Division [*75] submitted to the Commission a settlement between PG&E and the Consumer Services Division concerning the alleged Rule 1 violations (hereinafter the "Rule 1 Settlement"). The Rule 1 Settlement is attached to this order as Appendix E. n44

n44 Since private parties, other than the company allegedly committing the Rule 1 violations, have no right to participate in settlement concerning the alleged Rule 1 violations, there would be no reason to apply the comment periods normally provided under Rule 51.4 of our Rules of Practice and Procedure to the Rule 1 Settlement. Accordingly, pursuant to Rule 87 of our Rules of Practice and Procedure, we will sua sponte waive the 30-day comment period and 15-day reply period in Rule 51.4 in order to expeditiously rule on the Rule 1 Settlement.

The major provisions under the Rule 1 Settlement provide that, without admitting that it has committed a Rule 1 violation, PG&E would make a payment of $850,000 to the General Fund for the State of California, which would not be recorded as [*76] an operating expense by PG&E for ratemaking purposes. PG&E has further agreed in the Rule 1 Settlement that its professional-level employees, who routinely practice before the Commission, would take an ethics training course of at least four hours (and up to one full day) regarding the preparation and processing of discovery and prepared testimony.After reviewing the Rule 1 Settlement between PG&E and Consumer Services Division, we conclude, pursuant to Rule 51.1(e) of our Rules of Practice and Procedure, that the settlement is a reasonable resolution of the alleged Rule 1 violations in light of the whole record, that it is consistent with law, and that it is in the public interest. We therefore adopt the Rule 1 Settlement in its entirety.PG&E's agreement under the Rule 1 Settlement to pay $850,000 represents a substantial compromise by PG&E of alleged improprieties which, if proven, could lead to very serious consequences. Moreover, PG&E's agreement to have its employees, who routinely appear before the Commission, attend at least four hours of ethics classes, should help ensure that in the future PG&E's employees will not misrepresent matters or mislead the Commission whether [*77] or not PG&E employees have done so in the past.In view of PG&E's substantial compromises in the Rule 1 Settlement, we see no point to issuing an Order to Show Cause instead of approving the Rule 1 Settlement. Indeed, the Rule 1 Settlement avoids a protracted Order to Show Cause proceeding, and it is not clear that the proceeding would have resulted in fines equivalent to the amount of money PG&E has already agreed to pay. Moreover, PG&E's agreement to have employees attend an ethics training course should help prevent problems in the future.We want to emphasize to PG&E that we will not tolerate any violations of our rules. We will not allow utilities or any other parties to play fast and loose with our rules, and we expect PG&E management to take extra steps to ensure that its employees or agents strictly adhere to our rules and regulations when they represent PG&E in Commission proceedings.

6.3 Natural Gas Strategic Plan In comments to the ALJ's proposed decision, TURN argues that adoption of the **Gas Accord** will preclude revisions to PG&E's rates and services that might otherwise be ordered in the wake of the Commission's upcoming Natural Gas Strategic Plan (Plan). Several [*78] **Gas Accord** signatories disagree, claiming that the settlement will encourage progress toward future policy changes by resolving regulatory disputes over PG&E's past actions.PG&E asserts that the **Gas Accord** is consistent with the Plan and will not tie the Commission's hands in the future. PG&E states: n45

> "The Accord does not preclude the Commission's review of numerous other issues, such as core rate deaveraging or customer rate design, which are currently examined in Biennial Cost Allocation Proceedings. The Accord makes significant movement toward a more competitive procurement market, but does not limit additional steps, such as an examination of the role of utility core procurement as core aggregation increases. ...In addition, the Accord does not address changes in reliability standards, qualifications for electric generation rates in a post-divestiture environment, or the interactions of the electric industry and natural gas market unbundling at the distribution level. All of these important issues can be appropriately addressed in a state-wide strategic review."

n45 PG&E Reply Comments on the ALJ's Proposed Decision, filed April 30, 1997, p. 3.

[*79] PG&E is correct that approval of the **Gas Accord** does not preclude the Commission from moving forward on various other important natural gas issues. Our intention in the Plan is to review the structure of the industry and specific approaches to rate decisions, unbundling, market entry and related topics so as to promote a more competitive marketplace. While there are significant differences between the electric and natural gas industries, we intend to consider the electric industry model (and direct access for all customers classes in particular) for its applicability to the natural gas industry. It is possible that the natural gas strategic plan will lead to consideration of issues similar to or extended from issues addressed in the **Gas Accord.** It is our intention to fulfill the intent of the **Gas Accord** to provide stable and predictable backbone transmission rates throughout the **Gas Accord** period, as well as to see that its other provisions are fairly and properly implemented. However, if necessary, we will not hesitate to consider whether changes to **Gas Accord** issues should be made before the end point of the Accord in order to facilitate overarching policy goals. While we will respect [*80] the spirit of the settlement, it is not necessary to pledge that in the natural gas strategic plan the Commission will not consider changes to the **Gas Accord** given appropriate notice and due process.We will not delay approval of the **Gas Accord** in order to consider the Plan, but we intend to hold PG&E to its word that our approval of the **Gas Accord** will not limit the Commission's authority if the Plan requires changes to PG&E's ratemaking structure or to PG&E's services. Even without PG&E's recognition of possible changes, we may revisit **Gas Accord** issues pursuant to PU Code § 1708.

6.3.1 Rolled-In Rates 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 [*81] 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.**

6.3.2 Core ProcurementTURN raises an important issue about PG&E's core procurement practices. TURN fears that penalties accruing under the adopted CPIM may not be sufficient to deter PG&E from taking actions that benefit shareholders to the detriment of core customers. TURN then suggests that an independent procurement officer (IPO) can mitigate this problem. PG&E responds: [*82] n46

> "Employing a performance-based ratemaking mechanism does not remove a utility's procurement practices from the scrutiny of the Commission. The Post-1997 CPIM assumes a quarterly and annual reporting requirement. If Southwest gas became the least-cost supply option and PG&E continued to procure more-expensive Canadian supplies for the core, such behavior would certainly come to the Commission's attention. PG&E assumes that penalties for behavior favoring shareholder interests at the expense of core interests would not be limited to those accrued under the CPIM."* * *
>
> "If the Commission believes that an independent procurement mechanism may be an appropriate alternative, the Commission could initiate a proceeding to evaluate the concept and set a procedural schedule for such examination after a decision on the **Gas Accord** is issued."
>
> n46 PG&E Supplemental Report Describing the Post 1997 Core Procurement Incentive Mechanism (CPIM), dated October 18, 1996, pp. 1-8 and 1-9.

We agree with PG&E that the CPIM will [*83] not be the sole device by which the Commission will protect PG&E's ratepayers to the extent that PG&E puts its shareholder interests ahead of ratepayer interests and PG&E unreasonably purchases gas at prices higher than available alternatives. We can consider this matter in affiliate abuse proceedings and other proceedings, and disallowances or penalties for PG&E's behavior favoring shareholder interests over ratepayer interests are not just limited to scenarios in which Southwest gas is the lowest cost core supply. We intend to look carefully at any situation where utility costs of core procurement are unreasonably high due to PG&E's conflicts of interests. Possibilities include CPIM operations, interstate gas swaps with affiliated pipeline operations, and affiliate abuses in general. In order to stay informed about PG&E's core procurement practices, we will require PG&E to file core procurement reports quarterly and annually as provided in the **Gas Accord.**While we do not place total reliance on PG&E's CPIM for protecting PG&E's ratepayers, we nevertheless believe that the CPIM is in the public interest for increasing PG&E's incentive to minimize its procurement costs for its core [*84] customers. Therefore, subject to our continued oversight to address any procurement abuses, we will approve the revised 1994-97 CPIM, as well as the post-1997 CPIM. Moreover, the Commission may still initiate a proceeding to consider requiring an IPO, so we reserve the right to do so notwithstanding our approval of the CPIM.

6.4 Discounting We will not find that the **Gas Accord** is reasonable or in the public interest without mitigation of PG&E's future conflict of interest under the settlement wherein PG&E will continue to favor its Malin to on-system path (Line 400/401) over its Topock to on-system path (Line 300) or its California production to on-system path (California Gas Production Path). We cannot allow PG&E to maximize transportation rates on Line 300 or its California Gas Production Path by refusing to discount the tariff rate, then discounting rolled-in Line 400/401 service to compete with these other rates at the burnertip.On June 11, 1997, Assigned Commissioner Richard A. Bilas and Commissioner Josiah L. Neeper mailed an alternate proposed decision to all parties, which indicated that the Commission intended to issue an Order Instituting Rulemaking (OIR) to address [*85] a proposed discounting rule. In the comments filed on the alternate proposed decision, numerous parties urged the Commission to address the discounting rule in the order on the **Gas Accord** rather than in a separate OIR proceeding. Therefore, on June 24, 1997, Commissioner Richard A. Bilas issued an Assigned Commissioner's Ruling Regarding Alternate Decision asking parties to comment on two issues. The first issue was a proposed rule that "PG&E shall offer a commensurate discount on Line 300 whenever offering any discount for Line 400/401 or Line 401 Service. This rule does not apply to off-system sales." The parties to the **Gas Accord** were specifically requested to indicate if they all could accept this rule, in which case it could be accepted into the Alternate

Order. The second issue was whether to adopt TURN's proposal of crediting $94.1 million to the Core Fixed Cost Account (CFCA). Comments were due by July 1, 1997, and nine comments were filed on that date.In comments responsive to the Assigned Commissioner's Ruling, almost all of the signatories to the **Gas Accord** stated (or authorized others to state) that they supported or did not oppose a discounting rule (with certain clarifications) [*86] as an amendment to the **Gas Accord.** n47 However, in its July 1, 1997 comments, the City of Palo Alto, a signatory to the **Gas Accord,** objected to having the discounting rule become part of the **Gas Accord.** Therefore, on July 2, 1997, Assigned Commissioner Richard A. Bilas and Commissioner Josiah L. Neeper mailed a revised, alternate proposed decision to all parties, which noted the City of Palo Alto's opposition to the discounting rule and again indicated that the Commission intended to address this matter in a separate OIR. The July 2, 1997 revised, alternate proposed decision clarified that the proposed discounting rule would require PG&E to offer to all shippers a commensurate discount (i.e., penny for penny) on Line 300 and its California Gas Production Path whenever offering any discount to any shipper for similar Line 400/401 services (e.g., as–available services).

> n47 In sharp contrast to the discounting rule, most of the signatories to the **Gas Accord** indicated that adoption of TURN's CFCA proposal would substantially modify and upset the balance in the **Gas Accord.** In addition, supporters of the **Gas Accord** challenged the support in the record for the TURN CFCA proposal, and indicated problems of attempting to address the TURN CFCA proposal in a rulemaking proceeding. After reviewing all of these comments, we have decided not to adopt TURN's CFCA proposal.

[*87] The July 2, 1997 mailing of the revised, alternate proposed decision resulted in another round of initial and reply comments. In their initial comments, the signatories to the **Gas Accord** (except the City of Palo Alto) represented that they supported or did not oppose amending the **Gas Accord** to include the discounting rule as clarified in the July 2, 1997 revised, alternate proposed decision. In its July 14, 1997 reply comments, the City of Palo Alto stated that after further consideration of this issue, it no longer objects to inclusion of the discounting rule as part of the **Gas Accord.**In view of the above, all of the signatories to the **Gas Accord** have now elected to accept the discounting rule as an amendment to the **Gas Accord,** and, therefore, under Rule 51.7 of our Rules of Practice and Procedure, the Commission may approve the **Gas Accord,** as amended by the discounting rule, without addressing this matter in a separate OIR proceeding. Moreover, even opponents of the **Gas Accord** (such as TURN and New Mexico) have stressed the need to implement a remedy to PG&E's conflicts of interest at the time that the **Gas Accord** is implemented.In view of all of these comments, we therefore find [*88] good cause for amending the **Gas Accord** and imposing the following discounting rule on PG&E when it implements the **Gas Accord.** Whenever PG&E offers any shipper (e.g., a marketer, aggregator, or end–user) a discount on its Malin to on–system path (Line 400/401), PG&E is required to contemporaneously offer a commensurate discount (i.e., penny for penny) to all shippers for similar services on its Topock to on–system path (Line 300) and its California Gas Production Path. (Hereinafter, this will be referred will be as the "commensurate discount rule"). By similar services, we mean that PG&E's offer of discounts for as–available (or interruptible) service on Line 400/401 must be matched by PG&E's offer of commensurate discounts for as–available (or interruptible) service on Line 300 and its California Gas Production Path. Similarly, if PG&E offers discounts for firm service on Line 400/401, it must offer the same discount for firm service on Line 300 and its California Gas Production Path. PG&E's offer of such discounts must take place contemporaneously, which means that PG&E may not offer or make known its intent to offer Line 400/401 discounts earlier in time than offers of discounts [*89] on Line 300 and its California Gas Production Path.Because our finding of PG&E's conflict of interest centers on PG&E's marketing of its on–system paths, we are not at this time imposing this discounting requirement when PG&E offers discounts for its Malin to off–system (Line 401) rates. n48 It is because we have made an explicit finding that PG&E has a conflict of interest favoring its Line 400/401 service over its Line 300 service that we need to address this problem with this commensurate discount rule. However, we have not found that PG&E has a conflict of interest favoring its Line 300 service over its Line 400/401 service. Therefore, we reject without prejudice CAPP's suggestion that there should be a reciprocal condition requiring discounts of Line 400/401 rates whenever PG&E discounts Line 300 rates. However, if CAPP or any other party were to establish that PG&E has a conflict of interest favoring its Line 300 service over its Line 400/401 service, we would consider CAPP's proposed discounting requirement at that time.

> n48 We reserve, however, the right to further consider imposing such a requirement to the extent that this Line 401 exception to the discounting rule allows PG&E or marketers to circumvent the discounting rule or it is shown that PG&E's conflict of interest affects discounts on its Line 401 rates or service.

[*90] We believe that this discounting rule will help mitigate PG&E's conflict of interest favoring the marketing of its Line

400/401 service over its Line 300 service. If PG&E discounts the Line 300 rate and California Gas Production Path rate when it discounts Canadian path rates, then Southwest gas and in–state production will not have to overcome the hurdle of a maximum tariff rate while Canadian gas reaches California using discounted transportation service. Discounted Line 400/401 rates might still be higher than the tariffed Line 300 rate and the California Gas Production Path rate, but the Canadian supply price advantage would allow Canadian producers gas to undercut Southwest and California gas prices at the burnertip. It would be unfair and unduly discriminatory to allow PG&E to prop up the market clearing price by refusing to discount Line 300 rates or California Gas Production Path rates while discounting its Line 400/401 rates. A fair discounting rule would be consistent with discounting practices authorized earlier in this proceeding in D.94–02–042. n49

n49 53 CPUC2d 215, 239–240 (1994).

[*91] We conclude that imposing a discounting rule is not inconsistent with adoption of the **Gas Accord** and does not disturb its provisions. Discounting is mentioned in several places in the **Gas Accord** document, n50 but we find no explicit provision that gives PG&E unbridled discretion over discounting among competing services when PG&E's Line 400/401 rates are higher than its Line 300 rates, and PG&E is prohibited from providing unduly discriminatory discounts. Moreover, all signatories to the **Gas Accord** have now elected to accept this discounting rule as an amendment to the **Gas Accord.**

n50 Appendix B, pp. 7, 8, 31, 34, 47, 48.

Both TURN and New Mexico have pointed out that PG&E could shift discounts on Line 400/401 upstream to discounts on PG&E's subsidiary, PGT, in order to circumvent this rule and to never offer discounts on Line 300 or its California Gas Production Path. As New Mexico further points out in its July 1, 1997 comments on the Assigned Commissioner Ruling and as we have found in this order, we cannot anticipate [*92] all future PG&E and market responses to PG&E's conflict of interest. Just as we did not predict backbone credit exchange agreements or the expansion shippers' numerous transactions to circumvent our crossover ban, we cannot predict how PG&E and/or marketers may attempt to circumvent the commensurate discount rule we have just adopted.While we will not institute a rulemaking at this time and have instead imposed a discounting rule as part of this order, we agree with New Mexico that we have to continue to scrutinize PG&E's conduct and any further problems that may result from PG&E's conflicts of interest. Therefore, we are requiring PG&E to publicly file with our Energy Division on or before March 1, 1999 and serve all parties on the **Gas Accord** service list in A.92–12–043, et al. a market assessment report that covers pipeline system operations from the implementation date of the **Gas Accord** through the end of 1998. In addition to the type of information which PG&E provided in the market assessment report it previously filed herein, PG&E shall include in its market assessment report a detailed and meaningful report of each and every discount transaction (e.g., indicating level [*93] of discount, shippers, length of discount, dates of discounts, type of service) which PG&E offered and/or entered into (from the implementation date of the **Gas Accord** through December 31, 1998) for Line 401 rates, Line 400/401 rates, Line 300 rates and California Gas Production Path rates and which PGT, PG&E's subsidiary, offered or entered into for its rates to California and/or to the Malin delivery point.The public disclosure of these discounts is necessary so that parties can address and we can determine whether our commensurate discount rule has been circumvented or whether our requirement is insufficient to remedy problems caused by PG&E's conflict of interest. However, we have required after the fact reporting in order to mitigate any competitive harm which could otherwise occur to PG&E from such a public disclosure.To the extent that we were to subsequently determine after reviewing this report that the commensurate discount rule is insufficient to redress PG&E's conflict of interest and anticompetitive behavior, we could consider and impose further measures, such as broadening PG&E's commensurate discount requirement to match Line 401 rate discounts (and/or PGT's Malin [*94] delivery rate discounts) or requiring PG&E to divest Line 300 and/or its California Gas Production Path. Therefore, it could prove counterproductive for PG&E and/or others to attempt to game our commensurate discount rule and render it meaningless. Having found that PG&E has a conflict of interest and recognizing how PG&E could undermine fair competition from non–Canadian suppliers, we intend to scrutinize PG&E's discounts and take appropriate actions in the future, if necessary, in order to provide an effective remedy. We are hopeful, however, that PG&E and others will take this warning seriously and comply with both the letter and the spirit of our commensurate discount rule so that further actions on our part in this regard are not necessary.

6.5 Side Deal Payment The side deal between Edison and PG&E, formally identified as an amendment to Edison's contract for firm Line 401 transportation service, includes a "transaction price," which is a one–time payment from

Edison to PG&E. The transaction price was submitted to the Commission pursuant to the confidentiality protections of PU Code § 583, but those protections expired on May 16, 1997. The negotiated transaction price [*95] is $80 million. The ratemaking treatment of this amount by Edison and PG&E is uncertain. Should the $80 million be used to decrease PG&E's capital costs or revenue requirements? Should the $80 million be credited to its ratepayers?We will not order any specific ratemaking treatment in this decision, but we will require PG&E to clarify its intentions by advice letter concerning Edison's payment and any other side deal payment. Any interested party may respond to PG&E's proposed ratemaking treatment, and we will thereafter decide this matter in a Commission resolution.

6.6 Distribution Discount Shortfalls Under the **Gas Accord,** it is unclear whether PG&E or ratepayers will be responsible ultimately for revenue shortfalls caused by distribution discounts. PG&E's motion for adoption states, "After implementation of the **Gas Accord,** PG&E will no longer collect any revenue shortfalls from ratepayers and will assume 100 percent shareholder responsibility. Under the **Gas Accord,** PG&E will be permitted to discount transmission and distribution rates on a nondiscriminatory basis but will be at risk for any resulting revenue shortfalls." n51 Although this text appears in a section [*96] on EAD discounts, the text provides no basis from limiting its discussion to only EAD revenue shortfalls from discounts.

n51 PG&E motion filed August 21, 1996, pp. 15-16.

The **Gas Accord** itself states, "PG&E will have the option in BCAP proceedings of demonstrating the reasonableness of any discounted distribution contracts that will continue into the prospective period. If the Commission finds the discounts to be reasonable, PG&E will be allowed to recover the forecasted revenue shortfalls during the prospective period." n52

n52 Appendix B, Paragraph III.C.8.f, p. 48.

We will resolve this ambiguity against PG&E. There is no ambiguity that PG&E shareholders will bear 100% of the responsibility for revenue shortfalls from transmission rate discounts. For PG&E to be "at risk" for any resulting revenue shortfalls from distribution rate discounts, it must [*97] mean, at the very minimum, that there is a strong presumption that PG&E shareholders should bear 100% of the responsibility for revenue shortfalls resulting from discounts in distribution rates. Therefore, while PG&E has an option to seek in BCAP proceedings forecasted revenue shortfalls from distribution discounts, PG&E has a very heavy burden to first demonstrate that the discount is reasonable. In addition, in light of PG&E's conflict of interest favoring its Line 400/401 transportation, we cannot foresee any situation whereby we would find distribution rate discounts reasonable in conjunction with Line 400/401 service.

7. Joint Recommendation The full Joint Recommendation is 22 pages long and is attached to the September 24, 1996, motion for adoption filed by its sponsoring parties: DGS, New Mexico, and TURN. The Joint Recommendation is summarized in Appendix D to this decision, taken from a workshop document.Briefly, the Joint Recommendation would: (1) retain Line 300 and Line 400 as assets in PG&E's rate base; (2) treat Line 401 as a separate, unbundled facility with its own rate base and revenue requirement; (3) reserve specific capacity amounts for core customers; (4) [*98] establish an IPO to manage core and UEG procurement; (5) offer noncore access to Line 400 and Line 401 at monthly posted prices; (6) offer access to Line 300 by auction; (7) credit noncore capacity brokering revenues back to noncom customers; and (8) allocate constrained receipt point capacity by price. The current crossover ban and RPCA rules would end. The new market structure would become effective January 1, 1998. The Joint Recommendation would not resolve litigation of Rule 1 allegations, Line 401 capital costs, ITCS amortization, or CPIM proposals.According to its backers, the Joint Recommendation offers a competing vision of future gas markets in California, and would neutralize but not cure the conflict of interest inherent in the **Gas Accord.** It would promote competition, retain for PG&E ratepayers the economic value of original system facilities, retain incremental ratemaking for Line 401, and eliminate balancing account treatment for original system facilities assigned to the noncore. Today's Northern California gas prices are determined by Southwest gas prices; Line 300 prices under the Joint Recommendation would be lower than Line 300 prices under the **Gas Accord.** Although [*99] the existing record supports the concepts in the Joint Recommendation, further implementation proceedings would be required.Parties to the **Gas Accord** generally oppose the Joint Recommendation. CIG and CMA together and PG&E point out that the majority of noncore end users support the **Gas Accord,** not the Joint Recommendation. Various parties argue that the Joint Recommendation would be a step away from unbundling, flexible service options, and secondary capacity markets. The Commission has supported these market features in past decisions. Other failings, according to **Gas Accord** parties, are lack of detail, rate uncertainty during upcoming years, the risk that burnertip gas prices will rise, discrimination problems under posted pricing for Line 400 and Line 401, possible confiscation of utility property inherent in capacity brokering guarantees, and the need to litigate current Commission proceedings. Amoco opposes capacity allocation by price. CCC fears the Joint Recommendation will cause problems with cogenerator parity as required by PU Code § 454.4. Enserch believes the worst feature of the Joint Recommendation is imposition of an untested market structure. Several parties characterize [*100] the Joint Recommendation as a subsidy scheme for Southwest producers and pipeline companies.Apache and CAPP, which did not sign the **Gas Accord,** argue that fully rolled–in, postage stamp gas transmission rates would resolve many market problems. Norcen, which also opposes incremental rates for Line 401, would extend the proposed IPO to operation of all PG&E transmission facilities, unless PG&E divests those assets.The sponsors admit that the Joint Recommendation is more narrow in scope than the **Gas Accord,** and there are fewer supporters of the Joint Recommendation than of the **Gas Accord,** in part because unlike PG&E the sponsors cannot offer financial inducements to prospective partners. The sponsors claim that PG&E's conclusion that the Joint Recommendation will result in higher gas prices than the **Gas Accord** is misleading and implausible. They believe Line 300 auction prices would exceed **Gas Accord** rates only in extreme and temporary conditions. Finally, they assert that rate uncertainty should be expected in deregulated markets, and is minor relative to uncertainty in gas supply prices.The Joint Recommendation has several appealing features. Its principal virtue is that it would [*101] allow market forces, not PG&E, to control Line 300 prices, thereby removing much of the potential for ratepayer harm associated with PG&E's conflict of interest. The Line 300 auction proposal would keep the net costs of Southwest gas low, except in periods of very high demand. This would effectively prevent the transfer of roughly $0.15/Dth in economic value from California end users to northern interests under the **Gas Accord.** Second, the Joint Recommendation would retain incremental ratemaking for Line 401, avoiding subsidies by original system ratepayers and the undermining of public confidence in future market tests for new capacity. Allocation of receipt point capacity by price would be a fair way to let market participants compensate the holders of valuable pipeline space. The IPO proposal is an intriguing idea. It would further reduce PG&E's conflict between shareholder and ratepayer interests, but we are not entirely comfortable with adopting it based on the current record.We appreciate customer desires for rate certainty, but we will not criticize the Joint Recommendation for variability in market prices. As the sponsors suggest, price uncertainty often accompanies deregulation [*102] of rates. Rate certainty becomes a service attribute with market value, and customers can buy the certainty they need. In response to arguments that the Joint Recommendation market structure is untested, it seems to share that quality with the **Gas Accord** market structure, more or less in equal measure. Nor will we condemn the Joint Recommendation for its reduced scope compared to the **Gas Accord.** The record on many contested issues—the decision to construct, ITCS amortization, and conditions of service on Line 401, for example—is complete, and PEPR testimony has been served.On the other hand, the Joint Recommendation contains two serious flaws. We agree with PG&E and its allies that the Joint Recommendation would be contrary to our preference for unbundled utility service. It would be a step backward in what we believe is a natural progression toward customer choice among flexible service options. We are also troubled by the inconsistency between auction pricing of Line 300 capacity and posted pricing for Line 400 capacity. Without expressing a preference for either approach, we are concerned that the disparity in methods could introduce unanticipated and harmful market manipulation. [*103] It is not necessary to study PG&E's arguments regarding confiscation of utility property. We can make the necessary findings regarding the Joint Recommendation without resolving that issue.Based on the record before us, we cannot find that the Joint Recommendation is reasonable. The move away from unbundling is unacceptable and cannot be balanced against the advantages of the Joint Recommendation. The inconsistency of pricing schemes can be offset to some degree by the benefits of the Joint Recommendation, but we will not adopt it as a package.

8. ITCS and Backbone Credit Amortization The **Gas Accord** was reached after development of a full record on ITCS and backbone credit amortization issues. We should review that record in order to test the reasonableness of the settlement.In A.94–06–044, PG&E asked to amortize in rates $60.1 million of recorded and forecast costs in its ITCS account, for the period from August 1, 1993, through December 31, 1994. Amortization would have begun September 1, 1994, and the account would continue to record ITCS costs until the expiration of PG&E's contract with PGT in 2006. PG&E originally sought ex parte approval of a noncore amortization rate [*104] of $0.14/Dth, and no core rate. Four parties—CIG and CMA together, DRA, El Paso, and Palo Alto—protested the application. CIG/CMA and El Paso argued that PG&E's marketing efforts in support of Line 401 have increased ITCS charges. Palo Alto sought a reduced ITCS rate because it serves core customers. In D.94–11–024, the Commission authorized a noncore ITCS rate of $0.07/Dth, subject to refund. On February 9, 1995, ALJ Robert Barnett issued a ruling which identified disputed issues and ordered hearings to evaluate the legitimacy of costs in the ITCS account. In D.95–04–007, the Commission approved an agreement between PG&E and Palo Alto that reduces the ITCS rate for Palo Alto and the City of Coalinga. On January 29, 1996, before the scheduled hearings began, the ITCS application was consolidated with this proceeding. In Resolution G–3142, approved

August 2, 1996, the Commission authorized a $0.06/Dth reduction of the noncore ITCS rate, with PG&E shareholders at risk for associated revenue shortfalls. The resolution preceded PG&E's filing of the **Gas Accord,** but the rate reduction is an element of a **Gas Accord** side deal between PG&E and CIG/CMA.The Commission has always intended [*105] that ITCS amortization by PG&E should be subject to reasonableness review. In D.91-11-025, the Commission rejected a settlement that proposed the ITCS mechanism, but adopted capacity brokering rules based on the settlement. n53 The settlement called for amortization after Commission findings that costs were reasonably incurred. In D.94-11-024, the interim ITCS rate was made subject to refund "should the stranded ITCS costs prove to have been caused by improper acts of PG&E." n54

n53 D.91-11-025, 41 CPUC2d 668, discussion at 696, Ordering Paragraph 3 at 707, Rule F at 728 (1991).
n54 D.94-11-024, Ordering Paragraph 3, 57 CPUC2d 309, 313 (1994).

In seeking to justify costs in the ITCS account, PG&E begins by arguing that ITCS obligations, which are principally El Paso demand charges for unused pipeline capacity, are sunk costs in economic terms. Therefore, they do not harm ratepayers. PG&E submits that it should be allowed full ITCS recovery because it has followed all applicable rules and guidelines in its capacity [*106] marketing activities. By setting Line 401 prices which compete with brokered interstate capacity, PG&E claims that it is taking a competitive stance in the marketplace, and that competition in general has brought billions of dollars in benefits to California consumers. The Commission has recognized that new pipeline capacity is essential to fostering gas-on-gas and pipeline-on-pipeline competition. PG&E opposes the theories of TURN and El Paso that Line 401 marketing activities have devalued brokered El Paso capacity. PG&E believes that its actions should be judged against what a reasonable manager of sufficient education, training, experience, and skills would do in similar circumstances. n55 According to PG&E, its capacity brokering actions meet that standard because PG&E: (1) promoted the brokering of excess capacity in competitive markets, (2) created separate marketing teams for Line 401 and brokered capacity, (3) avoided unnecessary discounting, (4) used minimum bids responsibly, (5) negotiated prices below minimum bids in order to meet market prices, and (6) sought to maximize capacity brokering revenues. In marketing competing Line 401 capacity, PG&E claims that it has again [*107] followed Commission rules and guidelines, and has not driven Southwest competitors from the market.

n55 D.90-09-088, 37 CPUC2d 488, 499 (1990).

In its prepared testimony, DRA recommended no disallowance of ITCS costs, but asked that the ITCS account be terminated when PG&E's contracts with El Paso expire at the end of 1997. In briefs, DRA revised its position, alleging that PG&E's conflict of interest has increased shareholder earnings at ratepayer expense. Therefore, DRA recommended disallowance of 50% of past ITCS costs and elimination of core responsibility for future costs. DRA later signed the **Gas Accord,** under which PG&E would bear all core ITCS costs and 50% of noncore ITCS costs.TURN argues that core customers should be made indifferent to operation of Line 401 by adjustment of $40.1 million in 1993 and 1994 costs, separated into $13.2 million of ITCS costs and $26.9 million of unrealized capacity brokering revenues that should have been credited to PG&E's core fixed cost account. These amounts, which include [*108] core portions of Transwestern pipeline costs, should be disallowed or reassigned to the noncore. The core indifference policy should also be applied prospectively. TURN believes that ITCS costs and lost revenues are the direct result of PG&E's Line 401 marketing practices, which are driven by PG&E's conflict between shareholder and ratepayer interests.El Paso asserts that ITCS and core capacity costs associated with Line 401 pricing practices should be allocated to the Line 401 revenue requirement. According to El Paso, PG&E's Line 401 practices, core and UEG procurement practices, and use of Transwestern capacity have caused stranded costs of approximately $101 million through May 1995. PG&E's conflicts of interest have led PG&E to favor Canadian over Southwest supplies.New Mexico also believes that PG&E's actions have hindered the operation of a competitive market for gas in Northern California. According to New Mexico, PG&E's minimum bids, service terms, and marketing efforts have consistently favored Line 401 over brokered Southwest capacity. New Mexico supports El Paso's determination of stranded costs, and recommends that PG&E shareholders be held responsible for all ITCS [*109] costs.We reject PG&E's arguments that capacity brokering has no effect on ratepayers. As discussed earlier in this decision, ITCS costs are fixed, but loss of capacity brokering revenues has affected the set of all PG&E customers except the shippers that choose Line 401 capacity over brokered Southwest capacity. Such lost revenues are direct harm to captive original system ratepayers caused by PG&E's marketing practices.We accept use of the "reasonable manager" standard in the present circumstance, but other prudence standards apply as well: (1) the utility has the burden to show with clear and convincing evidence that its operations have been reasonable and prudent; (2) the Commission has a legitimate concern with the processes employed to reach management decisions, not only with outcomes; (3) reasonableness depends on the information that managers knew or should have known; (4) utility actions should reflect the exercise of good judgment and should be expected to reach the desired result at the lowest reasonable cost consistent with good utility practices; (5) reasonable and prudent acts do not require perfect foresight or optimum outcomes, but may fall within a spectrum of possible [*110] acts consistent with utility needs, ratepayer interests, and regulatory requirements; and (6) Commission guidelines are only advisory in nature, and do not relieve the utility of its burden to show that its actions were reasonable in light of existing circumstances. Many past Commission decisions support these principles.We find that by exercising market power in setting Line 401 prices that compete against brokered Southwest capacity, PG&E has imprudently placed shareholder interests above original system ratepayer interests. PG&E has failed the "best efforts" standard ordered by the Commission for marketing of unused interstate capacity. n56 The individual PG&E managers in charge of Line 401 sales and capacity brokering sales may have acted reasonably, but PG&E senior managers in control of both activities have relied on market power to the detriment of ratepayers, have failed to recognize the importance of PG&E's conflict of interest, and have failed to resolve the conflict of interest in a reasonable manner, either by establishing a fair balance of shareholder and ratepayer priorities or by promptly bringing the conflict of interest to the Commission's attention.

n56 D.91-11-025, Appendix B, Rules for Natural Gas Transportation and Capacity Brokering, Rule III.G.3, 41 CPUC2d 668, 724 (1991).

[*111] When it sold Line 401 capacity, PG&E held sufficient market power to undercut Southwest prices and drive capacity brokering sales down to nearly zero. Instead, PG&E priced Line 401 to meet Southwest prices, and noncore marketers took approximately equal fractions of the available competing supplies. This rough balance shows that PG&E had market power, not that PG&E was merely a player in a competitive market. Line 401 prices met Southwest prices, not the opposite. PG&E's attention to shareholder interests is further revealed by its focus on Line 401 marketing promotions and by continued reliance on minimum bids for brokered capacity. The evidence does not rigorously prove any dependence of brokered capacity prices on minimum bids, but minimum bids otherwise serve very little purpose.We make no attempt to weigh customer harm caused by PG&E's conflict of interest against overall competitive benefits caused by the pipeline expansion. We appreciate that increased interstate pipeline capacity and access to Canadian supplies have brought down California gas prices, but we cannot attribute specific benefits to Line 401. Those benefits could have been achieved without PG&E's ongoing conflict [*112] of interest.After review of all the facts and arguments before us, we judge that the **Gas Accord** fairly resolves ITCS issues. PG&E will absorb 50% of noncore ITCS costs, less brokering credits, and 100% of core ITCS costs, less credits. These amounts are higher than the relief recommended in the ALJ's proposed decision. The record does not show whether interim rate revenues to date have recovered noncore ITCS obligations.Turning to the backbone credit balancing account, we see a similar situation. PG&E sought rate recovery of the full amount in the account, arguing that its backbone credit transactions followed Commission rules and were reasonable. Prior to the **Gas Accord,** DRA and TURN recommended that PG&E be denied recovery of any backbone credit costs. They also recommended termination of new entries to the account, which we have accomplished in D.96-09-095. El Paso opposes PG&E recovery of backbone credits awarded to its UEG department, and supports rehearing of Resolution G-3122, in order to reduce the applicability of backbone credits. El Paso opposes PG&E recovery of backbone credits previously awarded to ineligible customers.In D.96-09-095, we found that backbone credit [*113] benefits flowed to PG&E shareholders and holders of upstream pipeline capacity rather than end users, that the backbone credit partially subsidized Line 401, and that Southern California exchange agreements were contrary to the purpose of the credit. n57 We now find that in its pursuit of shareholder benefits through backbone credit transactions, PG&E again imprudently placed shareholder interests above original system ratepayer interests. PG&E senior managers exercised market power to the detriment of ratepayers, failed to recognize the importance of PG&E's conflict of interest, and failed to resolve the conflict of interest in a reasonable manner.

n57 D.96-09-095, Findings of Fact 6, 8, and 11, at mimeo. pp. 12-13 (1996).

PG&E shareholder responsibility for 100% of backbone credit costs under the **Gas Accord** is a reasonable resolution of this dispute. As was true for ITCS costs, the settled amount exceeds the relief recommended in the ALJ's proposed decision. It is reasonable that foregone backbone credit amortization [*114] exceed foregone ITCS amortization because PG&E actively pursued shareholder revenues, as opposed to meeting Southwest prices when selling Line 401 capacity.

9. Rate Case Issues In this chapter of the proposed decision, the ALJ addressed Line 401 general rate case disputes for which a record was developed before the settling parties signed the **Gas Accord.** Our approval of the **Gas Accord** obviates further consideration of these conventional rate case issues: market-based rates for as-available service; recourse rates;

straight fixed variable rate options; load factor used in rate calculations; posted discount offers; revenue shortfalls caused by discounting; social and transition costs for direct connection customers; interim RPCA procedures; filing of contracts; backhaul service; and minimum bids.

10. ProceduresPG&E's motion for adoption of the **Gas Accord** anticipates informal workshops on tariff issues, submission of a compliance or implementation advice filing 45 days after Commission approval of the settlement, approval of the advice filing by Commission resolution, and a subsequent open season for gas transmission and distribution services. n58 We assume that informal [*115] tariff workshops have been completed or are underway. We accept PG&E's request for 45 days to prepare a tariff filing.

n58 PG&E motion filed August 21, 1996, p. 48.

We leave the Line 401 general rate case open: (1) to consider A.94-05-035 and A.94-06-034, which are outstanding applications for rehearing of Resolution G-3122; and (2) to provide access to the record during the **Gas Accord** implementation process.

11. Proposed Decision In compliance with PU Code § 311(d), the ALJ prepared a proposed decision in this matter. The proposed decision was mailed to all parties on March 24, 1997. Twenty-three parties filed comments, and fifteen parties filed replies to comments. The Docket Office properly rejected reply comments by the Association of Bay Area Governments because that entity is not a party to the proceeding. Pursuant to Rule 77.6(c), Assigned Commissioner Richard A. Bilas and Commissioner Josiah L. Neeper mailed an alternate proposed decision to all parties on June 11, 1997. Fifteen parties filed comments, [*116] and five parties filed replies.After considering these comments, on June 24, 1997, Assigned Commissioner Richard A. Bilas issued a ruling regarding alternate decision which requested further comments by July 1, 1997. On July 1, 1997 eleven parties filed comments in response to the Assigned Commissioner's Ruling Regarding Alternate Decision. In addition, on July 1, 1997, the Commission's Consumer Services Division submitted its settlement with PG&E to resolve the alleged Rule 1 violations.All of the above-mentioned comments and the Rule 1 Settlement were considered and resulted in Assigned Commissioner Richard A. Bilas and Commissioner Josiah L. Neeper mailing a revised alternate proposed decision to all parties on July 2, 1997. Seven parties thereafter filed comments, and three parties filed replies. We have considered all of these comments in rendering this decision.The revised alternate proposed decision forms the basis for this order. In the process of approving the **Gas Accord** we have reviewed and carefully considered the comments of the parties. We retain findings from the ALJ's proposed decision regarding market power and conflict of interest, but we have reversed his recommendation [*117] to deny approval of the settlement.Several members of NCPA, which is a **Gas Accord** signatory, comment that neither the **Gas Accord** nor the proposed decision allow municipal electric power producers access to the same gas transportation charges as PG&E's UEG department. If adopted, this parity would give municipal utilities the same rate treatment as cogenerators. NCPA asks the Commission to rectify the omission. In a related matter, SoCalGas comments that the **Gas Accord** does not address transportation service priority for third party gas storage providers compared to priority for PG&E's own storage service. SoCalGas asks the Commission to make it clear that utility and non-utility storage have the same priority. We decline to adopt the recommendations of NCPA and SoCalGas. These rate parity issues are beyond the scope of the record in the Line 401 general rate case.

Findings of Fact1. Line 401 competes directly with Southwest interstate pipelines.2. PG&E sets prices for Line 401 as-available service based on competitive alternatives at Topock.3. The dominant firm/competitive fringe model is a reasonable description of market dynamics at Topock.4. Market concentration, ease [*118] of substitution for pipeline capacity, similarity of pipeline cost functions, barriers to market entry, and inelastic demand for capacity give SoCalGas and PG&E incentives to exercise price leadership at Topock.5. Increasing gas market integration is not sufficient to prevent PG&E from exercising market power.6. Supply basin competition and burnertip price competition do not preclude the exercise of market power in the transportation corridor between Canada and California.7. PG&E holds market power at Topock and within California.8. In the context of this proceeding, a conflict of interest arises when PG&E has a duty on behalf of shareholders to contend for outcomes which its duty to ratepayers requires PG&E to oppose.9. A conflict of interest exists whenever there is a reasonable possibility that PG&E will not exercise its discretion fairly.10. PG&E has a conflict of interest in marketing Line 401 capacity on behalf of shareholders and brokering unused Southwest capacity on behalf of ratepayers.11. Under the **Gas Accord,** PG&E would have a conflict of interest in marketing its Line 400/401 capacity, as opposed to its Line 300 capacity or California Gas Production Path capacity, [*119] since

PG&E could collect greater revenues from increased throughput over Line 400/401, and its subsidiary, PGT, could collect greater revenues from increased throughput in lieu of throughput on the Southwestern interstate pipelines.12. The **Gas Accord** is reproduced in Appendix B to this decision.13. The **Gas Accord** has several features that support its approval: (1) it has the support of a broad spectrum of active parties; (2) it would unbundle PG&E's gas transmission system into separate services, and make PG&E responsible for system revenue requirements; (3) it would resolve difficult issues in several Commission proceedings and a federal court case and provide regulatory certainty during the **Gas Accord** period; (4) it would divest PG&E of gas gathering facilities; (5) it would phase out PG&E's core subscription service; and (6) it would assign EAD revenue shortfalls to PG&E.14. The **Gas Accord** has other features that oppose its approval: (1) it fails to resolve or mitigate PG&E's conflict between shareholder and customer interests; (2) roll-in of Line 401 rates is inefficient and contrary to incremental ratemaking principles; (3) roll-in of Line 401 rates could undermine future [*120] market tests for new capacity; (4) it provides few direct benefits for core customers; (5) it purports to settle Rule 1 allegations; (6) it does not reflect the interests of Southwest producers and pipeline companies; and (7) it holds uncertainty about disposition of Edison's side deal payment and other payments to PG&E.15. Taken as a whole, the benefits of the **Gas Accord** outweigh its problems, since the Commission's approval of the **Gas Accord** includes a discounting rule to address PG&E's conflict of interest and the Commission's approval would not preclude future Commission proceedings addressing PG&E's conflicts of interest.16. The **Gas Accord** is reasonable in light of the whole record and is in the public interest, since the Commission's approval of the **Gas Accord** includes a discounting rule to address PG&E's conflict of interest and the Commission's approval would not preclude future Commission proceedings addressing PG&E's conflicts of interest.17. PG&E may have misled the Commission and violated Commission rules by filing testimony about PG&E's reasons for constructing Line 401 which are inconsistent with the reasons given in the McLeod memo.18. PG&E warnings to PGT shippers [*121] that PG&E might not build matching capacity in California are inconsistent with PG&E's reliance on PGT commitments to justify building Line 401.19. Line 401 discounting limits do little to minimize stranded costs.20. In A.89-04-033, PG&E assured the Commission that existing gas customers that did not receive service over Line 401 would be insulated from any costs or risks associated with the expansion project.21. The meaning of PG&E's statements to the Commission is not ambiguous. No interpretation of the statements is necessary.22. Norcen's request for findings that PG&E deceived the market into becoming captive to PG&E's designs, which were antithetical to market signals, is not supported by the evidence and should be denied.23. Norcen's request for a Commission order requiring PG&E to accept permanent release of Norcen's contracted capacity on PGT and Canadian pipelines is not reasonable and should be denied.24. On July 1, 1997, the Commission's Consumer Services Division submitted its settlement with PG&E concerning PG&E's alleged Rule 1 violations, which provides that PG&E would pay $850,000 and require its professional level employees appearing before the CPUC to attend [*122] an ethics training course if the Commission approved the settlement.25. It is not necessary to defer approval of the **Gas Accord** in order to consider the upcoming Natural Gas Strategic Plan.26. Approval of partially rolled-in rates for noncore customers is reasonable, only because noncore representatives have agreed to it and because the **Gas Accord** continues to preserve vintaged Line 400 rates for PG&E's core customers.27. Employing a performance-based ratemaking mechanism does not remove a utility's procurement practices from the scrutiny of the Commission.28. Disallowances or penalties for behavior favoring shareholder interests at the expense of core customer interests are not limited to those accrued under the CPIM, and are not limited to scenarios in which Southwest is the lowest cost core supply.29. It would be unfair to allow PG&E to prop up the market clearing price for transportation into its service territory by refusing to discount Southwest to on-system service.30. The **Gas Accord** does not explicitly give PG&E discretion over discounting among competing services.31. All of the signatories to the **Gas Accord** have authorized representatives to state that they support [*123] or do not oppose an amendment to the **Gas Accord** which requires PG&E to offer commensurate discounts to shippers on Line 300 and the California Gas Production Path whenever PG&E offers discounts on its Line 400/401.32. It is necessary for the Commission to adopt a commensurate discount rule that will mitigate the conflict between shareholder and noncore customer interests and will allow fair competition between Canadian, Southwest, and California gas supplies.33. It is necessary for the Commission to continue its oversight over PG&E's discounting practices in order to determine whether the commensurate discount rule has been circumvented or proves to be insufficient as a remedy for PG&E's conflict of interest.34. The ratemaking treatment of Edison's $80 million side deal payment to PG&E is uncertain under the **Gas Accord** and will need to be clarified and resolved after PG&E files an advice letter.35. Regarding revenue shortfalls associated with distribution service discounts, PG&E's motion for the adoption of the **Gas Accord** makes clear that PG&E's shareholders should be at risk for the revenue shortfalls unless PG&E overcomes a strong presumption and establishes that the discounts [*124] were reasonable.36. The Joint Recommendation is described in Appendix D to this decision.37. The Joint Recommendation has three features that support its approval: (1) it would allow market forces to set Line 300 prices; (2) it would keep the net costs of Southwest gas low; and (3) it would retain incremental ratemaking for Line 401.38. The Joint Recommendation has two features that oppose its approval: (1) it would be a step away from unbundled rates; and (2) it would set prices for Line 300 and Line 400 inconsistently.39. Under market-based pricing of utility services, rate certainty becomes a service attribute with market value.40. Under the Joint Recommendation, the move away from unbundled rates is not reasonable and cannot be balanced against the benefits of the agreement.41. The Joint Recommendation is not reasonable in light of the whole record and is not in the public interest.42. By exercising market power in setting Line 401 prices that compete against brokered Southwest capacity, and in pursuing shareholder benefits through backbone credit transactions, PG&E has imprudently placed shareholder interests above original system ratepayer interests.43. PG&E senior managers [*125] have failed the Commission's best efforts standard for marketing of unused interstate pipeline capacity, have relied on market power to the detriment of ratepayers, have failed to recognize the importance of PG&E's conflict of interest, and have failed to resolve the conflict of interest in a reasonable manner.44. Relief from 50% of noncore ITCS charges, 100% of core ITCS charges, and 100% of backbone credit charges under the **Gas Accord** is fair compensation to customers for past harm caused by PG&E's conflict of interest.45. The requests of El Paso and the Joint Recommendation sponsors to establish an IPO should be rejected without prejudice to further consideration by the Commission.46. El Paso's request that PG&E be ordered to divest its interstate and intrastate gas transmission facilities should be denied without prejudice.47. Municipal utility rate parity is beyond the scope of the record in the Line 401 general rate case.48. Transportation service priority for non-utility gas storage providers is beyond the scope of the record in the Line 401 general rate case.

Conclusions of Law1. The record supporting this opinion was submitted for Commission decision on December [*126] 31, 1996.2. PU Code § 1708 and the discovery of new evidence provide ample authority and justification for reopening PG&E's decision to construct Line 401.3. Approval of the **Gas Accord** should be granted without precluding in any way the Commission from further considering conflict of interest, affiliate abuse, and unbundling issues in other proceedings.4. Approval of the **Gas Accord** does not bind future Commissions or prohibit future Commission orders that might rescind, alter, or amend the terms of settlement.5. PG&E should be ordered to file quarterly and annual core procurement reports after one year of operations under the **Gas Accord.**6. The Commission should adopt a commensurate discount rule that will mitigate PG&E's conflict between shareholder and noncore customer interests and will allow fair competition between Canadian, Southwest, and California gas supplies.7. Imposition of a commensurate discount rule as an amendment to the **Gas Accord** is authorized under Rule 51.7 of our Rules of Practice and Procedure, because the parties to the **Gas Accord** have accepted this amendment.8. The Commission should continue its oversight over PG&E's conflict of interest by including a [*127] discount reporting requirement in PG&E's market assessment report which should be filed and served by March 1, 1999.9. Approval of the Joint Recommendation should be denied.10. Amortization of PG&E's ITCS and backbone credit accounts is subject to reasonableness review.11. NCPA's request for municipal utility rate parity should be denied.12. SoCalGas' request for transportation service priority for non-utility gas storage providers should be denied.13. The Rule 1 Settlement should be granted because it is reasonable in light of the whole record, it is consistent with law, and it is in the public interest.14. Good cause exists to waive the comment periods under Rule 51.4 of our Rules of Practice and Procedure in order to expeditiously rule on the Rule 1 Settlement since private parties, other than the alleged wrongdoers, have no right to participate in the settlement of Rule 1 violations.15. This order should become effective today, to expedite implementation of the **Gas Accord.SIXTH INTERIM ORDER**

IT IS ORDERED that:1. The request of Norcen Energy Resources Limited (Norcen) for findings that PG&E deceived the market into becoming captive to PG&E's designs is denied. [*128] 2. The request of Norcen for a Commission order requiring PG&E to accept permanent release of Norcen's contracted capacity on Pacific Gas Transmission Company and Canadian pipelines is denied.3. The **Gas Accord** is amended, with the consent of the parties to the **Gas Accord,** to include the following commensurate discount rule: whenever PG&E offers any shipper a discount on its Line 400/401, PG&E is required to contemporaneously offer a commensurate discount to all shippers for similar services on its Line 300 and its California Gas Production Path.4. The requests for approval of the **Gas Accord** contained in Application (A.) 96-08-043 and in PG&E's August 21, 1996, motion filed in these consolidated proceedings, are granted subject to the commensurate discount rule as an amendment to the **Gas Accord.** The approval of the **Gas Accord** is based, in part, upon PG&E's representations and commitments to forego recovery of the disallowed amounts ordered by D.94-03-050 and to forego its federal district court challenge to D.94-03-050 (in N.D. Cal. Civil No. 94-4381). PG&E must implement the commensurate discount rule when it implements the other provisions of the **Gas Accord.**5. The request for [*129] approval of the Rule 1 Settlement in its entirety is granted, and under Rule 87 of our Rules of Practice and Procedure we waive the comment periods of Rule 51.4 of our Rules of Practice and Procedure.6. In its operations under the **Gas Accord,** PG&E shall not favor shareholder interests at the expense of core customer interests in execution of the adopted core procurement incentive mechanism, or in situations in which Southwest is the lowest cost core supply, or in interstate gas transactions with affiliated pipelines, or in dealing with affiliates or subsidiaries in general.7. PG&E's shareholders shall bear all revenue shortfalls from future transmission rate discounts and there is a strong presumption that PG&E's shareholders should bear all revenue shortfalls from future distribution rate discounts, if any.8. PG&E's request in A.94–06–044 to amortize in rates the amounts in its interstate transition cost surcharge (ITCS) account is granted, pursuant to the terms of the **Gas Accord.**9. PG&E's request to amortize in rates the amounts in its backbone credit account is denied, pursuant to the terms of the **Gas Accord.**10. Within 30 days after the completion of one year of operating experience [*130] under the **Gas Accord,** PG&E shall file quarterly and annual reports on core procurement operations.11. On or before March 1, 1999, PG&E shall file with the Energy Division with service to all parties on the **Gas Accord** service list in A.92–12–043 et al., a market assessment report that covers pipeline system operations from the implementation date of the **Gas Accord** through the end of 1998. This market assessment report must include a detailed and meaningful report of PG&E's discounts for its transportation on Line 401, Line 400/401, Line 300 and the California Gas Production Path, and of PGT's discounts for its transportation to California and/or to the Malin delivery point.12. The September 24, 1996, motion of the Department of General Services of the State of California; the Department of Energy, Minerals & Natural Resources and the State Land Office of the State of New Mexico (New Mexico); and The Utility Reform Network (TURN) for approval of their Joint Recommendation is denied.13. The requests of TURN and El Paso Natural Gas Company (El Paso) that PG&E be denied the authority to discount Line 401 rates are denied.14. TURN's proposal that direct connection rates include social [*131] and transition costs is denied without prejudice.15. TURN's request to limit Line 401 backhaul service to periods when Line 300 is full is denied without prejudice.16. The requests of El Paso and New Mexico to eliminate PG&E's use of minimum bids for brokered capacity are denied without prejudice.17. The requests of El Paso and the Joint Recommendation sponsors to establish an independent pipeline operator are denied without prejudice.18. El Paso's request that PG&E be ordered to divest its interstate and intrastate gas transmission facilities is denied without prejudice.19. The request of Northern California Power Agency for orders regarding municipal utility rate parity is denied without prejudice.20. The request of Southern California Gas Company for orders regarding transportation service priority for non–utility gas storage providers is denied without prejudice.21. Within 45 days after the effective date of this decision, PG&E shall file revised tariff sheets as necessary to implement the above ordering paragraphs, including the commensurate discount rule.22. The revised tariff sheets shall comply with General Order 96–A and shall apply to service rendered on or after [*132] their effective date.23. The tariff revisions shall not become effective until after the Commission approves the advice letter filings.This order is effective today.Dated August 1, 1997, at San Francisco, California.**APPENDIX A**Additional Appearances

Protestants: Roxanne Armstrong and Robert B. Keeler, Attorneys at Law, for Apache Canada and DEK Energy Company.

Interested Parties: Jonathan Abram and Kevin Lipson, Attorneys at Law, for Southern California Edison Company; Tom Beach, for the SEGS Projects (Daggett Leasing Corp., and The Harper Lake Companies); Jay Cattermole, for National Gas & Electric L.P.; Lynn Haug and Doug Kerner, Attorneys at Law, for Independent Energy Producers Association; Aldyn Hoekstra, for Cambridge Energy Research Associates; Richard Ishikawa, for Southern California Gas Company; Joseph M. Karp, Attorney at Law, for California Cogenerating Council; Carolyn Kehrein, for Energy Management Services; David McAndrew, for Defense Fuel Supply Center; William Robey, for CRSS, Inc.

Information Only: Cyril Penn, for California Energy Markets.

State Service: Harvey Morris, Attorney at Law, Legal Division; Robert [*133] L. Strauss, Energy Division.Substitute Appearances

Interested Parties: Richard M. Blumberg, Attorney at Law, for Burlington Resources Oil & Gas Company; Evelyn Elsesser, Attorney at Law, for Amoco Production Company, Amoco Energy Trading, and Indicated Producers; James W. McTarnaghan, Attorney at Law, for Enron Capital and Trade Resources, Wild Goose Storage, Inc., and Kern River Gas Transmission Company; Douglas Porter, Attorney at Law, for Southern California Edison Company.APPENDIX BSubject to Rule 51 of the CPUC Rules of Practice and Procedure, Rule 601 et seq. of the FERC Rules of Practice, Rule 408 of the Federal Rules of Evidence, and Section 1152 of the California Evidence Code**PACIFIC GAS AND ELECTRIC COMPANYAPPENDICES TO THE REPORT ON THE GAS ACCORD SETTLEMENT AGREEMENTAPPENDIX 1GAS ACCORD SETTLEMENT AGREEMENTAUGUST 21, 1996THE GAS ACCORD SETTLEMENT AGREEMENT**

I. INTRODUCTIONA. Proposal for a New Gas Market Structure for Northern California

The **Gas Accord** is a proposal to significantly restructure the way PG&E provides natural gas service to California consumers by increasing competition and customer [*134] choice. In part, the **Gas Accord** is a response to signals from regulators and the market that the time has come for such changes. The **Gas Accord** is also a vision of how the natural gas industry in northern California should be structured as we enter the next century.

The **Gas Accord** consists of three broad initiatives. First, the Accord unbundles PG&E's gas transmission and a portion of storage services, places PG&E at risk for these costs, and changes the terms of service and the rate structure for gas transportation so that customers' rates more accurately reflect the facilities used to serve them. PG&E's service area is served by an integrated high-pressure transmission system that resembles an interstate pipeline system more than a typical local distribution company (LDC) system. The Accord unbundles the transmission system, and requires PG&E to operate and provide service on that system similar to an interstate pipeline. PG&E will continue to provide distribution service, much as it does today.

Second, the Accord changes PG&E's role in procuring gas supplies for core customers in order to increase customer choice. It reduces PG&E's role in core procurement, and reduces PG&E's [*135] holdings of interstate transportation capacity. It also provides for negotiations between PG&E and California gas producers for a mutual release of supply contracts with PG&E. PG&E's core procurement department will continue to hold a portion of storage capacity to ensure system reliability and a defined standard of customer service reliability, but customers will be free to seek commodity and transmission services from alternative suppliers. As part of this Agreement, the Core Procurement Incentive Mechanism agreed to by PG&E and DRA in 1996 must be implemented for an initial period through 1997, followed by the revised incentive mechanism described in the **Gas Accord** for the period thereafter. The **Gas Accord** period will extend from the date of implementation, which PG&E is asking to be July 1, 1997, through December 31, 2002.

Third, the **Gas Accord** settles all major outstanding gas regulatory issues. Neither PG&E, the CPUC, nor market participants can expend the energy and resources to proceed with the **Gas Accord** while at the same time arguing about whether PG&E acted reasonably under the old rules.

The changes proposed herein are reasonable and bold responses to several forces [*136] for change that have manifested themselves since gas restructuring began in California, about ten years ago. On the regulatory side, the CPUC has initiated programs to segment the noncore from the core market, with rights accorded to noncore customers to obtain transmission service and commodity supplies separately from bundled PG&E service. Core customer representatives are now advocating an increase in the competitive choices available to them. In addition, the CPUC has changed the way it regulates both Southern California gas utilities, approving performance-based regulation for each utility's gas procurement. The CPUC also has called for an OII/OIR for the purpose of further restructuring the California natural gas industry on at least two occasions, most recently in a decision (D.94-02-042) approving interim rates for PG&E's Pipeline Expansion Project.

The market, too, has signaled a desire for change. Customers have sought more options for natural gas transportation and sources of supply. Marketers and producers have stated there are obstacles to selling directly to core customers, and there have been proposals to build competitive pipelines into PG&E's service area. All of [*137] these demonstrate that PG&E's current transportation and service structure is outdated.

For these reasons, further changes are inevitable. PG&E could resist and watch these changes occur piecemeal, to the possible disadvantage of its customers and shareholders; however, this **Gas Accord,** negotiated with the market participants, offers a better prospect for a rational result. All participants in the Accord process — market participants, the CPUC, and PG&E — have significant interests in the process of change. It is vital that this process result in a fair resolution of past issues and a fair opportunity to compete in the new world of unbundled competitive gas markets.

Unbundling of services will increase market participation. Each competitive market — transmission, procurement, and other services — inevitably will lead to the development of new services and increased choices for consumers. As these markets become contested by new service providers, the freedom to compete in each on an equal basis must be granted to all parties, including PG&E. The Accord will move PG&E and the marketplace toward this vision.

The Accord is a negotiated compromise on a number of issues related [*138] to many proceedings. If not accepted by the Commission, the Accord shall not be admissible in evidence in this or any other proceeding. Nothing contained herein shall be deemed to constitute an admission or an acceptance by any party of any fact, principle, or position contained herein.

The Accord is to be treated as an entire package and not as a collection of separate agreements on discrete proceedings, nor is the restructuring proposal separable from the resolution of past issues. To accommodate the interests of different parties on diverse issues, changes, concessions, or compromises in one section of the Accord necessitated changes, concessions, or compromises in other sections.

In an August 16, 1995, Assigned Commissioner's Ruling on the **Gas Accord** process, Assigned Commissioner Fessler stated:

> I encourage all affected parties to participate in settlement discussions, and I encourage PG&E to include all gas market participants in its negotiations. I look with disfavor on parties that decline fair opportunities to participate in settlement discussions, then criticize agreements reached in their absence. (August 16, 1995, ACR, p. 5).

The **Gas Accord** negotiations have [*139] met the Assigned Commissioner's standard for wide participation, and the Accord presents a new, more competitive structure for the natural gas marketplace in northern California that is broadly supported by the market participants. The settling parties encourage the Commission to adopt and implement the **Gas Accord.**

B. Elements of the Agreement

1. Unbundle the rates and service options for transmission system service from distribution system service. The transmission system is defined as PG&E's backbone and local gas transmission lines, including gathering and Stanpac facilities. The local transmission system includes distribution feeder mains (DFMs). A map of PG&E's system is included at the end of this Section.

2. Charge transmission, storage, and distribution rates to those customers who use these facilities pursuant to contractually–defined terms of service.

3. Provide balancing service through a single integrated gas system for both transmission level and distribution level customers. PG&E proposes initially to continue a monthly balancing service, with imbalance trading, tighter tolerance bands and monthly cash–out provisions.

4. Establish transmission system [*140] services that eliminate the crossover ban and the backbone credit.

5. Offer various paths over the transmission system. Each path requires a separate contract. See Section II for more information on the definition of the paths and applicable delivery and receipt points. These paths include:

   a. Malin to On–system for the Core;

   b. Malin to On–system;

   c. Topock to On–system;

d. California Production and Storage to On–system;

e. Malin to Off–system;

f. Topock to Off–system;

g. California Production, Storage, Market Center/Hub Services, and On–system Delivery Points to Off–system; and

h. G–XF Firm Service.

On–system is defined as any point at which deliveries are made to, or for ultimate delivery to, PG&E's distribution facilities, PG&E's storage facilities, a third party's storage facilities located in PG&E's service territory, or end–use or wholesale loads located in PG&E's service territory. Off–system is defined as any point of interconnection for delivery outside of PG&E's service territory.

6. Provide new services over these paths using (a) Line 300 capacity, and (b) capacity consisting of that portion of Line 400 capacity not reserved for the core and that [*141] portion of Line 401 capacity not reserved under long–term firm contracts with existing firm Expansion shippers. This combined Malin capacity is to be redesignated by the Commission as non–Expansion capacity, which shall be subject to phased–in rates and shall not be subject to the tariff or contract provisions and rights that apply to the Line 401 capacity reserved under long–term Expansion contracts.

7. For ratemaking purposes, phase–in the embedded cost of 375 MMcf/d (381 Mdth/d) of Line 401 capacity into the Line 400 capacity not reserved for the core over the period from 1997 through 2002. The phase–in will begin at 200 MMcf/d (203 Mdth/d). This phase–in schedule is consistent with historical Line 401 on–system usage and projected on–system noncore demand growth. This will determine the Malin to on–system path costs. (See Section II.I.3 for the complete phase–in schedule.)

8. Provide to the retail core 600 MMcf/d (609 Mdth/d) and to core wholesale 6.5 MMcf/d (6.6 Mdth/d) of Malin to on–system vintage firm capacity, at Line 400 embedded cost (vintaged rates). Any additional capacity from Malin used by the retail core or wholesale customers must be on the Malin to on–system [*142] path.

9. Honor the service commitments set forth in existing long–term transmission service agreements for the period of the Accord or the remaining term of each such agreement, whichever applies. These commitments are addressed below in Section II.F.

10. Provide parking and lending services at all interstate interconnection points and at Kern River Station. These services shall be provided using transmission and storage capacity as it becomes available.

11. Continue operational integration of PG&E's gas storage facilities with PG&E's transmission facilities. PG&E will reserve firm storage capacity for pipeline balancing services and PG&E's Core Procurement Department will contract for a major portion of PG&E firm storage capacity on behalf of the retail core. The remaining storage capacity will be marketed in an unbundled storage program.

12. Unless otherwise stated in this document, the principles and specific elements of the Accord, the resulting Accord rates (and their underlying assumptions) and the revenue treatment for Accord services are fixed and not subject to challenge or change in any regulatory forum during the **Gas Accord** period. Consequently, the parties will [*143] not challenge any assumption that is set by this Accord, and that if altered, would result in a shift of revenue responsibility between core and noncore customers and/or between customers and PG&E shareholders. Furthermore, any issue settled as part of the **Gas Accord** described in Section V, Litigation Resolution, will not be subject to litigation in any regulatory forum.

[SEE PG&E's Gas Transmission Facilities IN ORIGINAL]

II. TRANSMISSION STORAGE SERVICESA. New Transmission Services

The services offered over the backbone portions of the new transmission paths (paths a through g, listed in Section I.B.5 above) are described below. Contracts will set the terms of service, including service priority. Local transmission costs are included in a separate local transmission charge, which will be collected from all on–system end–users. The pre–existing transmission services are described in Section II.B, below.

The following five transmission services will have all terms and conditions set by tariff.

1. Firm Annual On–system (AFT)

a. Definition: Firm service on the transmission system with deliveries on–system.

b. Minimum Term: One year.

c. Rate: Straight [*144] Fixed Variable (SFV) or Modified Fixed Variable (MFV), at the shipper's option for the backbone component. See rates in Section VI. No discounts.

2. Firm Seasonal (SFT)

a. Definition: Firm seasonal service on the transmission system.

b. Conditions: Paths to on–system destinations only. Maximum term limited to two years.

c. Minimum Term: Three consecutive months in one season.

d. Winter Season: November through March.

e. Summer Season: April through October.

f. Rate: SFV or MFV, at the shipper's option for the backbone component. See rates in Section VI. No discounts.

3. As–available On–system (AA)

a. Definition: As–available service on the transmission system with deliveries on–system.

b. Minimum Term: One day.

c. Rate: Volumetric for the backbone component. See rates in Section VI. No discounts.

4. Firm Annual Off–system (AFT–Off)

a. Definition: Firm service on the transmission system with deliveries off–system.

b. Minimum Term: One year.

c. Rate: Straight Fixed Variable (SFV) or Modified Fixed Variable (MFV), at the shipper's option for the backbone component. If a shipper elects SFV rate design, [*145] the shipper can also specify an alternate delivery point on–system. If a shipper elects MFV, delivery must be off–system only. See rates in Section VI. No discounts.

5. As–available Off–system (AA–Off)

a. Definition: As–available service on the transmission system with deliveries off–system.

b. Minimum Term: One day.

c. Rate: Volumetric for the backbone component. See rates in Section VI. No discounts.

The following four transmission services are negotiable, as indicated.

6. Negotiated Firm Service On–system (NFT)

a. Definition: Firm service on the transmission system with deliveries on–system.

b. Minimum Term: Negotiable.

c. Rate: Negotiable, above a marginal–cost–based floor consistent with negotiated term. Maximum rate for the backbone component of each path is 120 percent of the firm annual rate for that path.

d. Take Requirement: Negotiable.

e. Sections IX and X of General Order No. 96–A are waived by the Commission.

7. Negotiated As–available On–system (NAA)

a. Definition: As–available service on the transmission system with deliveries on–system.

b. Minimum Term: Negotiable.

c. Rate: Negotiable, [*146] above a marginal–cost–based floor consistent with the negotiated term. Maximum rate for the backbone component of each path is 120 percent of the As–available rate for that path.

d. Take Requirement: Negotiable.

e. Sections IX and X of General Order No. 96–A are waived by the Commission.

8. Negotiated Firm Service Off–system (NFT–Off)

a. Definition: Firm service on the transmission system with deliveries off–system.

b. Minimum Term: Negotiable.

c. Rate: Negotiable, above a marginal–cost–based floor consistent with negotiated term. Maximum rate for the backbone component of each path is 120 percent of the firm annual rate for that path.

d. Take Requirement: Negotiable.

e. Sections IX and X of General Order No. 96–A are waived by the Commission.

9. Negotiated As–available Off–system (NAA–Off)

a. Definition: As–available service on the transmission system with deliveries off–system.

b. Minimum Term: Negotiable.

c. Rate: Negotiable, above a marginal–cost–based floor consistent with the negotiated term. Maximum rate for the backbone component of each path is 120 percent of the As–available rate for that path.

d. Take Requirement [*147] : Negotiable.

e. Sections IX and X of General Order No. 96–A are waived by the Commission.

10. PG&E may also offer other customer–specific negotiated contracts. Negotiated transmission service contracts under NFT and NAA will not require submission to the CPUC for approval; however, any other negotiated transmission service contracts will require submission to the CPUC for approval.

11. The following table summarizes which new transmission services are available to the transmission paths described in Section I.B.5.

Path	Available Services
a. Malin to On–system for Core	AFT
b. Malin to On–system	AFT, SFT, AA, NFT, NAA
c. Topock to On–system	AFT, SFT, AA, NFT, NAA,
d. California Production and Storage to On–system	AFT, SFT, AA, NFT, NAA,
e. Malin to Off–system	AFT–Off, AA–Off, NFT–Off, NAA–Off
f. Topock to Off–system	AFT–Off, AA–Off, NFT–Off, NAA–Off
g. California Production, Storage, Market Center/Hub Services and On–system Delivery Points to Off–system	AFT–Off, AA–Off, NFT–Off, NAA–Off

B. Pre–existing Transmission Services

1. G–XF Firm Service

a. Definition: Firm service on Line 401 under the G–XF rate.

b. Minimum Term: Thirty [*148] years.

c. Rate: Incremental rates based on a capital cost for Line 401 of $736 million, using utility capital structure and the operating expenses and cost allocation methodologies set forth in PG&E's PEPR Application.

d. Take Requirement: As negotiated.

e. Other terms and conditions: Delivery point as set forth in Exhibit A to each firm contract;

Uniform Terms of Service rights apply only to firm G-XF service; backbone credit and crossover ban are eliminated.

f. Sections IX and X of General Order No. 96-A may apply.

2. Expedited Application Docket (EAD) Agreements

a. Definition: Firm service on Line 300 and from California gas production to the burnertip, under individually negotiated contracts approved by the CPUC under the provisions of Decision 92-11-052.

b. Minimum Term: As set forth in each contract.

c. Rate: Volumetric negotiated rate, as set forth in each contract.

d. Take Requirement: As set forth in each contract.

e. Other terms and conditions: As set forth in each contract.

f. Sections IX and X of General Order No. 96-A may apply.

3. Enhanced Oil Recovery (EOR) Agreements

a. Definition: Interruptible [*149] service for Enhanced Oil Recovery customers pursuant to Decisions 85-12-102 and 87-05-046.

b. Minimum Term: As set forth in each contract.

c. Rate: Volumetric negotiated rate, as set forth in each contract.

d. Take Requirement: None

e. Other terms and conditions: As set forth in each contract.

f. Sections IX and X of General Order No. 96-A apply.

4. Expedited Direct Connection Docket (EDCD) Agreements

a. Definition: Agreements for direct connection service on PG&E's Line 401 approved pursuant to the CPUC's Expedited Direct Connection Docket.

b. Term: The remaining term of the direct connection agreement.

c. Rate: The rate established in the direct connection agreement. If this agreement does not specify a rate, then the rate will be established under one of the new transmission service rates.

d. Other terms and conditions: Per the direct connection agreement, or if unspecified in that agreement, the applicable **Gas Accord** tariffs.

5. Other Existing Agreements

a. Negotiable Interruptible Agreements
PG&E has a number of negotiable interruptible transportation agreements with terms that may extend into the Accord period. [*150] PG&E will continue to honor the terms and conditions,

including the rate, negotiated for the original term of these contracts.

b. Crockett Cogeneration
Crockett cogeneration has a negotiated contract which provides for transportation service at volumetric rates. PG&E will continue to honor the terms and conditions, including the rate, negotiated for the original term of this contract. If any terms and conditions are unspecified by the existing contract agreement, then the applicable **Gas Accord** tariffs will apply.

C. Storage Services

1. Storage Capacity Allocated To Core Customers, Including Core Transport Customers

a. Core service is allocated a portion of storage capacity to support the obligation to maintain highly reliable service under cold conditions. See Section II.E.5 for allocations.

b. Core aggregators, on behalf of their core transport customers, will be allocated a pro rata share of the total core reservation based on the winter season throughput of their core customers.

c. Costs for storage allocated to core customers, including core transport customers, will remain bundled in all core rates.

d. Any storage capacity that is not needed for core reliability [*151] may be brokered.

e. PG&E and core aggregators, on behalf of core customers, may elect to purchase more storage through the unbundled storage program.

2. Storage Capacity Allocated to Pipeline Balancing Services

a. A portion of storage capacity is needed to support the balancing services. See Section II.E.5 for the allocation.

b. Storage costs allocated to balancing services remain bundled in transmission rates.

3. Unbundled Storage Program

a. PG&E will offer storage services to the market from its integrated storage facilities through the unbundled storage program. The storage services will be offered from the capacity remaining, after the allocations for balancing provisions and storage for the core market.

b. Firm Storage Service (FS)

i. Definition: Firm storage service.

ii. Minimum Term: One year

iii. Rate: Sub-functions are capacity (combined injection and inventory) and withdrawal. Each sub-function is further divided into a reservation charge (fixed) component and a volumetric charge (variable) component.

iv. Conditions: Requires injection during the defined summer storage season.

v. Features: Imbalance trading and inventory [*152] transfers are available.

c. Negotiated Firm Storage Service (NFS)

i. Definition: Firm storage service; customers may purchase inventory, injection, and withdrawal separately.

ii. Minimum Term: One month

iii. Rate: The flexibility inherent in this storage offer could result in stranded facilities and PG&E requires the opportunity to collect the value of its storage services. Rates are negotiable above a short-run marginal price floor and capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program for each of the three storage subfunctions (e.g., inventory, injection, or withdrawal).

iv. Features: Imbalance trading, inventory transfers, and counter-cyclical operations are available.

v. Sections IX and X of General Order No. 96-A are waived by the Commission.

d. Negotiated As-available Storage Injection and Withdrawal Service (NAS)

i. Definition: As-available storage service only available to customers with firm storage inventory.

ii. Minimum Term: One day

iii. Rate: Volumetric only rate design. The flexibility inherent in this storage offer could result in stranded facilities [*153] and PG&E requires the opportunity to collect the value of its storage services. Rates are negotiable above a marginal price floor and capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program for each of the three storage subfunctions (e.g., inventory, injection, or withdrawal).

iv. Sections IX and X of General Order No. 96-A are waived by the Commission.

4. PG&E may also offer other customer-specific negotiated contracts. Negotiated storage service contracts under NFS and NAS will not require submission to the CPUC for approval; however, any other negotiated storage service contracts will require submission to the CPUC for approval.

5. Depending on market interest, PG&E is free to develop and offer additional storage services in the future.**D. Other Services**

1. Parking (PARK) Services offered are identical to those approved by the CPUC on June 26, 1996 (Advice 1949-G).

a. Definition: As-available short-term parking service, using PG&E's transmission and storage system.

b. Term: One day to one year.

c. Rate: Negotiable, above a minimum transaction fee and capped at the daily and/or [*154] annual cost to cycle gas using Firm Storage Service.

d. Terms and Conditions: Gas is parked and unparked at the same location.

e. Priority: Lowest priority As-available service.

2. Lending (LEND) Services offered are identical to those approved by the CPUC on June 26, 1996 (Advice

1949-G).

a. Definition: As-available short-term loan of gas using PG&E's transmission and storage system.

b. Term: One day to one year.

c. Rate: Negotiable, above a minimum transaction fee and capped at the daily and/or annual cost to cycle gas using Firm Storage Service.

d. Terms and Conditions: Gas is loaned and repaid at the same location.

e. Priority: Lowest priority As-available service.

3. PG&E may also offer other customer-specific negotiated contracts. Negotiated service contracts under PARK and LEND will not require submission to the CPUC for approval; however, any other negotiated service contracts will require submission to the CPUC for approval.

4. Other

Depending on market interest, PG&E is free to develop and offer various additional services in the future.

E. General Terms and Conditions

1. These general terms and conditions [*155] will apply to PG&E's intrastate transmission and storage systems, and to third party storage providers located in PG&E's service territory who have an operating agreement and who have inter-connecting facilities with PG&E. Subscription to these services does not, in itself, subject the subscriber to CPUC jurisdiction.

2. With the unbundling of transmission services, the crossover ban and the backbone credit are eliminated. The following sections in PG&E's existing tariffs are removed along with other references and definitions as may be applicable: Rule 21, Section H, "Scheduling Priority at Malin, Oregon"; Rule 21, Section I, "Self Identification of Malin, Oregon Receipts"; and Rule 22, "Backbone Credit Eligibility Criteria."

3. Receipt Points By Path

a. The receipt points by path are as follows:

Path	Receipt Points
Malin to On-system for the Core	Malin
Malin to On-system	Malin
Topock to On-system	Topock, Daggett, and Kern River Station
California Production and Storage to On-system	PG&E interconnections with California gas production within PG&E's service territory, PG&E's storage facilities, or a third party's storage facilities located in PG&E's service territory.
Malin to Off-system	Malin
Topock to Off-system	Topock, Daggett, and Kern River

Path	Receipt Points Station
California Production, Storage, Market Center/Hub Services, and On–system Delivery Point Pools to Off–system	PG&E interconnections with California gas production within PG&E's service territory, PG&E's storage facilities, a third party's storage facilities located in PG&E's service territory, PG&E's Market Center/Hub Services, or on–system delivery point pools.
G–XF Firm Service	Malin

[*156]
b. Alternate Receipt Points
Alternate receipt points are allowed only within the transmission path contracted for by a shipper.

c. New Receipt Points
New receipt points may be requested from time to time by shippers.

4. Delivery Points

a. On–system Deliveries
On–system is defined as any point at which deliveries are made to, or for ultimate delivery to, PG&E's distribution facilities, PG&E's storage facilities, a third party's storage facilities located in PG&E's service territory, or end–use or wholesale loads located in PG&E's service territory.

b. Off–system Deliveries
Any interconnection for delivery outside of PG&E's service territory, including Topock, Daggett, Kern River Station, Malin, etc.

c. G–XF Firm Service
Delivery points are as specified in each shipper's FTSA (Exhibit A).

5. Initial Allocation of Firm Intrastate Transmission Capacity

a. Total intrastate capacity currently available for firm transmission services is:

	MMcf/d	Mdth/d
Malin:	1,803	1,830
Topock:	1,140	1,174
California Gas	200	192

The Malin capacity consists of 990 MMcf/d (1,005 Mdth/d) from Line 400 and 813 MMcf/d (825 Mdth/d) from Line 401.

b. PG&E's retail [*157] core initially will be allocated the following quantities of firm transmission capacity:

		Malin to On–system	Topock to On–system	California
Annual	MMcf/d	600	150	50
	Mdth/d	609	155	48

c. PG&E's retail core will also hold additional seasonal winter capacity as follows:

	Malin to On–system	Topock to On–system	California
November and March			
MMcf/d	0	150	0
Mdth/d	0	155	0
December to February			
MMcf/d	0	450	0
Mdth/d	0	464	0

d. The retail core capacity reservation on the Topock to on–system path (Line 300) and the California path can be modified in ensuing BCAPs to account for changes in core requirements due to factors such as core aggregation, the termination of PG&E's California gas contracts, and the migration of core customers to noncore status. These modifications will not take place prior to 2000.

e. Capacity of up to 6.5 MMcf/d (6.6 Mdth/d) is available on the Malin to on–system path for existing wholesale customers on behalf of their core load.

f. New services over the Malin paths will use capacity consisting of that portion of Line 400 capacity (383.5 MMcf/d; 389 Mdth/d) not reserved for the core, including wholesale, [*158] and that portion of Line 401 capacity (509 MMcf/d; 517 Mdth/d) not reserved under long–term firm contracts with existing firm Expansion shippers. This combined capacity is to be redesignated by the Commission as non–Expansion capacity, which shall be subject to "phased–in" rates and shall not be subject to the tariff or contract provisions and rights (including but not limited to the firm Expansion shippers' "Uniform Terms of Service" rights) that apply to the Line 401 Expansion capacity reserved under long–term contracts.

g. PG&E will conduct an open season among all creditworthy parties to award remaining intrastate firm transmission service for at least the minimum term and at the full tariff rate under the AFT, AFT–Off, or SFT service. Firm capacity will first be awarded under the AFT and AFT–Off service. Any remaining firm capacity will then be awarded under the SFT service.

h. If a particular path is oversubscribed in the open season, PG&E will award available firm capacity based on PG&E's determination of the highest economic value of each bid to PG&E's gas transmission department, as determined by PG&E.

6. Allocation of Storage Capacity

a. The following quantities [*159] of firm storage capacity will be allocated to PG&E's retail core customers, including core transport:

Inventory	Injection	Withdrawal
32.8 Bcf	93 – 209 MMcf/d	951 – 1,228 MMcf/d
33.5 MMdth	95 – 213 Mdth/d	970 – 1,253 Mdth/d

b. The following quantities of firm storage capacity will be allocated to system load balancing:

Inventory	Injection	Withdrawal
2.2 Bcf	50 MMcf/d	70 MMcf/d
2.24 MMdth	51 Mdth/d	71 Mdth/d

c. The following quantities of storage capacity will be allocated to the unbundled storage program:

Inventory	Injection	Withdrawal
4.7 Bcf	13 – 30 MMcf/d	136 – 175 MMcf/d

Inventory	Injection	Withdrawal
4.79 MMdth	13 – 30 Mdth/d	139 – 179 Mdth/d

Volumes are subject to change pursuant to operating conditions. Future fluctuations or changes in PG&E's injection and/or withdrawal capabilities during the **Gas Accord** period will be assigned or absorbed by the unbundled storage program, except for changes in storage capabilities required on behalf of core customers served by PG&E.

d. PG&E will conduct an open season among all creditworthy parties to award remaining firm storage service for at least the minimum term and at the full tariff rate for Firm Storage Service.

e. If Firm [*160] Storage Service is oversubscribed in the open season, PG&E will award available firm storage capacity based on PG&E's determination of the highest economic value of each bid to PG&E's gas transmission department, as determined by PG&E.

7. Subsequent Allocation of Intrastate Transmission and Storage Capacity

a. After the open season for transmission and storage capacity, any remaining capacity will be available for subscription under the Firm, Negotiated Finn, or As–available services on an on–going basis.

b. Customers may request negotiated rates at less than maximum rates. PG&E will not be required to sell capacity to any shipper at less than the full tariff rate; however, at PG&E's sole option, capacity may be awarded based on offers that represent the highest economic value to PG&E, as determined by PG&E.

8. Contract Assignment

a. Unless the shipper's contract states otherwise, all transmission and storage contracts are assignable. Such assignments may consist of all or part of the shipper's contract quantity and all or part of the shipper's remaining contract term.

b. Contract assignments are subject to the following requirements:

i. Assignors must notify [*161] PG&E in advance of their assignments.

ii. The assignee must satisfy PG&E's creditworthiness requirements described in Section II.E.9. Alternatively, the assignor may, at its option, waive the creditworthiness requirements applicable to the assignee, in which case the assignor shall be secondarily liable for non–performance by the assignee. If an assignor exercises this option, it must demonstrate to PG&E's satisfaction that it remains creditworthy itself.

c. To encourage assignments and development of an active secondary market, PG&E will maintain a posting board similar to PG&E's existing "Energy Marketplace" that contract holders may use, at their option. PG&E is willing to work with others to establish new or modify existing mechanisms, including electronic bulletin boards, that encourage development of an active secondary market.

9. Creditworthiness

a. An entity requesting service must demonstrate creditworthiness before receiving service. Additionally, an entity receiving service under a long–term (one year or longer) contract may be subject to periodic re–evaluations of its creditworthiness.

b. An entity requesting service must provide the following to PG&E in [*162] order for PG&E to evaluate its creditworthiness:

i. Most recent annual report;

ii. Most recent SEC Form 10-K;

iii. If SEC Form 10-K is unavailable, substitute audited annual financial statements (including a balance sheet, income statement, and cash flow statement), or

iv. If audited financial statements are unavailable, substitute unaudited financial statements (including a balance sheet, income statement, and cash flow statement) accompanied by an attestation by the providing entity's Chief Financial Officer that the information reflected in the unaudited statements is true and correct and a fair representation of the entity's financial condition;

v. Most recent quarterly or monthly financial statements (including a balance sheet, income statement, cash flow statement, and contingencies).

c. PG&E will use the items above, in conjunction with the entity's service request or service level, to determine the maximum amount of credit PG&E can offer the entity.

d. If an entity is unable to demonstrate creditworthiness through the materials listed in Section b, PG&E may request additional evidence of creditworthiness, in which event the entity may elect to provide one [*163] of the following:

i. an irrevocable letter of credit in form, substance and amount satisfactory to PG&E;

ii. a guarantee, in form and substance satisfactory to PG&E, executed by a person PG&E deems to be creditworthy, of the entity's performance of its obligations to PG&E; or

iii. such other form of security as the entity may agree to provide and as may be acceptable to PG&E.

e. PG&E will treat all financial statements provided to it as confidential.

f. PG&E will continue to oversee aggregators' creditworthiness, pursuant to PG&E's Gas Rule 23 - Gas Aggregation Service for Core Transport Customers.

10. Priority of Service

a. The current Receipt Point Capacity Allocation rules will change to reflect the following priorities.

b. Scheduling Priority at Transmission Receipt Points (in the following order)

i. Firm Intrastate Transmission: All firm service at all receipt points on a defined transmission path is treated equally (pro rata allocation of nominations if necessary).

ii. As-available Intrastate Transmission: Scheduled according to contract price.

c. Scheduling Priority at Transmission Delivery Points (in the following order):

i. Firm Intrastate [*164] Transmission: All firm service at a given delivery point is treated equally (pro rata allocation of nominations if necessary).

ii. As-available Intrastate Transmission: Scheduled according to contract price.

d. Scheduling Priority To Storage for Injection

i. Transportation priority to storage is determined by the underlying intrastate transmission contract.

ii. Injection priority at PG&E's storage interconnection is determined by the storage contract:
. PG&E Firm Storage Service: All firm service treated equally (pro rata allocation of nominations if necessary).
. PG&E As-available Storage Service: Scheduled according to contract price.

e. Scheduling Priority From Storage for Withdrawal

i. Transportation priority from storage to the delivery point is determined by the underlying intrastate transportation contract.

ii. Withdrawal priority at PG&E's storage interconnection is determined by the storage contract.
. PG&E Firm Storage Service: All firm service treated equally (pro rata allocation of nominations if necessary).
. PG&E As-available Storage Service: Scheduled according to contract price.

f. Over-Nomination Provision
PG&E will develop a tariff [*165] provision to discourage nominations in excess of actual available supply (over-nomination) at a constrained receipt or delivery point.

11. Local Constraints

a. PG&E will take whatever steps it determines are operationally necessary in the event a constraint on local transmission or distribution threatens service to customers. This includes curtailment of noncore customers.

b. To the extent feasible, PG&E will use the transmission system diversion procedures to prioritize noncore customers in the affected service area.

c. In the event of an Emergency Flow Order (EFO) due to a local constraint, EFO penalties may apply, but involuntary diversion penalties will not apply.

12. Service Reliability and Diversion Procedures

a. When operational conditions exist such that supply is insufficient to meet demand and delivery to end-users is threatened, the diversion of supply may be used to ensure continued gas delivery to core end-users. EFO provisions will apply under these conditions (see Section II.E.13). If a noncore end-user's supply is diverted, either voluntarily or involuntarily, then that end-user must curtail its use of natural gas. If a core end-user's supply is diverted, [*166] then that customer must pay any penalties if it continues to use gas, as referenced later in this Section.

b. The following diversion procedures will apply to ensure service reliability to core end-users. PG&E's core procurement department and core aggregators, on behalf of core customers, will use:

i. their own firm capacity, to the extent possible;

ii. any available As-available capacity on the system at any receipt point; and

iii. available voluntary diversion of supply from noncore end-users or other transmission system shippers, at prices not to exceed the cost of involuntary diversion.

c. Involuntary diversion of gas supply on the transmission system will be used as a last resort to ensure service reliability for core end–users. Finn transportation to off–system is not subject to diversion. Diversion will occur in the following order:

i. Noncore supply scheduled under As–available transportation is diverted in order of contract transmission price and on a pro rata basis for all volumes with the same price. However, scheduled deliveries from storage using As–available transmission will be treated as the highest priority noncore firm transmission.

ii. Firm [*167] transportation to on–system noncore end–users.

d. Those receiving involuntarily diverted supply will be assessed a $50/Dth diversion usage charge in addition to a $50/Dth EFO curtailment noncompliance penalty, for a total noncompliance charge of $100/Dth. These revenues will be used first to pay diversion credits to those whose gas supply is involuntarily diverted. The remaining revenues will be returned to all customers in the customer class charge.

e. Firm transportation service customers whose gas supply is involuntarily diverted will receive a $50/Dth diversion credit.

f. As–available transmission service customers whose gas supply is involuntarily diverted will receive a diversion credit based on the current market price of the diverted supply.

13. Balancing Service

a. Basic Service

i. Balancing service will be provided on a monthly basis through a single integrated gas system for both transmission–level and distribution–level customers.

ii. All customers shall exercise best efforts to have daily gas receipts match daily gas usage.

iii. Monthly imbalances can be carried forward one month, not to exceed plus or minus five percent of the usage in the [*168] month in which the imbalance occurred, except as noted in items a.iv and d, below.

iv. If at any time the aggregate imbalance on PG&E's system (excluding the operation of the storage reserved for balancing) has exceeded plus or minus three percent of that month's aggregate deliveries (excluding gas scheduled for subsequent delivery off–system) for two months in the preceding 12 month period, then the imbalance carry–over allowance will be decreased one percent after a minimum of 30 days notice to the market. This provision can be used to lower the imbalance carry–over allowance no more than once in any 12 month period. The carry–over allowance will not be set below three percent without CPUC approval. All references in the **Gas Accord** to a five percent carry–over allowance and to the tiers for monthly imbalance cash–outs are intended and understood to be subject to change by operation of this provision.

v. Operational Flow Order (OFO) and Emergency Flow Order (EFO) provisions will be used to manage operational imbalances when necessary.

b. Customer Imbalances

i. Imbalances generally will be maintained at the delivery point. For deliveries made to on–system end–users, the [*169] end–user will be responsible for imbalances. For deliveries to storage and to off–system points, the transmission shipper will be responsible for imbalances.

ii. End-user imbalance accounts may be assigned to a third party.

iii. A third party may aggregate imbalance accounts.

c. Imbalance Trading

i. Monthly imbalance quantities may be traded with another entity.

ii. Imbalance quantities can only be traded with other imbalance quantities that occurred during the same calendar month. Trading between on-and off-system imbalances is not allowed.

iii. Any imbalance trade must move the trader's imbalance quantity toward zero, unless the imbalance resulting from the trade is within the range of plus or minus three percent.

iv. Imbalance trading into and out of storage will be available. Firm storage customers may use a PG&E (or other on-system storage provider's storage account subject to having an appropriate operational balancing agreement between PG&E and the other storage provider) to trade transportation imbalances, during the imbalance trading period, within operational limits.

d. Imbalance Charges and Cash-Out

i. Automatic cash-out of all commodity and transmission [*170] imbalances outside of allowed carry-forward quantity each month will occur. In-kind imbalance deliveries will not be included. Imbalance cash-outs will have a commodity and a transmission component. Monthly imbalance cash-out occurs after imbalance trading for the month is complete.

ii. Commodity cash-out prices for each month for each interconnect are based on the higher (for under-deliveries) or lower (for over-deliveries) of the following gas price indexes at PG&E interconnects (e.g. Malin, Topock) from public sources (e.g. Bloomberg, Gas Daily):
. Monthly index price;
. Under-deliveries: average of the five highest daily index prices during the month;
. Over-deliveries: average of the five lowest daily index prices during the month.

iii. The commodity cash-out index price for imbalances less than or equal to ten percent will weight the appropriate interconnect indices by the supply mix of all gas received by PG&E for on-system customers during the month in which the imbalance occurred. Imbalances greater than ten percent will be cashed-out based upon an index equal to the highest interconnect index price for under-deliveries and the lowest interconnect index price for [*171] over-deliveries, regardless of PG&E's supply mix.

iv. The commodity cash-out index price will be adjusted by the following percentages, according to the level of the actual monthly imbalance:

Monthly Imbalance Level	Over-delivery (OD) Purchase Dollars	Under-delivery (UD) Sale Dollars
+/-5% to +/-10%	95% weighted OD index	105% weighted UD index
>+/-10%	50% lowest index	150% highest index

v. Transmission service cash-out prices are based on the volumetric component of PG&E's standard tariff firm (MFV) and As-available transmission services. Over-deliveries will receive a transmission service credit based on the volumetric component of the appropriate firm transportation rate. Under-deliveries will be charged the appropriate rate for As-available service. The appropriate rate is determined by weighting the path specific rates by the supply mix of all gas received by PG&E for on-system customers during the month.

vi. PG&E gas purchases and/or sales associated with cash-outs will be accounted for separately from the core portfolio purchases.

vii. The intent of imbalance cash–outs is to create an economic disincentive for incurring cash–out unbalances. PG&E will file [*172] to revise the imbalance charges and cash–out options if the **Gas Accord** provisions do not accomplish this.

e. Operational Flow Order Provisions

i. System–wide, local, or customer–specific OFO provisions may be called to order out–of–tolerance customers to balance supply and demand daily, when operationally necessary. OFO provisions will require daily balancing and impose penalties for noncompliance.

ii. OFOs may be called if pipeline inventory exceeds or is forecast to exceed desired pipeline inventory by 200 MMcf/d, or is below or is forecast to be below desired pipeline inventory by 150 MMcf/d. Desired pipeline inventory in the winter is typically 4.2 Bcf and in the summer is typically 4.15 Bcf.

iii. PG&E will use multi–stage OFO provisions, which would provide a daily tolerance band ranging from plus or minus 25 percent to zero percent of actual daily usage.

iv. Multi–stage OFO non–compliance penalty provisions would range from $1/Dth to $25/Dth. The amount of the penalty will be announced prior to the enactment of each stage. The penalty will start at $1/Dth and only increase during an event if the response to the OFO is inadequate. Subsequent levels will be $5/Dth [*173] and $25/Dth, as needed to maintain pipeline system integrity. A specific customer may start at an elevated penalty level if that customer has a history of non–compliance.

v. An OFO will normally be ordered with at least twelve hours notice prior to the beginning of the gas day, or as necessary as dictated by operating conditions. Penalties will not be imposed with less than twelve hours notice.

vi. For each noncore end–user without telemetering, compliance with an OFO will be determined by comparing the end–user's supply against a 5:00 p.m. day–before PG&E forecast of the end–user's usage.

f. Emergency Flow Order Provisions

i. Emergency Flow Order conditions are defined to exist when a forecast or actual supply and/or capacity shortage threatens to affect the delivery to end–users.

ii. EFOs will have a zero percent tolerance (supply must be greater than or equal to usage) and a $50/Dth noncompliance penalty.

iii. For each noncore end–user without telemetering, compliance with an EFO will be determined by comparing the end–user's supply against a 5:00 p.m. day–before PG&E forest of the end–user's usage.

iv. If an involuntary supply diversion is called in conjunction [*174] with an EFO, an additional $50/Dth diversion usage charge will apply for a total potential noncompliance penalty of $100/Dth.

v. An EFO would normally be ordered following an OFO, but could also occur under an emergency operational condition. There is no required notice period for EFOs, however, PG&E will attempt to provide as much notification to customers as possible.

vi. PG&E reserves the right to implement other measures to ensure system integrity should the EFO actions not alleviate the emergency condition.

g. Other Operational Balancing Issues

i. Transmission–level end–users and distribution–level noncore end–users will be required to have daily metering.

ii. Telemetering will be installed on noncore customers' meters where it is cost–effective. These costs will not change the rates established by the **Gas Accord.**

iii. PG&E reserves the right to propose other measures to ensure system integrity should the OFO and/or EFO provisions not prove to be adequate.

iv. A load profile modeling tool will be developed to determine daily usage for PG&E's core procurement customers and core transport customers served by core aggregators in order to remove PG&E's core portfolio [*175] from providing a system balancing function, and to be able to hold PG&E's core procurement department to the same balancing and OFO provisions to which others are held.

v. The normal nomination deadline will be shifted to one day prior to gas flow at all receipt points where the upstream operator(s) will accommodate the shift.

vi. PG&E will allow same–day nominations, if necessary, and if upstream and downstream operator(s) are able to accommodate the practice.

14. Transmission Level End–Use Service

a. To be eligible for transmission–level end–use service, an end–user must:

i. Be a noncore customer,

ii. Be physically connected to the transmission system or have an annual load in excess of 3 million therms/year; and

iii. Elect to receive transmission level end–use service.

b. All on–system transmission–level end–users must pay local transmission charges.

c. All other end–users will be served at distribution tariff rates.

d. The definition of a noncore customer may be revisited in BCAPs during the Accord period.

15. Negotiated Contracts

a. Standard tariff rates and terms are available to all customers.

b. PG&E may distinguish between parties in [*176] offering negotiated rates by evaluating differences in circumstances and conditions, including but not limited to differences occurring upstream, downstream or at the customer's location, affecting either cost of service or the entities' market alternatives. Such negotiations will be conducted without undue preference or undue discrimination.

c. Negotiated rates for transmission and storage service shall not be less than PG&E's short–run marginal cost of providing the service. Negotiated transmission rates under NFT and NAA will be capped at 120 percent of the tariffed rate for the particular service on the particular path. Negotiated storage rates (NFS and NAS) will be capped at the price which will provide PG&E the opportunity to recover its total embedded cost revenue requirement for the unbundled storage program for each of the three storage subfunctions (e.g., inventory, injection, or withdrawal).

d. To the extent that PG&E negotiates a transmission contract for its Malin to on–system path with an on–

system end-user, and the negotiated backbone rate component offered is below the analogous Topock to on system path rate, e.g., seasonal firm, PG&E agrees to offer to that end-user [*177] the same negotiated rate for a Topock to on-system path contract, to the extent that capacity is available.

e. Negotiated rates for parking and lending services shall not be less than PG&E's short-run marginal cost of providing the service. These rates will be capped at a daily and/or annual cost to cycle gas using firm storage service.

f. PG&E will issue monthly reports to CPUC covering all negotiated contracts, including those negotiated under NFT, NAA, NFS, and NAS, but excluding PARK and LEND. PG&E will make the report available upon request. Customer names, including PG&E's affiliates and other departments, will not be disclosed in the report. However, the report will indicate whether a particular transaction was with an affiliate. The report will show the negotiated contract rates.

g. The CPUC's complaint procedure will be available to address any undue discrimination claims.

h. PG&E may also offer other customer-specific negotiated contracts. Negotiated transmission and storage service contracts under NFT, NAA, NFS, and NAS will not require submission to the CPUC for approval; however, any other negotiated transmission or storage service contracts will require submission [*178] to the CPUC for approval.

16. Affiliate and Intracompany Transactions

a. PG&E will treat PG&E's affiliates and core procurement and UEG departments without undue preference or undue discrimination.

b. PG&E will not disclose specific shipper information to PG&E's affiliates or core procurement and UEG departments without that shipper's permission, except as needed to serve the shipper.

c. PG&E will provide nonpublic information about the intrastate transmission system to all entities, including PG&E's affiliates and core procurement and UEG departments, without undue preference or undue discrimination.

d. PG&E will develop specific standards of conduct for affiliate transactions to be included in its Accord tariffs.

F. Special Agreements

1. Firm Expansion Agreements

a. As set forth in Section I.B.6, the 304 MMcf/d of Line 401 capacity remains initially dedicated to firm G-XF service, consistent with the Firm Transportation Service Agreements (FTSAs) previously approved by the CPUC for service to the firm Expansion shippers. The G-XF rate will continue to apply to this capacity and to service provided to these shippers for the remainder of the 30-year term [*179] of these agreements, as set forth in part (b.ii), below, except that each shipper may elect one of the options set forth in parts (b.i) and (c), below, and, by virtue of that election, alter the rate, term, and terms and conditions of service. The other 509 MMcf/d of Line 401 firm capacity is redesignated as firm capacity available for subscription under the new transmission services described in Section II.A.

b. Options for Service: Firm Expansion shippers may elect one of the following options for restructuring their contractual commitments. The shippers may elect either of the following two options at any time up to 45 calendar days following CPUC approval of this Settlement Agreement.

i. Accord Service: A shipper may convert its firm Expansion contract to Firm Annual Off–System service (AFT–Off) under the Accord for Malin to off–system service. The rate, terms and conditions of this service are delineated in Section II.A.4. These include a Line 401 capital cost of $736 million, and an on–system delivery option if the shipper elects SFV rate design. Features specially applicable to converting Expansion shippers are the following:
. the term of the replacement [*180] contract is the full remainder of the shipper's 30–year term under its FTSA;
. UTS and all other Expansion–related contact and tariff rights must be irrevocably waived;
. the contract for new service is pro forma (no negotiated agreements) and service is henceforth provided under AFT–Off and superseding tariff(s);
. the shipper's capacity is redesignated as non–Expansion capacity, as discussed in Section I.B.6; and
. PG&E will offer consideration as payment for the shipper's waiver of UTS rights.

ii. G–XF Firm Service: Those firm Expansion shippers that do not elect one of the other options set forth herein will continue to receive service under G–XF, as described below:
. Rates are based on a $736 million capital cost, using PG&E's proposed cost of capital and utility capital structure;
. Rates remain incremental and are based on the operating expenses and cost allocation methodologies proposed by PG&E in its PEPR Application;
. The G–XF firm service continues to apply, but is modified to reflect the revenue requirement assumptions above, and the backbone credit and crossover ban are eliminated;
. UTS and all other contract rights remain applicable only to firm G–XF service; [*181] and
. Delivery points are as set forth in Exhibit A to each shipper's FTSA.

c. Other Options: PG&E is also offering the following three options to Firm Expansion shippers. The following descriptions set forth PG&E's vision of these options, but each option will be negotiated with any interested shipper, and specific terms and conditions may vary as a result of those negotiations. The shippers may elect one of these options by executing the appropriate agreement with PG&E on or before the earlier of (1) December 1, 1996, or (2) the date the CPUC approves this Accord Settlement Agreement.

i. Negotiated Contract Amendments: A shipper may elect either a discounted rate (to be negotiated with PG&E), which is fixed for the term of the **Gas Accord,** or a market index rate, which would fluctuate during the term of the **Gas Accord** within a negotiated floor and ceiling based on differentials between Southwest and Canadian prices. Service under either rate option, once agreed to, will be provided under G–XF, as modified by the **Gas Accord.** At the end of the **Gas Accord** term, and for the remainder of the shipper's 30–year contract term, rates will be set based on a Line 401 capital [*182] cost of $736 million. Beginning on the date the contract amendment is executed, the shipper must waive its UTS provision for the remainder of its 30–year contract term.

ii. Contract buyout: A shipper may terminate its contract obligations either by making a single payment to PG&E or accelerating payment of demand charges by means of a higher negotiated rate for a specified negotiated term. In either case, PG&E intends that the payment shall be of a sum less than the full NPV of the remainder of the shipper's 30–year contract term. Upon payment of the full negotiated buyout amount, the shipper's contract with PG&E for Expansion transportation service, and all rights and obligations under that contract, shall terminate, and the capacity released thereby shall be redesignated as non–Expansion capacity and shall become part of the pool of capacity used to provide Accord transmission services. If a shipper elects the accelerated payment option, service for the term of such payment will be provided under G–XF, as modified by the **Gas Accord,** and the shipper must waive its UTS provision immediately.

iii. Equity Purchase: A shipper may convert its firm service to an equity interest [*183] in Line 401 at a purchase price to be negotiated with PG&E. Under this option, the shipper would purchase a share of Line 401 at least equal to the firm Maximum Daily Quantity (MDQ) set forth in Exhibit A to the shipper's FTSA.

2. EAD Contracts

The EAD contracts provide the equivalent of contract rights as firm transportation service (AFT) on the Topock to on–system path, but at the contract volumetric rate. The EAD customers will have the option of continuing to receive the same bundled transportation service, or taking service under a **Gas Accord** contract. Service under **Gas Accord** contracts will contribute to any use–or–pay obligations under the EAD contract. Because of the unique terms and conditions in the various EAD contracts, individual discussions are needed as to how specific contract provisions will be implemented in the **Gas Accord** contract environment.

3. EOR Contracts

In Decisions 85–12–102 and 87–05–046, the Commission established a long–term transportation program and set the criteria for Enhanced Oil Recovery (EOR) contracts. Existing EOR contracts will be treated based on the Commission's decisions during the Accord period, or until the expiration date of [*184] such contracts, whichever is earlier. Future EOR service will be provided based on the terms and conditions of Accord services.

4. EDCD Agreements

In Decision 94–12–061, the Commission established the Expedited Direct Connection Docket (EDCD) for case–by–case approval of direct connection on PG&E's Line 401. PG&E has one EDCD application (A.96–04–007) pending before the Commission and may file additional applications. To the extent these applications are approved before the **Gas Accord** is implemented, the underlying agreements shall continue in effect during the **Gas Accord** until they expire. Otherwise, new services are provided consistent with the Accord services.

5. Other Existing Agreements

a. Negotiated Interruptible Agreements
PG&E has a number of negotiable interruptible transportation agreements with terms that may extend into the Accord period. PG&E will continue to honor the terms and conditions, including the rate, negotiated for the original term of these contracts. Because the underlying tariff (G–ITS) will be eliminated upon Accord implementation, these terms and conditions will be carried out through an NAA contract.

b. Crockett Cogeneration
Crockett cogeneration [*185] has a negotiated contract which provides for transportation service at volumetric rates. PG&E will continue to honor the terms and conditions, including the rate, negotiated for the original term of this contract. If any terms and conditions are unspecified by the existing contract agreement, then the applicable **Gas Accord** tariffs will apply.

6. SMUD

a. Background
Sacramento Municipal Utility District (SMUD), as the largest municipal utility in the state, is in a unique position and the Accord proposes a unique solution to meet its needs. PG&E and SMUD have agreed, subject to completing definitive agreements and obtaining CPUC approval, that PG&E will sell to SMUD a qualified equity interest in Line 300 and Line 401 backbone facilities.

This transaction along with the Interim and Contingent Rate discussed below, would settle SMUD's BCAP Phase II issues. The details of the transaction will be part of a Section 851 filing seeking CPUC approval of the asset sale.

b. Interim and Contingent Rate
Should the above asset transfers not occur before the **Gas Accord** becomes effective, there will be an interim rate, which is also a contingent rate in the event that the Section 851 [*186] filing is not approved as filed. This rate will include a $0.123 per Dth discount (escalated for inflation over time) from the local transmission

charge component of the otherwise applicable tariff rates for gas delivered and received by SMUD or its affiliate to support its electric utility operations. This rate treatment will terminate upon closing of SMUD's purchase of a qualified, equity interest in Lines 300 and 401.

G. General Description of Transmission and Unbundled Storage Program Rates

1. Unbundle transmission and a portion of storage from distribution services.

2. Establish transmission, distribution, and storage rates based on cost of service.

3. Make transmission and storage service available to all entities, including end-users, shippers, producers and marketers.

4. Collect social, environmental, and transition costs and balancing accounts from on-system end-use volumes.

5. Backbone rates associated with service to storage are paid upon injection. For on-system deliveries, the remaining transmission rates are paid upon withdrawal.

6. New Transmission Rates

a. Differentiate transmission rates by path to reflect facilities used to provide service.
[*187]
b. Establish two-part firm rates (reservation and usage charges) and one-part As-available rates (volumetric or usage charges).

c. Establish a customer access charge to cover the costs of meters and service drops, meter reading, billing and payment processing where applicable.

7. Pre-existing Transmission Rates
For those services with pre-existing contracts discussed in Section II.F, charge the rates shown in Section II.B.

8. Storage Rates for the Unbundled Storage Program

a. Establish two-part (reservation and volumetric) rates for both the capacity (injection and inventory) and withdrawal subfunctions for Firm Storage Service.

b. Negotiated storage rates may be based on three subfunctions (inventory, injection, and withdrawal) and may be either one-part or two-part rates.

H. Transmission and Unbundled Storage Program Rates

1. New Transmission Rates

a. Four rate components will be applicable to on-system transmission service. A backbone transmission charge, a local transmission charge, a customer class charge, and a customer access charge. Shippers delivering on-system will be charged the backbone transmission charge, and corresponding end-users will [*188] be charged the local transmission charge, the customer class charge and customer access charge.

b. The backbone transmission charge, the local transmission charge, and the transmission-level customer access charge, will not change from the rate set forth in this Accord, except pursuant to the z-factor.

c. New off-system transmission service under the Accord includes a backbone transmission charge, and a customer access charge where applicable. The backbone transmission and customer access charges are guaranteed except for the z–factor.

d. Backbone Transmission Charge

i. The backbone transmission charge is designed to collect backbone transmission revenues and is applicable to all transmission customers.

ii. The retail core market receives 600 MMcf/d (609 Mdth/d) and the core wholesale market receives up to 6.5 MMcf/d (6.6 Mdth/d) of Malin to on–system firm intrastate capacity at vintaged rates.

iii. The Malin to on–system rate is based on an intrastate capacity phase–in, over the period from 1997 through 2002 of 375 MMcf/d (381 Mdth/d) of Line 401 and the portion of Line 400 embedded costs not allocated to the retail core and core wholesale.

e. The local transmission [*189] charge collects local transmission costs and is applicable to all on–system end–users.

f. The customer class charge includes social, environmental and transition costs, balancing account balances and all other non–base revenue requirements. Some of the costs included in this charge are CARE, CEE programs, hazardous substance, and ITCS costs. It is generally applicable to all on–system end–users.

g. The customer access charge includes the cost of meters and service drops, meter reading, billing and payment processing, and is applicable to the customers to whom PG&E provides these services (see Section II.I.10).

h. Transmission rates for AFT, SFT, and AA are shown in Section VI.

2. Pre–existing Transmission Rates

Pre–existing services and contracts are discussed in Sections II.B and II.F.

3. Storage Rates for the Unbundled Storage Program

a. Rates for storage services are based on the costs of storage injection, inventory and withdrawal.

b. Firm Storage

i. Rates are subfunctionalized by a capacity (combined injection and inventory) charge and withdrawal charge.

ii. Capacity and withdrawal charges are recovered through a reservation (fixed) and volumetric (variable) [*190] component.

c. Negotiated Firm and As–available services are negotiable above a price floor representing PG&E's short–run marginal cost of providing the service.

d. Negotiated Firm rates can be recovered through a volumetric–only charge or a reservation and volumetric charge.

e. Negotiated As–available Storage Injection and Withdrawal rates are recovered through a volumetric charge only.

f. Negotiated storage rates (NFS and NAS) are capped at the price which will collect 100 percent of PG&E's total embedded cost revenue requirement for the unbundled storage program for each of the three storage subfunctions (e.g., inventory, injection, or withdrawal). The flexibility inherent in this storage offer could result in stranded facilities and PG&E requires the opportunity to collect the value of its storage services.

g. Firm storage rates for the unbundled storage program are shown in Section VI.

I. Cost Basis and Rate Design

1. The Backbone Component of New Transmission Path Rates

a. Except for certain services and contracts described in Section II.F, all on-system rates include a backbone transmission component that varies by path, and a common backbone component. [*191] The common backbone component includes the costs of backbone facilities used by all on-system paths, and gathering mains.

b. The incremental Line 401 costs used in developing the Malin to on-and off-system rates are based on the Pipeline Expansion assumptions shown in Section II.I.3. Off-system rates do not include any common backbone component.

c. Malin to on-system rates for the core (including core wholesale) are based on a prorated portion of vintaged Line 400 and Line 2, and the common backbone component.

d. Malin to on-system rates for all customers except retail core and core wholesale include the cost of the portions of Line 400 and Line 2 not reserved for the core, the common backbone component, and a phased-in portion of Line 401 costs as described in Section II.I.3.

e. Both the Topock to on-system and the Topock to off-system rates include the cost of Line 300 and the common backbone component. Capital costs of $42 million for NOx-related retrofits needed to meet NOx emission standards are included in the Line 300 revenue requirement. To the extent PG&E's expenditures exceed the $42 million, PG&E will be at risk for recovery of these expenditures during the **Gas** [*192] **Accord** period, but does not waive the right to seek recovery after that.

f. California production to on-system rates include 40 percent of the average backbone transmission costs and the common backbone component. California production to off-system rates assume Line 401 will be used, and the rate is equal to the Line 401 to off-system rate.

g. The on-system and off-system rates are guaranteed for the Accord period, subject to change pursuant only to the z-factor provision of Section II.I.7.

2. The Storage Costs in the Unbundled Storage Program

a. The storage costs allocated to the unbundled storage program represent 12.5 percent of the inventory, injection, and withdrawal storage costs remaining after the allocation for load balancing requirements.

b. The maximum rates for Negotiated Firm Storage and Negotiated As-available Storage are based on a rate design assuming an average injection period of 30 days and an average withdrawal period of seven days. The rates assume full collection of the total unbundled storage program revenue requirement in each individual subfunction.

c. The minimum rates for Negotiated Firm Storage and Negotiated As-available Storage are based [*193] on the marginal price floor to provide the service.

3. Revenue Requirement Assumptions

a. Gas Department (excluding Pipeline Expansion)

i. Initial base revenue requirements for calculating 1997 rates match PG&E's 1996 GRC.

ii. Cost of capital and capital structure are based on the 1996 Cost of Capital proceeding's authorized cost of capital for the gas department.

iii. Gas department common costs are allocated to backbone transmission, local transmission and distribution based on plant and labor.

b. Development of the Line 401 Revenue Requirement

i. Base revenue requirements are calculated using the proposed litigation resolution figure of $736 million of capital costs discussed in Section V. Operating expenses and the methods used to allocate costs and calculate taxes and the revenue requirement match PG&E's current position in the Pipeline Expansion Project Reasonableness (PEPR) Case.

ii. Cost of capital and capital structure matches PG&E's gas department cost of capital as authorized in the 1996 Cost of Capital Decision 95-11-062, with no premium on the return on equity.

iii. No common costs, except those included in the PEPR Case, are included. [*194] The cost allocation methods match those used in the PEPR Case. The allocation of original facilities to the Expansion increases to the amount proposed by PG&E in the PEPR Case.

c. Line 401 Cost Phase-in to On-system Rates

Each year a portion of the Line 401 revenue requirement will be included in the Malin to on-system rate. The portion is calculated using the firm Expansion capacity of 813 MMcf/d (825 Mdth/d). The Line 401 revenue requirement phased-in each year will be based on depreciated plant. The following table summarizes the amount of capacity used to determine the phased-in costs:

Capacity	1997	1998	1999	2000	2001	2002
Incremental (MMcf/d)	200	50	50	25	25	25
Cumulative (MMcf/d)	200	250	300	325	350	375
Cumulative (Mdth/d)	208	254	305	330	355	381

4. Load Factor and Rate Cap Assumptions

a. Firm annual on-system backbone transmission charges are based on an annual average capacity factor of 87.5 percent. Malin to on-system capacity increases each year consistent with the cost phase-in. Seasonal firm and As-available rates are set at 120 percent of the annual firm rates. As-available rates are set at 110 percent of the annual [*195] firm rates through March 31, 1998, and at 120 percent thereafter. The load factors used in setting backbone transmission rates remain constant through the **Gas Accord** period. The core's Topock to On-system path charge for firm seasonal capacity will be calculated at 110 percent of the firm annual price for the period through March 1998.

b. The Malin to off-system firm rates are calculated using incremental Line 401 costs and a 95 percent load factor. The Malin to off-system As-available rates are set at 110 percent of firm rates through March 31, 1998, and at 120 percent thereafter.

c. On-system California production and storage to off-system rates are equal to the Malin to off-system rates.

5. Balancing Account Treatment

a. There will be no balancing account treatment for backbone or local transmission revenues, or for parking or lending service revenues.

b. The current storage program has a contractual operating period from April 1 through March 31. Therefore, PG&E will not offer firm storage service until April 1, 1998, and PG&E will continue to honor storage contracts for the 1997/1998 storage season. PG&E may begin offering as-available storage service upon implementation [*196] of all other services if capacity is available. Balancing account treatment for the current storage program will continue through March 31, 1998. Any outstanding balance plus interest will be allocated to core and noncore customers on an equal cents per therm basis. PG&E will absorb 100 percent of the core share.

6. Shrinkage (compressor fuel, and lost and unaccounted for gas)

In-kind shrinkage will be charged to all gas shipped on the PG&E transmission system on a postage-stamp basis. Additional shrinkage will be charged for distribution service, also on a postage-stamp basis. The Malin to off-system shrinkage rate is the rate adopted in Decision 94-02-042. The shrinkage rate for all other transmission paths is developed using rates authorized in PG&E's BCAP Decision 95-12-053 and is subject to change in subsequent BCAPs. Transmission shrinkage will be charged for all deliveries into storage, but not for deliveries out of storage.

Path	Shrinkage Rate
Malin to Off-system	1.11%
All Other Transmission Paths	1.72%

7. Rate Adjustments

a. The Line 400 component of Malin rates escalates at 2.5 percent annually.

b. Line 401 costs used to establish the phase-in component [*197] of the Malin to on-system rates and the Malin to off-system rates are adjusted in accordance with PG&E's Pipeline Expansion Rate Case methodology and the litigation resolution agreement in Section V.

c. Line 300 rates escalate at 2.5 percent annually, plus the revenue requirement associated with the $42 million of capital cost additions for NOx-related retrofits needed to meet NOx emission standards.

d. Storage and parking and lending rates escalate at 2.5 percent annually.

e. The guaranteed rates may be adjusted by a z-factor to reflect extraordinary costs or savings. The z-factor is limited to known changes due to governmental action. An example of a government action would include changes to the federal or state income tax rate. The z-factor mechanism would not replace either the current CEMA or the Hazardous Substance incentive mechanism, both of which would remain in effect.

f. The following z-factor sharing mechanism (costs or savings) is adopted for cost responsibility per each extraordinary event:

z-Factor Cost (Savings) Per Event	Cost Responsibility
$ 0- $ 5 million	100% PG&E
> $ 5 - $ 10 million	50/50 sharing

z-Factor Cost (Savings) Per Event	Cost Responsibility
> $ 10 million	100% customers

8. [*198] Local Transmission Charge

a. The charge includes the cost of local transmission facilities.

b. The local transmission charge is paid by all on-system end-users. This charge is non-bypassable.

c. The local transmission charge varies by core and noncore customer class. Local transmission costs are allocated to core and noncore based on LRMC methodology from PG&E's BCAP Decision 95-12-053.

d. Local transmission rates escalate at 2.5 percent annually.

e. The local transmission charge will have no balancing account protection.

f. The rates are guaranteed for the Accord period, subject only to the z-factor provisions of Section II.I.7.

g. Local transmission rates are shown in Section VI.

9. Customer Class Charge

a. The customer class charge is designed to collect social, environmental and transition costs, balancing account balances, and all other non-base revenue requirements. Some of the costs included in this charge are CARE, CEE programs, hazardous substance, and ITCS costs.

b. The core customer class charge does not include ITCS. PG&E will absorb all of the core portion of the ITCS charges as defined herein, less brokering revenues, plus interest, from the [*199] beginning of the ITCS account, as part of the litigation resolution described in Section V. The customer class charge includes a "true-up" of ITCS costs collected from core customers prior to Accord implementation.

c. The noncore customer class charge includes only 50 percent of the noncore ITCS costs, less brokering revenues, plus interest, from the beginning of the ITCS account. PG&E will absorb the remaining 50 percent of the noncore ITCS costs, as part of the litigation resolution described in Section V.

d. The customer class charge does not include any component for recovery of the backbone credit. PG&E will absorb 100 percent of the Backbone Credit Account. PG&E will not provide any shipper with a backbone credit after the **Gas Accord** is approved, as part of the litigation resolution described in Section V.

e. Initial customer class charges have been allocated to customer classes and will be collected in rates as determined in PG&E's 1996 GRC and PG&E's BCAP Decision 95-12-053. These charges will be periodically adjusted based on the regulatory proceedings associated with each account and continue to be subject to balancing account treatment.

f. PG&E will collect the [*200] existing balance in the Noncore Fixed Cost Account (NFCA), but will not record any activity to the account other than amortization revenue and interest after implementation of the **Gas Accord.**

g. Customer class charges will be paid by on-system end-users only. However, loads subject to Line 401 direct connect agreements or EOR contracts will neither pay, nor be allocated, customer class charges while the direct connect agreements or contracts are in effect.

h. Forecast customer class charges are shown in Section VI.

10. Customer Access Charge

a. End-users who are directly connected to the transmission system will pay a customer access charge each month. The purpose of the customer access charge is to assess the end-user a fee for the cost of providing and maintaining the individual end-user's service connection to the transmission system.

b. For industrial end-users, the customer access charges will be the same as the current industrial customer charge. With the current industrial customer charge, each end-user is placed in one of six tiers depending on the end-user's specific annual volumetric usage. There is a specific monthly charge associated with each tier. Distribution [*201] industrial customers will have the same initial customer access charge as part of their distribution rates.

c. The UEG and cogenerator customer access charges will be based on the annual scaled marginal customer cost revenues adopted in BCAP Decision 95-12-053. For UEG, the customer access charge is a monthly charge. For cogeneration end-users, the customer access charge will be a volumetric adder, calculated such that the UEG-cogeneration rate parity is maintained. For cogeneration end-users currently on Schedule G-CGS, the volumetric adder will equal UEG customer access charges for twelve months divided by the UEG average annual forecasted throughput adopted in BCAP Decision 95-12-053. For cogeneration end-users currently on Schedule G-EPO, the volumetric adder will equal the UEG monthly customer charge divided by UEG actual monthly throughput, lagged by sixty days.

d. For wholesale customers, the customer access charge for each month of 1997 will equal the scaled annual marginal customer cost revenues adopted in BCAP Decision 95-12-053 for each specific wholesale customer divided by twelve.

e. Customer access charges escalate at 2.5 percent per year annually.

f. Current [*202] customer access charges are shown in Section VI.

g. Customer access charges for transmission level customers are guaranteed for the Accord period, subject only to z-factor changes described in Section II.I.7.

11. Cogeneration Rate Parity

a. On-system cogeneration tariff transmission rates will be available to all cogenerators, including EPO3 cogenerators, from PG&E's transmission department. For each path and service, cogenerator rates will be set equal to the average Utility Electric Generation (UEG) rate for that path and service. UEG negotiated rates received from PG&E's transmission department will be included in the rate calculations on a weighted average, n1 path specific, service specific n2 basis. PG&E will develop, in cooperation with cogenerators, a mechanism to incorporate UEG negotiated rates into cogeneration rates.

b. In the event that the current methodology used to determine payments to EPO3 cogenerators changes so that it is no longer based on actual UEG natural gas costs, PG&E will negotiate with EPO3 customers in good faith to develop a method for calculating EPO3 natural gas transmission service rates which maintains the linkage between EPO3 cogenerators' [*203] transmission rates and their electricity payments. Such resulting rates would be subject to CPUC approval and will apply only until the expiration of the EPO3 payment option.

c. Transportation services provided to the UEG by entities other than PG&E's transmission department will not be included in the cogeneration rate calculations. The UEG includes only PG&E-owned utility fossil-fired generation facilities. If the UEG does not take any service from PG&E's transmission department on a particular path for a particular service, the on-system cogeneration tariff rates for that path and service will equal the otherwise-applicable cogeneration tariff rates for that path and service.

d. On-system cogeneration transmission rates will be available only to cogeneration end-users for their own usage up to the authorized cogenerator gas allowance. n3 If the cogeneration rate parity statute (Public Utilities Code Section 454.4) is amended or repealed so that "rate parity" is no longer required by statute, n4 and if the CPUC for whatever reason no longer requires such rate parity, then there will be no separate transmission tariff rates applicable to cogeneration end-users. For purposes of [*204] this paragraph, PG&E shall be free at any time (following the amendment or repeal of the cogeneration rate parity statute so that "rate parity" is no longer required by statute) to file a superseding tariff for cogenerators with the CPUC, which filing may be the occasion for the CPUC to reevaluate the requirement for such rate parity. Cogenerators expressly retain the right to oppose such a filing by PG&E. n5

e. An on-system cogenerator's monthly bill for non-discounted tariff service provided by PG&E's transmission department shall be the minimum of the bill calculated using the transmission rates described above, and the bill calculated using the otherwise-applicable tariff transmission rates for that path and service.

f. During open seasons for intrastate transmission capacity, PG&E will notify on-system cogenerators of UEG's elections for service from PG&E's transmission department three business days prior to the date that cogenerators must make their service elections. PG&E will also notify on-system cogenerators of UEG's other elections for service from PG&E's transmission department as they may occur from time to time. This will apply only to UEG service agreements whose [*205] durations are more than 30 days.

n1 That is, the firm service rate for cogenerators will be calculated using any negotiated rates for firm service for UEG weighted by volume; similarly, the As-available service rate for cogenerators will be calculated using any negotiated rates for As-available service for UEG weighted by volume.
n2 For purposes of this paragraph, the term "service specific" shall refer to either firm service or As-available service (including negotiable rate, non-negotiable rate and other variations of such service) and indicates the distinction between firm and As-available as separate services.
n3 The cogenerator gas allowance is not to be determined by the **Gas Accord,** except that it will remain within 10 percent of 0.09683 th/kWh.
n4 The **Gas Accord** does not restrict either PG&E or cogenerators from seeking legislative changes to P.U. Code Section 454.4, but the parties shall support the provisions of the **Gas Accord** before the CPUC.
n5 The provisions of this section are not intended to limit parties' abilities to address before the CPUC any issue they think appropriate dealing with the divestiture of PG&E generation units. This could include discussion of any cogeneration rate parity topics as they might relate in any way to divested units.

[*206]
III.DISTRIBUTION SERVICESA. Services for Noncore End-users

1. Distribution transportation service: Noncore customers connected to PG&E's distribution system may arrange for transmission, storage, and supply services separately. These customers receive noncore distribution service from PG&E.

2. Core subscription: Noncore customers may have PG&E arrange for their supply and transmission service under core subscription service, described in Section IV.M.

3. Residual load service: PG&E will propose a residual load service in the next BCAP.

B. Service for Core End-users

1. PG&E will continue to provide bundled service for core end-users. See Section IV for changes that may affect core service.

2. PG&E will also provide core transport service for core end-users. See Section IV for a discussion of core aggregation.

C. Rates and Cost Allocation

1. Distribution Revenue Requirement Assumptions

a. The initial natural gas distribution revenue requirement will match PG&E's 1996 GRC Decision 95-12-055, consistent with the transfer of DFMs to local transmission. Customer access charges for transmission-level end-users have been moved from the distribution [*207] revenue requirement to the customer access charge.

b. The distribution revenue requirement in future years of the **Gas Accord** will be based on cost of service or Performance Based Regulation (PBR), whichever is applicable. For the purposes of calculating the illustrative rates shown in Table 16 in Section VI, the revenue requirement escalates at 2.5 percent per year.

2. Distribution Cost Allocation

a. The initial distribution revenue requirement will be allocated to end-users on an Equal Percent of Marginal Cost (EPMC) basis, using distribution and customer marginal cost revenues consistent with PG&E's BCAP Decision 95-12-053.

b. PG&E will continue to have BCAPs and GRCs or successor proceedings to update the allocations of costs. The methodology for allocating the distribution revenue requirement between core and noncore will not be changed for the term of the **Gas Accord,** although the allocation itself may change due to, among other things, changes to throughput forecasts or marginal costs. The allocation of revenues within the core will be addressed in future BCAPs.

3. Distribution Throughput

a. Distribution throughput for noncore end-users has been modified to [*208] reflect loads served directly from the transmission system, as well as end-users connected to the distribution system but classified as transmission customers.

b. Core and noncore throughput forecasts will be addressed in future BCAPs or PBRs.

4. Balancing Account Treatment

a. PG&E's core procurement department's cost of intrastate backbone and local transmission service for the core will receive 100 percent balancing account treatment for the costs incurred, either through the Core Fixed Cost Account, (CFCA) or the Purchased Gas Account (PGA).

b. The core distribution revenue requirement will continue to receive 100 percent balancing account treatment.

c. Balancing account treatment (Noncore Fixed Cost Account) for prospective noncore distribution revenues will be eliminated.

5. Shrinkage

a. Noncore customers and core transport customers will continue to deliver in-kind shrinkage. Bundled core end-users and core subscription customers will continue to pay shrinkage as part of their procurement rate.

b. Shrinkage will be charged on the distribution system on a postage-stamp basis for all gas deliveries. Distribution shrinkage is in addition to any shrinkage [*209] applied on the transmission system.

c. Distribution shrinkage is calculated using percentages authorized in PG&E's most recent BCAP Decision 95-12-053, as follows: the core distribution shrinkage rate (including core transport) is 3.31 percent, and the noncore distribution shrinkage rate is 0.21 percent. These percentages are subject to change in future BCAPs. The core shrinkage subaccount will continue as currently authorized.

6. Distribution Rates and Rate Design

a. Forecast distribution rates and illustrative intrastate bundled core transportation rates are shown in Section VI.

b. The initial core commercial winter distribution rate component will remain at 135 percent of the summer distribution rate component. For core commercial customers taking bundled service from PG&E, intrastate transmission costs will be allocated into the season in which they are incurred, and storage costs will be included in winter season rates only. Commodity costs will not be included in any seasonal rate differential calculation.

c. The initial noncore winter distribution rate component will be 135 percent of the summer distribution rate component.

d. Future distribution rate design, [*210] rates, residential tier differentials, and core deaveraging, among other things, will be determined in future BCAPs. Parties also reserve the right to propose other cost-based core cost allocation and rate design changes in future BCAPs.

7. Cogeneration Rate Parity

a. Consistent with the CPUC's cogeneration rate parity policy, distribution level cogenerators will not have a distribution component in their rate. The resulting "cogeneration shortfall" will be a part of the customer class charge, and will be collected from cogeneration and UEG end-users, for their own usage up to the authorized cogenerator gas allowance.

b. If the cogeneration rate parity statute is amended or repealed so that "rate parity" is no longer required by statute, and if the CPUC for whatever reason no longer requires such rate parity, then distribution level cogenerators will be served under the otherwise applicable distribution rate, and there will be no separate cogeneration class.

c. PG&E shall be free at any time (following the amendment or repeal of the cogeneration rate parity statute so that "rate parity" is no longer required by statute) to file a superseding tariff for cogenerators with [*211] the CPUC, which filing may be the occasion for the CPUC to reevaluate the requirement for such rate parity. Cogenerators expressly retain the right to oppose such a filing by PG&E.

8. Discounting

a. Distribution service may be discounted to prevent uneconomic bypass of PG&E's distribution system and to encourage business retention and business attraction.

b. PG&E may negotiate discounts with distribution-level noncore end-users to prevent uneconomic bypass of PG&E's distribution and transmission systems, and to encourage business retention and business attraction.

c. Any negotiated discounts with core end-users for distribution service will require CPUC approval prior to going into effect.

d. If the purpose of a noncore discount negotiation is to attract or retain both transmission and distribution load, any discount will be "split" between transmission and distribution services proportional to the revenue to each system at full tariff prices. The noncore end–use customer would receive the transmission portion of the discount in a bill credit, or through local transmission or customer access charges.

e. If a negotiated distribution service benefits only the distribution [*212] system, any discount will be reflected only in distribution rates.

f. PG&E will have the option in BCAP proceedings of demonstrating the reasonableness of any discounted distribution contracts that will continue into the prospective period. If the Commission finds the discounts to be reasonable, PG&E will be allowed to recover the forecasted revenue shortfalls during the prospective period.

g. Negotiated contracts and affiliate transactions rules which will apply to transmission services will also apply to distribution services. (See Sections II.E.15 and II.E.16.)

IV. PG&E'S FUTURE ROLE IN CORE PROCUREMENTA. Overview

PG&E proposes to reduce costs to customers and to expand core customer choices by:

1. Encouraging greater customer choice among gas suppliers;

2. Reducing PG&E's regulated sales of gas to core customers;

3. Reducing PG&E's interstate pipeline capacity holdings for the core;

4. Establishing operational principles that provide market flexibility while ensuring safe and reliable service;

5. Implementing appropriate incentive mechanisms; and

6. Negotiating with California producers for a mutual release of PG&E's gas purchase contracts and [*213] reducing gas gathering costs through the disposal of assets.

B. Core Procurement Advisory Group

1. Significantly reducing PG&E's role in the core procurement market requires significant expansion of the current core gas transportation program. This program now serves only about three percent of the core load in PG&E's service area, and well under one percent of core customers.

2. To determine the changes that should be made to the program, PG&E invited all **Gas Accord** parties to participate in the Core Procurement Advisory Group (CPAG). The focus of the CPAG was the development of recommendations that would accomplish two primary objectives:

a. Make the program consistent with the proposed **Gas Accord** framework; and

b. Remove barriers, from both the customers' and aggregators' perspectives, to increasing program participation.

3. Approximately 50 parties joined PG&E and identified over 40 separate issues that needed to be resolved. Two working groups were established to conduct the detailed negotiations necessary to resolve these issues and balance the widely diverse interests of the parties.

4. After the initial package of recommendations was developed, three [*214] new CPAG working groups

were established to facilitate implementation of the CPAG recommendations:

a. Market Test: The Market Test work group will participate in the development and performance of market research and affinity-group marketing field tests that are required to enhance core aggregation in PG&E's service area.

b. Tariff Revisions: The Tariff Revision work group will assist as PG&E's tariffs are revised to incorporate the CPAG recommendations that are ultimately approved in the **Gas Accord** proceeding.

c. Load Forecast and Determination Model: The Load Forecast and Determination Model work group will participate in the development of a model that will be used for core load balancing purposes.

5. The agreements below reflect the approved package of CPAG recommendations. The core aggregation agreements are intended to apply to PG&E's service area. They are not intended to set precedents for any other utility service area, or for noncore service. Additional information about the detail behind these proposals can be found in the CPAG agreement.

C. PG&E's And Aggregators' Roles In The Changing Core Gas Sales Market

1. As part of its compliance [*215] filing following approval of the **Gas Accord,** PG&E will file tariffs to lift the ten percent cap on PG&E's core gas aggregation program.

2. Aggregators have the obligation to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

3. PG&E has the obligation to operate the gas system safely and efficiently and to purchase gas supplies for customers not served by aggregators.

4. PG&E's remaining core gas procurement role will be as a regulated utility supplier within PG&E's service area during the **Gas Accord** period.

5. The CPAG will explore, through market research efforts, several ways to attract small and highly seasonal customers to core transportation service and to reduce transaction costs for aggregators to serve them.

6. PG&E and the aggregators will each be responsible for dealing with their own customers' payment problems. The allocation of costs to serve slow-and non-paying customers will be reexamined when PG&E's core gas sales market share drops to 80 percent.

7. The costs of social and environmental programs such as CARE, clean air vehicles and customer energy efficiency will continue to be recovered from all on-system [*216] end-users through the customer class charge component of the transportation rates.

8. CARE core transportation customers will receive the CARE benefits regardless of their choice of gas supplier.

D. Reducing PG&E's Interstate Pipeline Capacity

PG&E will adjust its core capacity holdings of firm interstate pipeline capacity as follows:

1. PG&E's contract with El Paso will terminate at the end of 1997. As part of the current El Paso general rate case (FERC Docket Nos. RP95-363-000, et al.), PG&E's termination of this contract, as well as other utility contract step-downs and the related costs, are addressed in a settlement filed with the FERC on March 15, 1996. The parties agree that any costs paid by PG&E resulting from the FERC-approved settlement will be treated as one component of the overall interstate pipeline reservation charges; and therefore, will be

allocated to core and noncore customers using the allocation methodology for interstate pipeline reservation charges adopted in PG&E's BCAP Decision 95–12–053.

2. PG&E reserves the right to subscribe to additional interstate capacity in the future, with costs assigned to PG&E's core procurement customers.

3. Other [*217] reductions may be made by PG&E (as allowed by PG&E's interstate capacity contracts) as core aggregators' share of the core market increases.

E. PG&E's Core Procurement Department Intrastate Pipeline And Storage Capacity

1. PG&E's core procurement department will hold intrastate transportation capacity on behalf of its core and core subscription customers. The following initial firm reservation of intrastate transportation capacity will be made for the retail core:

a. PG&E's retail core initially will be allocated the following quantities of firm transmission capacity:

		Malin to On–system	Topock to On–system	California
Annual	MMcf/d	600	150	50
	Mdth/d	609	155	48

b. PG&E's retail core will also hold additional seasonal winter capacity as follows:

		Malin to On–system	Topock to On–system	California
November and March				
	MMcf/d	0	150	0
	Mdth/d	0	155	0
December to February				
	MMcf/d	0	450	0
	Mdth/d	0	464	0

2. The initial firm allocation of Malin capacity for the retail core will be priced at vintaged rates.

3. PG&E's core procurement department will continue to be allocated firm rights to a portion of storage [*218] capacity on behalf of the core market, as specified in Section II.E.5. The core's storage and other costs related to maintaining the safe and reliable operation of the gas system will be included in core rates.

F. Core Aggregators' Holdings Of Interstate Capacity

1. PG&E will make two filings to unbundle interstate transmission costs from core transport rates within 30 days after a comprehensive **Gas Accord** agreement is signed.

a. The first filing will address unbundling prior to January 1, 1998. This filing will:

i. unbundle PGT and El Paso capacity;

ii. impose a surcharge on core transport rates until January 1, 1998, not to exceed $0.19/Dth, to cover any resulting transition costs;

iii. continue the present treatment of ANG and NOVA costs; and

iv. implement the rate credit described in Section IV.G.6.

b. The second filing will address unbundling after January 1, 1998, when PG&E's El Paso contract will expire. This filing will:

i. continue unbundling of PGT capacity; and

ii. provide that, once the core transport share of PGT core capacity exceeds the point where PG&E's remaining PGT core capacity matches its upstream rights on ANG and NOVA, approximately [*219] 40 MMcf/d, core aggregators taking a share of PGT core capacity will have the right, but not the obligation, to accept a proportionate share of ANG and NOVA capacity, to the extent it is available, for additional PGT capacity reservations.

iii. provide that, to the extent that core aggregators taking a share of PGT core capacity choose not to take a proportionate share of ANG and NOVA capacity, PG&E will have the right to offer to assign the capacity to other shippers for one month up to the duration of PG&E's contracts with ANG and NOVA. This may result in core aggregator's not having access to this capacity in the future. If PG&E chooses not to make such an offer, or is not successful in finding shippers for the full amount offered, PG&E will broker the capacity.

iv. provide that, 50 percent of the difference between the cost of PG&E's contractual obligations for the proportionate share of ANG and NOVA capacity offered to, but not taken, by core aggregators, and the revenues collected by PG&E as a result of brokering efforts for that capacity will be allocated to the transportation rates paid by PG&E's core transport customers. PG&E's shareholders will be at risk for the remaining [*220] 50 percent.

2. Core aggregators will choose their own interstate pipeline capacity mix. Each month, core aggregators will have a preferential right (but not the obligation) to acquire a portion of PG&E's interstate capacity holdings to serve their core customers.

3. If core aggregators choose not to acquire PG&E's firm capacity rights, or if this capacity is marketed at less than as-billed rates, unrecovered pipeline reservation fees will become a transition cost, subject to the $0.19/Dth cap in Section IV.F.1.a.ii above until January 1, 1998.

4. Beginning January 1, 1998, any pipeline transition costs resulting from existing PGT commitments on behalf of core transport customers will be allocated to all core customers for the term of the **Gas Accord.** This provision will be reexamined if transition costs exceed $5 million per year.**G. Core Aggregators' Holdings Of Intrastate Capacity and Storage**

1. Intrastate transmission costs will be unbundled from core aggregation customers' rates effective with the Accord.

2. For the initial two years of the **Gas Accord,** aggregators must hold firm intrastate transmission capacity rights during the winter season equal to a proportional [*221] share of PG&E's initial core reservation during the five winter months, excluding the California on-system reservation. Thereafter, aggregators who perform reliably will have no firm requirements.

3. Aggregators may choose the transmission path of their reservation. They are entitled, though not obligated, to subscribe to a proportional share of the vintage-priced Malin to on-system core reservation and/or a proportional share of the Topock to on-system reservation.

4. Aggregators may also use the following alternatives to meet their firm intrastate transmission requirements:

a. Standard agreements to use other firm holders' rights when needed;

b. California gas supplies; or

c. Firm storage capacity in addition to their assigned capacity, if available.

5. Aggregators will continue to be assigned a proportional share of PG&E's core storage reservation based on the winter season throughput of the core transport customers (consistent with CPUC Decision 95-07-048), with the obligation to fill it and maintain minimum inventory levels for reliability purposes. However, to the extent possible without compromising the reliability functions of storage for core customers, aggregators [*222] will have the right to use storage balances above each aggregator's minimum level described in PG&E's G-CT tariff to cure imbalances, to make same-day injection and withdrawal nominations, and to sell or trade gas in storage.

6. Within three years after the **Gas Accord** is implemented, PG&E will file with the CPUC an examination of storage unbundling for core transportation customers in light of the then-existing market.

7. In recognition of the fact that aggregators have settled for less service unbundling than they preferred, and to encourage participation in the core transportation program, PG&E's shareholders will fund a $0.095/Dth credit to core transport rates until January 1, 1998.

H. Core Aggregation Regulatory Issues

1. The PG&E core procurement brokerage fee will be set at $0.024/Dth and will be subject to balancing-account recovery. This fee will be reviewed when PG&E's market share drops to 80 percent.

2. In compliance with the provisions of California Public Utilities Code Sections 6350-6354, PG&E will continue to collect city/county franchise fees for service provided by aggregators based on its own weighted-average cost of gas (WACOG). PG&E will seek [*223] legislative changes to allow similar treatment for utility users' taxes.

3. Billing and metering costs will remain bundled. PG&E will install additional metering at the request/expense of aggregators and their customers, and will provide a credit if PG&E equipment can be removed as a result.

4. PG&E will continue to oversee aggregators' creditworthiness, pursuant to PG&E's Gas Rule 23, Gas Aggregation Service for Core Transport Customers.

5. Aggregators will continue to be required to sign a core transport agreement with PG&E. Aggregator-customer contracts are strictly between the parties.

6. Customers must sign a PG&E agreement for service from an aggregator for an initial term of 12 months. PG&E will conduct market research to see if this requirement is a significant barrier to program participation.

7. In order to prevent slamming (unauthorized switching of a customer from one aggregator to another), written consent will continue to be required from customers who want to change their gas aggregators.

8. Aggregators may obtain PG&E customer information required to select and serve their customers (such as balances owed and customer-service details) when authorization [*224] is given by the customer.

9. PG&E will provide aggregators with a list of qualified gas-supply businesses owned by minorities, women, and disabled veterans that may be used when purchasing gas supplies. PG&E will also provide gas-supply businesses owned by minorities, women, and disabled veterans with a list of qualified core aggregators and other information needed to participate in PG&E's core gas transportation program.

10. The minimum size for a core transport group will be lowered from 250,000 therms per year to 120,000 therms per year.

11. After three years, PG&E will file a core transport program status report with the CPUC, and PG&E will hold a workshop to address any difficulties that have arisen with respect to PG&E's core gas transportation program.

12. The modifications for core aggregation are designed so that they do not have a significant adverse impact on PG&E's remaining core procurement customers.

I. Core Aggregation And Customer Information

1. Customers of aggregators may continue to select a consolidated payment option, where aggregators in compliance with PG&E's Gas Rule 23 creditworthiness standards collect and forward to PG&E appropriate transportation [*225] revenues from their customers, as long as the payments to PG&E are on time.

2. PG&E and the aggregators will work together to develop a common Electronic Data Interface (EDI) protocol, which all aggregators will then be required to use, to streamline data and monetary transfers necessary to serve their customers.

3. PG&E will continue to promote the core transportation program to customers through periodic bill inserts and provision of aggregator lists upon customer request. PG&E will also promote the core transportation program to its own employees through an internal education program.

4. PG&E will conduct a market test to see if outreach efforts through affinity groups (e.g., city governments, schools, churches) are effective in increasing program knowledge and participation and reducing aggregators' transaction costs.

5. PG&E call centers will be equipped to handle calls about the core transportation program.

6. PG&E will provide aggregators with a bill insert that they may use to ensure that their customers know to call PG&E for service-or safety-related questions. Aggregators will refer all such calls that they receive from their customers to PG&E.

J. Customer [*226] **Aggregation Service and Operational Issues**

1. PG&E will provide aggregators with a new Core Load Forecasting and Determination Service. This service will feature 24-and 48-hour forecasts and day-after estimated ("determined") use, based on each aggregator's customer mix.

2. The sum of the daily determined use figures will be used to calculate monthly imbalance volumes and penalties.

3. The difference between the monthly sum of the daily determined use figures and the prorated monthly metered use for each aggregator's customers will be the "operating imbalance." The operating imbalance will be disposed of during the next month. However, operating imbalances of more than 10 percent of monthly use can be disposed of over two months.

4. By 5:00 p.m. on the day before an Operational Flow Order or Emergency Flow Order, PG&E will provide an additional forecast to aggregators for their customers' next-day usage. Aggregators will be required to balance against that forecast during the OFO or EFO.

5. When an aggregator collects PG&E transportation revenue from customers under the "consolidated payment" option, PG&E will hold the aggregator responsible for late payment or non-payment [*227] to PG&E if the customer can demonstrate that it has paid the aggregator in full and on time. PG&E will not hold the customer responsible.

6. The following recommendations were made in order to provide clear, prompt, and responsive information

to address customer concerns:

a. PG&E and the aggregators will negotiate the establishment of joint communications protocols, to allow seamless call and information transfers.

b. PG&E and the aggregators will negotiate an industry "decision tree" for screening customer inquiries, to determine the party responsible for responding to the customer.

K. Core Wholesale Customers

1. Wholesale customers have the obligation to plan to meet their own core loads.

2. Existing wholesale customers, Palo Alto and Coalinga, will have a one-time option at the implementation of the **Gas Accord** to subscribe, on behalf of their core customers, for up to 6.5 MMcf/d (6.6 Mdth/d) of firm capacity on the Malin to on-system path at vintaged rates.

3. Existing wholesale customers will have the right to a share of storage capacity. They will get first priority from the storage capacity allocated to the Unbundled Storage Program, equal to their proportional [*228] share of the core load. They must reserve inventory, injection, and withdrawal proportionately together and they will pay the equivalent core rate for storage. Any storage cost will be added to the wholesale customer's transportation rate. They will have the same storage rights as other entities serving core customers and they may contract for storage through the Unbundled Storage Program to serve their noncore customers.

L. Procurement Incentive Mechanisms

1. For the period June 1, 1994, through December 31, 1997, PG&E will recover procurement and transportation costs consistent with the revised CPIM mechanism negotiated with DRA in 1996, and submitted as testimony by PG&E on April 23, 1996, in Application 94-12-039. As a result, this will resolve core procurement reasonableness for such period. Further, as part of such testimony, PG&E will forego its right to seek recovery of the reservation charges associated with the 150 Mmcf/d Transwestern core reservation for the periods 1992-1997.

2. A post-1997 procurement incentive mechanism will be based on the following parameters:

a. The pre-1998 CPIM agreement with DRA will be used as a model for the new incentive mechanism.
[*229]
b. The mechanism will be modified to include intrastate core capacity use (both firm and as-available).

c. The mechanism will be modified to allow for the opportunity to recover the cost of Transwestern reservation charges for 150 Mmcf/d, as well as other Southwest interstate capacity requirements that the core may require.

d. PG&E will develop a procedure to recover the costs associated with diversion and balancing penalties in rates that may occur under extreme weather or other extraordinary circumstances.

e. Based on the above parameters, PG&E and DRA will agree on the detailed substance of their post-1997 mechanism and amend this **Gas Accord** Settlement filing with the CPUC.

M. Core Subscription

1. Operations

a. Core and core subscription customers will be served by PG&E through a single supply portfolio.

b. Capacity reservations, nominations, and balancing will take place for the portfolio as a whole.

c. Core subscription customers will be assumed to use a proportional share of reserved interstate, Canadian and intrastate capacity.

d. Core subscription customers will be assumed to use a proportional share of the core portfolio's flowing supplies.

[*230] e. Transmission service priority for core subscription customers under emergency conditions will be the same as the priority of firm intrastate transmission service.

2. Pricing

a. Core subscription rates will be volumetric.

b. The intrastate transmission capacity charges for core subscription will be based on the transmission rates for the noncore market. That is, core subscription will not receive vintaged Malin to on-system prices. Core subscription revenues above the core subscription's proportionate share of the core portfolio's intrastate capacity costs will be returned to core customers served from the portfolio.

c. The PGT capacity costs for core subscription will be set at a weighted average (based on the available capacity) of the FTS-1 "Noncore" and the FTS-1 "Expansion Shipper" reservation rates, as specified in PGT's FERC-approved tariffs. Core subscription revenues above the core subscription's proportionate share of the core portfolio's PGT capacity costs will be returned to core customers served from the portfolio.

d. The cost of southwest pipeline capacity for core subscription is set at its cost.

e. The Canadian capacity charges for core subscription [*231] will be at the as-billed rate.

f. There will be a surcharge on core subscription rates of $0.07/Dth beginning January 1, 1998, to fund activities associated with program phase-out. Unspent revenues from the surcharge remaining after the core subscription program is discontinued will be returned to the core subscription customers which initially paid the surcharge.

g. Each core subscription customer will be responsible for any customer-specific penalties for failing to curtail use when requested by PG&E under the involuntary diversion provisions. Core subscription customers will not be responsible for any involuntary diversion penalties incurred by the core portfolio.

h. Except as just described, the core subscription rate will include core subscription's pro rata share of all core portfolio costs. Among other things, this includes Southwest interstate and Canadian capacity costs, as well as any imbalance charges, voluntary diversion payments, and costs or credits associated with the risk-sharing provisions of the core procurement incentive mechanism.

i. The core subscription rate will be set monthly based on a forecast of the core portfolio costs.

j. The core subscription [*232] monthly commodity price will be set at the forecasted average cost of core portfolio flowing supplies (no gas out of storage), adjusted as necessary to reflect any prior months' forecast error in the core portfolio commodity cost.

k. The core subscription rate will also be adjusted as necessary to reflect any prior period forecast errors associated with Canadian, interstate and intrastate capacity (net of brokering revenues).

l. Adopted shrinkage costs will be collected from core subscription customers.

m. Balancing account treatment for core subscription commodity, interstate and Canadian capacity, and shrinkage will be eliminated prospectively.

n. The core subscription rate will include a component to amortize the accrued balances from the current balancing accounts.

o. PG&E's noncore brokerage fee will remain at $0.0382 per decatherm, with balancing account treatment. Balances will continue to be allocated equal cents per therm to all noncore customers.

3. Eligibility for Core Subscription Service

Any noncore customer on PG&E's system, excluding UEG, is eligible for core subscription service.

4. Core Subscription Service Phaseout

a. Core subscription service [*233] is to expire within three years after implementation of the **Gas Accord.** At that time, customers wishing to remain PG&E procurement customers must elect to become core customers.

b. Parties may propose cost-based rate design changes in a future BCAP to mitigate the price impact on such customers who choose core status.

c. PG&E will conduct a marketing campaign to ensure that core subscription customers are aware of the competitive procurement alternatives available to them. The cost of the marketing campaign will be offset against the revenues from the $0.07/Dth surcharge.

5. Contract Terms

a. One-year term.

b. Current contracts will remain in effect until their expiration on July 1, 1997, except that current core subscription customers will be allowed to change suppliers before the expirations of their current contracts.

6. If the core subscription program participation (numbers of customers or contracted load) increases by more than ten percent (35 customers or 4 Mmcf/d), the parties will confer to consider possible responses.

N. Changing PG&E's Role in Northern California Gas Production

1. PG&E has had a strong presence in the northern California gas [*234] production industry both as the largest purchaser of gas and the largest gas gatherer. The **Gas Accord** proposes to reshape that role and seeks approval of the principles advocated here. Many of the implementation details that underlie these changes will of necessity be pan of separate proceeding(s).

PG&E and California producers intend to provide for efficient operation of the facilities used to bring California gas to market and to extend the economic life of California gas production.

2. PG&E proposes several principles that would apply to northern California gas production. They are:

a. The mutual release of all California production gas procurement contracts held by PG&E.

b. PG&E will support the formation of a non-utility cooperative run and managed by an association of producers (the Cooperative) or of a utility corporation run and managed by an association of producers (the Utility) to purchase and operate the gas gathering system. The Utility or Cooperative shall protect producer interests through an opportunity to participate in ownership and in governance; to have access to information; and to participate in profits, if any. PG&E's support is limited to a gas gathering [*235] entity. PG&E will not seek to spin-down the gathering facilities to an unregulated affiliate.

c. The sale of as many of the gas gathering facilities as possible to the Cooperative or the Utility, or to individual producers who are served by those facilities. Assets presently designated as gathering that are needed to provide safe and reliable transmission or distribution service will be retained and redesignated. PG&E will identify and connect producers on redesignated portions of the gathering system to the Utility/Cooperative gathering system(s) to assure access to market.

d. Should the Cooperative or the Utility not be formed or not purchase all the facilities, PG&E shall divest as many facilities as possible to producers where those facilities are only used by those producers.

e. If gathering facilities cannot be divested at a fair market price, PG&E will continue to own and maintain those facilities while recovering the ongoing costs of such facilities directly from producers that use them through a gathering charge. The level of the gathering charges will not exceed the difference between the California path rate and the lowest noncore transmission path connected to interstate [*236] gas supplies.

f. Where the Utility, the Cooperative, or individual producers acquire or provide their own gathering, the California path rate will be reduced by a cost-based credit. The cost-based credit shall be volumetric and shall be afforded to producers on a basis that reflects facilities acquired and costs avoided.

g. Approval of the sale of gas gathering facilities is pursuant to Section 851 of the California Public Utilities Code, on such terms and conditions as are mutually acceptable to the parties. To the extent there is a gain-on-sale related to the disposition of gathering facilities, the gains will be shared 95 percent ratepayer and 5 percent shareholder. To the extent there is a loss-on-sale, PG&E's shareholders will absorb 100 percent of the losses. In determining whether or not a gain-or loss-on-sale has occurred, PG&E will use a net book value based on the depreciation methodology outlined in Decision 89-12-016, the gas gathering decision. Gains would be included in an interest bearing balancing account, reflected in rates in the appropriate rate proceeding. Any environmental clean-up necessary for the sale will be recoverable via the Hazardous Substance Mechanism [*237] balancing account or through the appropriate mechanism as may be authorized by the Commission.

h. Approval and implementation of a standard California Production Balancing Agreement to meet one of PG&E's goals of improving the efficient use of its gas transportation system by reducing delays caused by adjustments when wellhead meter data do not match scheduled volumes. This will be effected by filing a pro forma agreement in an advice filing, subject to protest by producers.

i. Cooperate with the California gas producer community to develop options that will allow gas gatherers access to pipeline pressure data to maximize gathering system operational flexibility and to assist with the management of production imbalances.

j. Approval and implementation of a standard California Production Interconnection and Operating Agreement to apply consistent requirements whenever facilities owned by producers, by the Utility, or by the Cooperative are interconnected with PG&E's system for the purpose of gas transportation and authorization of an operations and maintenance fee, where applicable. Both will be effected through an advice filing, subject to protest by producers.

k. Any California-produced [*238] gas that PG&E buys outside of its existing contracts will meet the same quality standards as all other transported California-produced gas. PG&E will endeavor to continue its historic practice of transporting low-Btu gas to the extent physically possible, based on historical volumes. California produced gas that does not meet PG&E's minimum heating value requirement and/or gas quality specifications as set forth in PG&E's Rule 21 that is sold directly to end-use customers of PG&E is exempt from the residual load service tariff.

l. Should the Utility form for the purpose of acquiring and operating the gas gathering system, PG&E will support a filing for "light-handed" regulation for the Utility by the commission. "Light-handed regulation" shall be consistent with protecting producer interests through the provision of gathering services at the lowest reasonable cost; participation in ownership; participation in governance; access to information; assurances against discrimination; and participation in profits. PG&E's support for "light-handed" regulation is limited to a gas gathering entity.

3. The implementation of the **Gas Accord** could affect the employees of PG&E. With respect [*239] to PG&E's International Brotherhood of Electrical Workers (IBEW) workforce, PG&E will work with the IBEW to minimize the impact on employees. In the event that PG&E sells gas gathering facilities, as discussed above, and the sale results in the need to reduce the workforce, PG&E may offer a Voluntary Severance Incentive, a Voluntary Retirement Incentive, retraining, and other employee options, subject to negotiation with the IBEW local 1245.

V. LITIGATION RESOLUTIONA. Objectives

To resolve the outstanding proceedings relating to PG&E's natural gas operations as a means of transitioning to a restructured, more competitive gas business. Settlement of all these cases and the outstanding issues in these cases pursuant to the provisions below is a prerequisite to implementation of the **Gas Accord.B. Regulatory Cases Addressed by the Accord**

1. The **Gas Accord** settles and resolves the outstanding gas issues in the following proceedings, except as otherwise noted in this document:

a. PG&E's 1992 through 1995 gas reasonableness cases, Applications 93-04-011, 94-04-002, 95-04-002, and 96-04-001;

b. All issues in Phases 1, 2, and 3 of the combined Pipeline Expansion [*240] Project Reasonableness/Interstate Transition Cost Surcharge proceeding, and also the alleged Rule 1 violation, covered in Applications 92-12-043, 93-03-038, 94-05-035, 94-06-034, 94-09-056, and 94-06-044;

c. All issues regarding the reasonableness of noncore capacity brokering from January 1, 1996, through December 31, 1997. (Noncore and core capacity brokering for 1993-1994 is addressed in 1.b above. Noncore capacity brokering for 1995 is addressed in 1.a above. Core capacity brokering practices from June 1, 1994, to December 31, 1997, are addressed through PG&E's revised CPIM);

d. All issues in the Core Procurement Incentive Mechanism case, Application 94-12-039;

e. The EAD shortfall issues addressed in Applications 92-07-047, 92-07-049, 95-02-008, and 95-02-010;

f. Phase 2 of PG&E's BCAP Application 94-11-015; and

g. All issues pertaining to the reasonableness, restructuring, and revision of PG&E's transmission, storage, and core procurement practices, rates, and services in various statewide rulemaking and investigation dockets, R.88-08-018, R.90-02-008, R.92-12-016, and I.92-12-017.

2. PG&E has omitted the Canadian procurement (including the effects on northwest, [*241] geothermal and QF purchases), Canadian Decontracting and Restructuring, ANG and NOVA capacity, Affiliate Investigations, CIG sequencing, UEG curtailment, and Southwest procurement (including the Satrap investigation) issues in the 1991-1994 gas reasonableness cases from the list of financial concessions. These issues have been settled separately through May 1994, and the settlements have been filed with the CPUC. Therefore, they are not included in the financial concessions being considered as part of the **Gas Accord.**

C. Settlement of Regulatory Cases and PG&E Financial Concessions

1. Transwestern Pipeline Capacity Charges - Core 150 Mmcf/d Contract
(A.93-04-011, 94-04-002, 94-12-039, 95-04-002, 96-04-001, and PG&E's application covering reasonableness for 1996 and 1997, when filed) PG&E will not seek to recover any pipeline demand charges associated with the core portion of the Transwestern contract from the initiation of the contract through December 31, 1997, consistent with PG&E's revised CPIM submitted on April 23, 1996. (See Section IV.L.) For the period after 1997, PG&E will recover Transwestern demand charges for the balance of the Transwestern contract term in [*242] accordance with a successor CPIM which will be implemented January 1, 1998. Accordingly, if the **Gas Accord,** including PG&E's revised CPIM, is approved, PG&E will withdraw any appeal of Decision 95-12-046.

2. ANG and NOVA Pipeline Capacity Charges
(A.94-12-039, 95-04-002, 96-04-001, and PG&E's application covering reasonableness for 1996 and 1997, when filed)
For the period from June 1, 1994, through December 31, 1997, PG&E will recover core ANG and NOVA capacity demand charges in accordance with PG&E's revised CPIM. (See Section IV.L.) For the period after 1997, PG&E will recover ANG and NOVA demand charges for the balance of the ANG and NOVA contract terms at full ABR in accordance with a successor CPIM which will be implemented January 1, 1998.

3. transwestern Pipeline Capacity — UEG 50 Mmcf/d Contract
(A.93-04-011, 94-04-002, 95-04-002, and 96-04-001)
PG&E agrees to resolve the UEG Transwestern Capacity of 50 Mdth/d as follows: PG&E will not seek to recover from ratepayers the reservation charges associated with the 50 Mdth/d of UEG Transwestern capacity incurred through July 31, 1993. Recovery of reservation charges from August 1993 through implementation of the Power [*243] Exchange (PX) will be determined by comparing UEG's monthly commodity and volumetric interstate transportation costs associated with UEG's 50 Mdth/d of Transwestern capacity contract to a market benchmark based on California border indices. The benchmark will be calculated by multiplying an average of Topock gas price indices by the volumes transported by UEG for the month on the 50 Mdth/d of Transwestern capacity. The difference between the benchmark and the UEG commodity and the volumetric interstate transportation costs will be the amount of Transwestern reservation costs PG&E will be allowed to recover. The average border price will be determined by a simple average of 30 day Topock gas price indices from the following publications: Gas Daily, Natural Gas Weekly and Natural Gas Intelligence Gas Price Index. Recovery of reservation charges after implementation of the PX will not be through the proposed Competitive Transition Charge (CTC) mechanism.

PG&E is entitled to all revenue from brokering UEG Transwestern capacity generated through the period of the contract.

For the period prior to December 31, 1995, PG&E would recover $3.7 million of its total Transwestern capacity [*244] costs plus brokering revenues. The appropriate adjustments will be made to PG&E's ECAC balancing account to reflect this agreement. It is further agreed that this agreement will set no precedent for the treatment of other capacity reservations that the UEG may incur from time to time.

4. Pipeline Expansion Project Reasonableness (PEPR)/Interstate Transition Cost Surcharge (ITCS) Proceeding
(A.92-12-043, 93-03-038, 94-05-035, 94-06-034, 94-09-056, 94-06-044, and 96-04-001)
Implementation of the terms and agreements of the **Gas Accord,** as proposed, settles all contested issues associated with Phases 1, 2, and 3, of the PEPR/ITCS case, and also Rule 1 allegations.

a. ITCS Account (Core portion)
PG&E will absorb 100 percent of the core portion of ITCS charges as currently defined, less brokering revenues, plus interest, from the inception of the ITCS account. Any ITCS costs that were recovered in rates from the core will be returned to the core. Consequently:

i. PG&E will not be responsible for any proposed additional Northern California ITCS costs or other penalties or remedies alleged in the PEPR/ITCS proceeding for the period addressed in such proceeding or subsequent [*245] periods; and

ii. No other ITCS, capacity assignments, revenue requirements, or similar "stranded costs" or penalties should be shifted to Northern California ratepayers or PG&E shareholders from Southern California, as alleged in the PEPR/ITCS proceeding, the SoCalGas BCAP (Application 96-03-031), and other proceedings.

b. ITCS Account (Noncore portion)
PG&E will absorb 50 percent of the noncore portion of ITCS charges as currently defined, less brokering revenues, plus interest, from the inception of the ITCS account. PG&E's liability is limited to 50 percent, and therefore, includes any rate reduction approved by the CPUC in response to Advice Letter 1952-G

Consequently:

i. PG&E will not be responsible for any proposed additional Northern California ITCS costs or other penalties or remedies alleged in the PEPR/ITCS proceeding for the period addressed in such proceeding or subsequent periods;

ii. No other ITCS, capacity assignments, revenue requirements, or similar "stranded costs" or penalties should be shifted to Northern California ratepayers or PG&E shareholders from Southern California, as alleged in the PEPR/ITCS proceeding, the SoCalGas BCAP (Application [*246] 96-03-031), and other proceedings.

iii. PG&E shall be entitled to recovery of 50 percent of ITCS charges through gas transportation rates. No ITCS charges shall be recovered through electric rates except those paid by PG&E's UEG as a noncore gas customer.

c. Pipeline Expansion Rates
PG&E agrees that, for ratemaking purposes, the initial capital cost of the PG&E portion of the PG&E/PGT Pipeline Expansion Project will be $736 million. In recalculating rates using the lower Line 401 capital costs, PG&E will use the Company's utility corporate cost of capital and capital structure. The rates and terms of service for the Malin to on- and off-system paths, which include a Line 401 component, and the major assumptions used in deriving the Line 401 component, are as specified in Sections II.I and IV. The rates and terms of service for G-XF firm service are as specified in Section II.B.1. Other options available to firm Expansion shippers are described in Section II.F.1.c.

d. Backbone Credit
PG&E agrees not to collect in future rates the balance of the Backbone Credit Memorandum Account. As of the date the **Gas Accord** is approved by the CPUC, PG&E will not provide a backbone [*247] credit to any shipper and will remove the backbone crediting provisions from its tariffs. The Backbone Credit Memorandum Account will be terminated as of the date the **Gas Accord** is approved.

5. EAD Contacts
(A.92-07-047, 92-07-049, 95-02-008, and 95-02-010)
For the period from the contracts' inception dates until the date the **Gas Accord** rate structure is implemented, PG&E will collect 75 percent of EAD revenue shortfalls by operation of the Noncore Fixed Cost Account. This covers all EAD contracts, except those with Gaylord and Posco, approved in Decisions 95-06-022 and 95-06-023, respectively. With respect to those contracts, PG&E will be at risk for 100 percent of EAD shortfall revenue. During the **Gas Accord** period, PG&E will not collect any EAD revenue shortfalls in rates. The Commission will not take any further action in and will close this consolidated proceeding.

6. BCAP Phase II
(A.94-11-015)
In PG&E's 1995 BCAP, SMUD proposed an unbundled backbone transmission rate. Decision 95-12-053, recognizing that there were issues that needed to be addressed prior to adopting such a rate, established a second phase in the BCAP. The Decision also recognized that these issues [*248] could potentially be resolved in the Accord, and therefore encouraged parties to enter into negotiations as part of the Accord process. Subsequent to the issuance of Decision 95-12-053, PG&E and SMUD have reached preliminary agreement for service that better meets SMUD's needs, as discussed in Section II.F.6. Subject to timely completing the definitive agreements and securing CPUC approval, this arrangement will resolve SMUD's Phase II BCAP issues. The **Gas Accord** provides the framework necessary for PG&E to negotiate to resolve any remaining concerns of other parties.

7. Remaining Reasonableness Issues
(A.93-04-011, 94-04-002, 95-04-002, and 96-04-001)
All core procurement cost recovery after May 1994 shall be in accordance with PG&E's revised CPIM. All other issues outstanding in reasonableness proceedings are deemed settled and no party shall seek or recommend any disallowance, sanction, or penalty associated any gas reasonableness issue, named or unnamed for years 1992 through 1995.

8. 1988 - 1990 Gas Reasonableness Issues
(A.91-04-003)
If the **Gas Accord** Settlement is finally adopted by the Commission, or adopted with modifications acceptable to PG&E and DRA, PG&E will [*249] permanently forego recovering from its ratepayers any of the disallowance ordered by Decision 94-03-050, which has been (or will be) refunded to ratepayers, notwithstanding the outcome of its pending lawsuit in Federal District court (Civil No. C-94-4381 WHO). In the event the Federal District Court issues a decision prior to a Commission decision on the **Gas Accord,** PG&E will not execute any court judgment or otherwise seek recovery of the disallowance and associated refunds ordered as a result of Decision 94-03-050, unless in PG&E's reasonable judgment, failure to do so would prejudice PG&E's right to said recovery. In the event PG&E seeks recovery of a refund in order to preserve its rights pending a Commission decision on the Accord, PG&E agrees to once again refund the disallowance to ratepayers upon final approval of the **Gas Accord** Settlement.

The UEG and noncore will receive their portion of the 1988-1990 disallowance ordered by Decision 94-03-050 upon approval of the refund plan pending before the Commission. UEG's portion of the 1988-1990 disallowance ordered by Decision 94-03-050 will be credited directly to the ECAC balancing account and will not be refunded to electric [*250] customers directly. This treatment will not have an effect on PG&E's electric rate freeze, and will be subject to the same provisions as other ECAC balances.

As part of the overall **Gas Accord** Settlement, the remaining phase III C issues in Application 91-04-003 associated with the 1988-1990 disallowance (BCAP Phase II) are resolved for $3.7 million inclusive of any interest through 1995. PG&E will credit its ECAC balancing account $3.7 million effective December 31, 1995. Interest would accrue from that date forward. This treatment will not have an effect on PG&E's electric rate freeze, and will be subject to the same provisions as other ECAC balances.

VI. ACCORD RATES

Table 1
Illustrative Rate Projections Under the **Gas Accord** — On–System
($ /Dth)

	1997	1998	1999	2000	2001	2002	Avg (1997–02)
Core (Bundled)							
Residential	5.61	5.62	5.75	5.79	5.93	6.07	5.79
Small Commercial	5.65	5.66	5.80	5.83	5.97	6.11	5.84
Large Commercial	3.93	3.92	4.02	4.01	4.11	4.21	4.03
Noncore (Firm Topock)							
Distribution	1.14	1.11	1.11	1.10	1.12	1.15	1.12
Transmission	0.48	0.45	0.43	0.40	0.41	0.42	0.43
UEG	0.42	0.39	0.38	0.36	0.36	0.37	0.38
COG	0.42	0.39	0.38	0.36	0.36	0.37	0.38
Coalinga	0.47	0.44	0.43	0.41	0.42	0.42	0.43
Palo Alto	0.42	0.40	0.38	0.36	0.37	0.38	0.39
Noncore (Firm Malin)							
Distribution	1.23	1.21	1.21	1.20	1.22	1.24	1.22
Transmission	0.57	0.54	0.53	0.50	0.51	0.51	0.53
UEG	0.51	0.49	0.48	0.45	0.46	0.46	0.48
COG	0.51	0.49	0.48	0.45	0.46	0.46	0.48
Coalinga	0.56	0.54	0.53	0.51	0.51	0.52	0.53
Palo Alto	0.52	0.49	0.48	0.46	0.47	0.47	0.48
Noncore (Firm California Gas)							
Distribution	1.10	1.06	1.06	1.04	1.07	1.09	1.07
Transmission	0.44	0.40	0.38	0.35	0.35	0.36	0.38
UEG	0.37	0.34	0.32	0.30	0.31	0.31	0.33
COG	0.37	0.34	0.32	0.30	0.31	0.31	0.33
Coalinga	0.43	0.39	0.37	0.35	0.36	0.37	0.38
Palo Alto	0.38	0.35	0.33	0.31	0.31	0.32	0.33

[*251]
Notes:
a) Some portions of these rates are guaranteed.
b) Core rates are bundled and include average backbone transmission costs, local transmission, distribution, storage, customer class charge, and a forecast of procurement and interstate pipeline demand charges.
c) Noncore rates include backbone transmission, local transmission, customer class charges, customer access charges and distribution charges.

Table 2
Firm Backbone Charge — Annual Rates (AFT)
MFV Rate Design
ON–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Malin to On–System – Core							
Reservation Charge	($ /Dth/mo)	2.20	2.23	2.27	2.32	2.36	2.41
Usage Charge	($ /Dth)	0.041	0.042	0.043	0.043	0.044	0.045
Total	($ /Dth@Full Contract)	0.113	0.115	0.118	0.119	0.122	0.124

Table 2
Firm Backbone Charge — Annual Rates (AFT)
MFV Rate Design
ON–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Malin to On–System							
Reservation Charge	($ /Dth/mo)	3.95	4.21	4.43	4.52	4.61	4.69
Usage Charge	($ /Dth)	0.108	0.114	0.119	0.118	0.117	0.115
Total	($ /Dth@Full Contract)	0.238	0.253	0.265	0.267	0.269	0.269
Topock to On–System							
Reservation Charge	($ /Dth/mo)	3.16	3.45	3.69	3.81	3.86	3.91
Usage Charge	($ /Dth)	0.041	0.042	0.043	0.044	0.045	0.046
Total	($ /Dth@Full Contract)	0.145	0.155	0.164	0.169	0.172	0.175
California Gas and On–System Storage to On–System							
Reservation Charge	($ /Dth/mo)	2.00	2.11	2.20	2.26	2.29	2.33
Usage Charge	($ /Dth)	0.036	0.038	0.039	0.039	0.039	0.039
Total	($ /Dth@Full Contract)	0.102	0.107	0.111	0.113	0.114	0.116

[*252]
Notes:
a) These rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
b) On–system backbone transmission charges are based on an 87.5% load factor.
c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100% load factor.
d) Customers delivering gas to storage facilities pay the applicable backbone transmission on–system rate from Malin, Topock or California production.
e) Core and core wholesale are assigned 606.5 MMcf/d (615.6 Mdth/d) of capacity on Line 400 at vintaged rates. These rates are shown under "Malin to On–System – Core". Any additional usage from Malin by core or core wholesale must be on the "Malin to on–system path".
f) These rates are subject to change during the Accord period pursuant only to the z–factor provisions of Section II.I.7. Malin to on–system charges include a phase–in of Line 401 costs as described in Section II.I.3.
g) Gathering facilities are assumed to be fully depreciated by January [*253] 1, 1997. Gathering O&M expenses are included as part of the common backbone component.
AFT continued next page

Table 3
Firm Backbone Transportation — Annual Rates (AFT)
SFV Rate Design
ON–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Malin to On–System Core							
Reservation Charge	($ /Dth/mo)	3.19	3.24	3.30	3.37	3.44	3.52
Usage Charge	($ /Dth)	0.008	0.008	0.009	0.009	0.009	0.009
Total	($ /Dth@Full Contract)	0.113	0.115	0.117	0.120	0.122	0.125
Malin to On–System							
Reservation Charge	($ /Dth/mo)	7.01	7.48	7.83	7.90	7.95	7.96

Table 3
Firm Backbone Transportation — Annual Rates (AFT)
SFV Rate Design
ON–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Usage Charge	($ /Dth)	0.007	0.007	0.007	0.007	0.007	0.007
Total	($ /Dth@Full Contract)	0.237	0.253	0.264	0.267	0.268	0.269
Topock to On–System							
Reservation Charge	($ /Dth/mo)	4.31	4.63	4.89	5.03	5.11	5.19
Usage Charge	($ /Dth)	0.004	0.004	0.004	0.004	0.004	0.004
Total	($ /Dth@Full Contract)	0.146	0.156	0.165	0.169	0.172	0.175
California Gas and On–System Storage to On–System							
Reservation Charge	($ /Dth/mo)	3.02	3.18	3.30	3.36	3.39	3.43
Usage Charge	($ /Dth)	0.003	0.003	0.003	0.003	0.003	0.003
Total	($ /Dth@Full Contract)	0.102	0.107	0.112	0.113	0.115	0.116

Notes:
a) These rates are only the backbone transmission charge component [*254] of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
b) On–system backbone transmission shares are based on an 87.5% load factor.
c) the "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100% load factor.
d) Customers delivering gas to storage facilities pay the applicable backbone transmission on–system rate from Malin, Topock or California production.
e) Core and core wholesale are assigned 606.5 MMcf/d (615.6 Mdth/d) of capacity on Line 400 at vintage rates. Any additional usage from Malin by core or core wholesale must be on the Malin to on–system path.
f) These rates are subject to change during the Accord period pursuant only to the z–factor provisions of Section II.I.7. Malin to on–system charges include a phase–in of Line 401 costs as described in Section II.I.3.
g) Gathering facilities are assumed to be fully depreciated by January 1, 1997. Gathering O&M are included as part of the common backbone component.

Table 4
Firm Backbone Transportation Charges — Seasonal Rates (SFT)
MFV Rate Design
ON–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Malin to On–System							
Reservation Charge	($ /Dth/mo)	4.74	5.06	5.31	5.43	5.53	5.63
Usage Charge	($ /Dth)	0.129	0.137	0.143	0.142	0.140	0.138
Total	($ /Dth@Full Contract)	0.285	0.303	0.318	0.320	0.322	0.323
Topock to On–System							
Reservation Charge	($ /Dth/mo)	3.79	4.14	4.42	4.57	4.63	4.69
Usage Charge	($ /Dth)	0.050	0.051	0.052	0.053	0.054	0.055
Total	($ /Dth@Full	0.175	0.187	0.197	0.203	0.206	0.209

Table 4
Firm Backbone Transportation Charges — Seasonal Rates (SFT)
MFV Rate Design
ON–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
	Contract)						
California Gas and On–System Storage to On–System							
Reservation Charge	($ /Dth/mo)	2.40	2.53	2.64	2.71	2.75	2.79
Usage Charge	($ /Dth)	0.044	0.046	0.047	0.047	0.047	0.047
Total	($ /Dth@Full Contract)	0.123	0.129	0.134	0.136	0.137	0.139

[*255]
Notes:
a) Firm Seasonal rates are 120% of Firm Annual rates.
b) These rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
c) The "Total" rows represent the average backbone transmission cost incurred by a firm shipper that uses its full contract quantity at a 100% load factor.
d) Customers delivering gas to storage facilities pay the applicable backbone transmission on–system rate from Malin, Topock or California production.
e) These rates are subject to change during the Accord period pursuant only to the z–factor provisions of Section II.I.7. Malin to on–system rates include phase–in of Line 401 costs as described in Section II.I.3.
f) Gathering facilities are assumed to be fully depreciated by January 1, 1997. Gathering O&M expenses are included as part of the common backbone component.
g) For the period July 1997 through March 1998, core will receive seasonal service (SFT) from Topock at a rate that is 110% of annual firm rates (AFT).
SFT continued next page

Table 5
Firm Backbone Transportation Charges — Seasonal Rates (SFT)
SFV Rate Design
ON–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Malin to On–System							
Reservation Charge	($ /Dth/mo)	8.41	8.97	9.39	9.48	9.53	9.55
Usage Charge	($ /Dth)	0.008	0.008	0.008	0.009	0.009	0.009
Total	($ /Dth@ Full Contract)	0.285	0.303	0.317	0.321	0.322	0.323
Topock to On–System							
Reservation Charge	($ /Dth/mo)	5.17	5.55	5.86	6.04	6.13	6.23
Usage Charge	($ /Dth)	0.004	0.004	0.004	0.004	0.005	0.005
Total	($ /Dth@ Full Contract)	0.174	0.187	0.197	0.203	0.207	0.210
California Gas and On–System Storage to On–System							
Reservation Charge	($ /Dth/mo)	3.62	3.81	3.96	4.03	4.07	4.11

Table 5
Firm Backbone Transportation Charges — Seasonal Rates (SFT)
SFV Rate Design
ON–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Usage Charge	($ /Dth)	0.004	0.004	0.004	0.004	0.004	0.004
Total	($ /Dth@ Full Contract)	0.123	0.129	0.134	0.136	0.138	0.139

[*256]
Notes:
a) Firm Seasonal rates are 120% of Firm Annual rates.
b) These rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
c) The "Total" rows represent the average backbone transmission cost incurred by a firm shipper that uses its full contract quantity at a 100% load factor.
d) Customers delivering gas to storage facilities pay the applicable backbone transmission on–system rate from Malin, Topock or California production.
e) These rates are subject to change during the Accord period pursuant only to the z–factor provisions of Section II.I.7. Malin to on–system rates include a phase–in of Line 401 costs described in Section II.I.3.
f) Gathering facilities are assumed to be fully depreciated by January 1, 1997. Gathering O&M expenses are included as part of the common backbone component.
g) For the period July 1997 through March 1998, core will receive seasonal service (SFT) from Topock at a rate that is 110% of annual firm rates (AFT).

Table 6
As–Available Backbone Transportation (AA)
ON–SYSTEM DELIVERIES

	1997	1998 1/1–3/31	1998 4/1–12/31	1999	2000	2001	2002
Malin to On–System Usage Charge ($ /Dth)	0.261	0.278	0.303	0.317	0.320	0.322	0.323
Topock to On–System Usage Charge ($ /Dth)	0.160	0.171	0.187	0.197	0.203	0.206	0.209
California Gas to On–System Usage Charge ($ /Dth)	0.112	0.118	0.129	0.134	0.136	0.138	0.139
On–System Storage to On–System Usage Charge ($ /Dth)	0.000	0.000	0.000	0.000	0.000	0.000	0.000

[*257]
Notes:
a) As–Available rates are 110% of Firm–Annual rates through March 31, 1998, and 120% thereafter.
b) These rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
c) Customers delivering gas to storage facilities pay the applicable backbone transmission on–system rate from Malin, Topock or California production.

d) Consistent with current CPUC rules, there will not be a transmission charge for transmission from storage unless firm transmission capacity is required to schedule the movement of the natural gas from the storage facility.
e) These rates are subject to change during the Accord period pursuant only to the z–factor provisions of Section II.I.7. Malin to on–system rates include a phase–in of Line 401 costs described in Section II.I.3.
f) Gathering facilities are assumed to be fully depreciated by January 1, 1997. Gathering O&M expenses are included as part of the common backbone component.

Table 7
Firm Backbone Transportation Charges — Annual Rates (AFT–Off)
MFV Rate Design
OFF–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Malin to Off–System							
Reservation Charge	($ /Dth/mo)	5.52	5.46	5.39	5.32	5.25	5.18
Usage Charge	($ /Dth)	0.216	0.205	0.195	0.185	0.175	0.165
Total	($ /Dth@Full Contract)	0.397	0.384	0.372	0.360	0.348	0.335
Topock to Off–System							
Reservation Charge	($ /Dth/mo)	3.16	3.45	3.69	3.81	3.86	3.91
Usage Charge	($ /Dth)	0.041	0.042	0.043	0.044	0.045	0.046
Total	($ /Dth@Full Contract)	0.145	0.155	0.164	0.169	0.172	0.175
California Gas and On–System Storage to Off–System							
Reservation Charge	($ /Dth/mo)	5.52	5.46	5.39	5.32	5.25	5.18
Usage Charge	($ /Dth)	0.216	0.205	0.195	0.185	0.175	0.165
Total	($ /Dth@Full Contract)	0.397	0.384	0.372	0.360	0.348	0.335

[*258]
Notes:
a) These rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
b) Except for Malin to off–system, and California gas to off–system, backbone transmission rates are based on an 87.5% load factor.
c) The "Total" rows represent the average backbone transmission cost incurred by a firm shipper that uses its full contract quantity at a 100% load factor.
d) Malin to off–system charges are based on Line 401's embedded costs and a 95% load factor.
e) These rates are subject to change during the Accord period pursuant only to the z–factor provisions of Section II.I.7.
f) Gathering facilities are assumed to be fully depreciated by January 1, 1997. Gathering O&M expenses are included as part of the common backbone component.
g) California gas and storage to off–system are assumed to flow on Line 401, and are priced at the Line 401 rate.

AFT–Off continued next page

Table 8
Firm Backbone Transportation Charges — Annual Rates (AFT–Off)
SFV Rate Design
OFF–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Malin to Off–System							
Reservation Charge	($ /Dth/mo)	11.66	11.28	10.91	10.55	10.19	9.83
Usage Charge	($ /Dth)	0.004	0.004	0.004	0.004	0.004	0.004
Total	($ /Dth@Full Contract)	0.387	0.375	0.363	0.351	0.339	0.327
Topock to Off–System							
Reservation Charge	($ /Dth/mo)	4.31	4.63	4.89	5.03	5.11	5.19
Usage Charge	($ /Dth)	0.004	0.004	0.004	0.004	0.004	0.004
Total	($ /Dth@Full Contract)	0.146	0.156	0.165	0.169	0.172	0.175
California Gas and On–System Storage to Off–System							
Reservation Charge	($ /Dth/mo)	11.66	11.28	10.91	10.55	10.19	9.83
Usage Charge	($ /Dth)	0.004	0.004	0.004	0.004	0.004	0.004
Total	($ /Dth@Full Contract)	0.387	0.375	0.363	0.351	0.339	0.327

[*259]
Notes:
a) These rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
b) Except for Malin to off–system, and California gas to off–system, backbone transmission rates are based on an 87.5% load factor.
c) The "Total" rows represent the average backbone transmission cost incurred by a firm shipper that uses its full contract quantity at a 100% load factor.
d) Malin to off–system charges are based on the embedded cost of Line 401 and a 95% load factor.
e) These rates are subject to change during the Accord period pursuant only to the z–factor provisions of Section II.I.7.
f) Gathering facilities are assumed to be fully depreciated by January 1, 1997. Gathering O&M expenses are included as part of the common backbone component.
g) California gas and storage to off–system are assumed to flow on Line 401, and are priced at the Line 401 rate.

Table 9
As–Available Backbone Transportation (AA–Off)
OFF–SYSTEM DELIVERIES

		1997	1998 1/1–3/31	1998 4/1–12/31	1999	2000	2001	2002
Malin to Off–System								
Usage Charge	($ /Dth)	0.437	0.424	0.462	0.447	0.433	0.418	0.403
Topock to Off–System								
Usage Charge	($ /Dth)	0.160	0.171	0.187	0.197	0.203	0.206	0.209

Table 9
As–Available Backbone Transportation (AA–Off)
OFF–SYSTEM DELIVERIES

		1997	1998 1/1–3/31	1998 4/1–12/31	1999	2000	2001	2002
California Gas and On–System Storage to Off–System								
Usage Charge	($ /Dth)	0.437	0.424	0.462	0.447	0.433	0.418	0.403

[*260]
Notes:
a) These rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
b) As–Available rates are 110% of Firm–Annual rates through March 31, 1998, and 120% thereafter.
c) Gathering facilities are assumed to be fully depreciated by January 1, 1997. Gathering O&M expenses are included as part of the common backbone component.
d) California gas and storage to off–system is assumed to flow on Line 401, and is priced at the Line 401 rate.

Table 10
Firm Transportation– Expansion Shippers – Annual Rates (G–XF)
MFV Rate Design
OFF–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Malin to Off–System							
Reservation Charge	($ /Dth/mo)	5.52	5.46	5.39	5.32	5.25	5.18
Usage Charge	($ /Dth)	0.216	0.205	0.195	0.185	0.175	0.165
Total	($ /Dth@Full Contract)	0.397	0.384	0.372	0.360	0.348	0.335

Notes:
a) These rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer access charges, customer access charges, distribution [*261] charges, storage charges, and shrinkage charges.
b) The "Total" rows represent the average backbone transmission cost incurred by a firm shipper that uses its full contract quantity at a 100% load factor.
c) G–XF charges are based on the embedded cost of Line 401 and a 95% load factor.
d) These rates are subject to change during the Accord period pursuant only to the z–factor provisions of Section II.I.7.

Table 11
Firm Transportation– Expansion Shippers – Annual Rates (G–XF)
SFV Rate Design
OFF–SYSTEM DELIVERIES

		1997	1998	1999	2000	2001	2002
Malin to Off–System							
Reservation Charge	($ /Dth/mo)	11.66	11.28	10.91	10.55	10.19	9.83
Usage Charge	($ /Dth)	0.004	0.004	0.004	0.004	0.004	0.004
Total	($ /Dth@Full Contract)	0.387	0.375	0.363	0.351	0.339	0.327

Notes:
a) These rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.
b) The "Total" rows represent the average backbone transmission cost incurred by a firm shipper that uses its full contract quantity at a 100% load factor.
[*262] c) G-XF charges are based on the embedded cost of Line 401 and a 95% load factor.
d) These rates are subject to change during the Accord period pursuant only to the z-factor provisions of Section II.I.7.

Table 12
Storage Rates

Firm Storage Service (FS)	Capacity	Withdrawal	
Reservation Charges			
Annual Reservation Charge	$ 0.746/Dth	$ 9.651/Dth/day	
Variable Charges			
Variable Charge	$ 0.039/Dth	$ 0.039/Dth	
Negotiated Firm Storage (NFS)	Injection	Inventory	Withdrawal
Maximum Rate			
Volumetric Rate	$ 8.149/Dth	$ 1.144/Dth	$ 4.923/Dth
Negotiated As-Available Storage (NAS)			
Maximum Rate			
Volumetric Rate	$ 8.149/Dth	$ 4.923/Dth	

Notes:
a) Rates for storage services are based on the costs of storage injection, inventory and withdrawal.
b) Firm Storage rates are subfunctionalized by a capacity (combined injection and inventory) charge and withdrawal charge. The capacity charge is calculated assuming recovery of both the injection and inventory revenue requirement over the annual inventory design capacity allocated to the unbundled storage program. The withdrawal charge is calculated based on recovery of the withdrawal revenue requirement over [*263] the daily withdrawal design capacity allocated to the unbundled storage program.
c) Firm Storage capacity and withdrawal charges are recovered through a reservation (fixed) and volumetric (variable) component.
d) Negotiated Firm rates may be one-part rates (volumetric) or two-part rates (reservation and variable), as negotiated between parties. The volumetric equivalent is shown above.
e) Negotiated As-available Storage Injection and Withdrawal rates are recovered through a volumetric charge only.
f) The flexibility inherent in this storage offer court result in stranded facilities and PG&E requires the opportunity to collect the value of the storage services. Negotiated rates (NFS and NAS) are capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program under all three subfunctions (e.g. inventory, injection, or withdrawal.) The maximum rates are based on a rate design assuming an average injection period of 30 days and an average withdrawal period of 7 days.
g) Negotiated Firm and As-available services are negotiable above a price floor representing PG&E's marginal cost of providing the service.
h) Rates will be implemented [*264] for the unbundled storage program in April 1, 1998.
i) The maximum annual charge for parking and lending is based on the annual cost of cycling one Dth of Firm Storage Gas assuming the full 214 day injection season and 151 day withdrawal season. The annual cycle cost is $0.89 per Dth.

Table 13
Local Transmission Rates
($ /Dth)

	1997	1998	1999	2000	2001	2002
Core	.254	.260	.267	.273	.280	.287
Noncore	.131	.135	.138	.141	.145	.149

Notes:
a) These rates are subject to change during the Accord period pursuant only to the z–factor provisions of Section II.I.7.
b) Rates for 1998–2002 escalate at 2.5 percent.
c) First year rates are based on 1996 GRC revenue requirement, 1995 BCAP cost allocation and throughput, and 57.8% of BCAP adopted APD adjustment.

Table 14
Illustrative Customer Class Charges
($ /Dth)

	1997	1998	1999	2000	2001	2002
Residential	.353	.224	.223	.121	.119	.118
Small Commercial	.404	.276	.276	.174	.175	.175
Large Commercial	.300	.200	.201	.099	.099	.100
Industrial Distribution	.207	.149	.122	.083	.084	.085
Industrial Transmission	.174	.127	.100	.061	.062	.062
UEG	.132	.093	.066	.039	.039	.039
Cogeneration	.132	.093	.066	.039	.039	.039
Wholesale						
Coalinga	.145	.100	.072	.045	.045	.045
Palo Alto	.136	.094	.066	.039	.039	.039

[*265]
Notes:
a) Customer class charges include no ITCS for core, and 50% of ITCS for noncore, as described in Section IV.B.4. Core rates include a refund of ITCS costs recovered prior to 1997.
b) Rates for 1997 consistent with 1995 BCAP decision. Rates for 1998–2002 do not escalate at 2.5%. Instead they represent forecast of individual balancing accounts. Actual rates will be determined in BCAPs or successor proceedings.
c) The UEG and cogeneration customer class charges include costs associated with cogeneration rate parity. See section III.C.5.

Table 15
1997 Customer Access Charge
for On–System Customers Directly Connected
to the Transmission System
($/Month)

Industrial	(Therms/ Month)	1997	1998	1999	2000	2001	2002
Tier 1	0 to 5,000	10.49	10.75	11.02	11.30	11.58	11.87
Tier 2	5,001 to 10,000	82.66	84.73	86.84	89.02	91.24	93.52
Tier 3	10,001 to 50,000	313.58	321.42	329.45	337.69	346.13	354.79

Table 15
1997 Customer Access Charge
for On-System Customers Directly Connected
to the Transmission System
($/Month)

		1997	1998	1999	2000	2001	2002
Tier 4	50,001 to 200,000	826.61	847.28	868.46	890.17	912.42	935.23
Tier 5	200,001 to 1,000,000	1,183.50	1,213.09	1,243.41	1,274.50	1,306.36	1,339.02
Tier 6	1,000,001 and above	3,440.30	3,526.31	3,614.47	3,704.83	3,797.45	3,892.38
UEG		113,083	115,910	118,808	121,778	124,822	127,943
Cogeneration ($ /Dth)		.00710	.00728	.00746	.00765	.00784	.00803
Wholesale							
Coalinga		908.67	931.39	954.67	978.54	1,003.00	1,028.08
Palo Alto		2,882.42	2,954.48	3,028.34	3,104.05	3,181.65	3,261.19

[*266]
Notes:
a) Customer access charges escalate at 2.5% per year.

Table 16
Forecast Distribution Rates
($ /Dth)

	1997	1998	1999	2000	2001	2002
Residential	2.53	2.59	2.66	2.72	2.79	2.86
Small Commercial	2.53	2.59	2.66	2.72	2.79	2.86
Large Commercial	.94	.96	.99	1.01	1.04	1.06
Industrial Distribution	.656	.672	.689	.706	.724	.742

Notes:
a) Core and noncore rates are distribution only.
b) Commercial and industrial rates shown are average distribution rates. Commercial and industrial distribution rates will be seasonally differentiated and include a monthly customer charge.
c) Illustrative rates, based on 2.5% escalation, are shown. Actual rates will be determined in BCAPs or successor proceedings.
d) There is no cogeneration rate shown, since cogenerators receive rate parity with UEG, which is transmission level service.
e) All rates exclude procurement and interstate transmission.

Table 17
Illustrative Bundled
1997 Core Transportation Rates
($ /Dth)

	Residential	Small Commercial	Large Commercial	Average Core
Intrastate Backbone Transmission	.148	.148	.130	.147
Intrastate Local Transmission	.254	.254	.254	.254
Customer class charge	.353	.404	.300	.363
Distribution	2.53	2.53	.945	2.45

Table 17
Illustrative Bundled
1997 Core Transportation Rates
($ /Dth)

	Residential	Small Commercial	Large Commercial	Average Core
Storage	.115	.115	.102	.115
Procurement	1.92	1.92	1.92	1.92
Interstate Transmission	.292	.281	.281	.289
Total	5.61	5.65	3.93	5.53

[*267]
Note:
a) Average backbone transmission rate based on expected core deliveries from Line 400, Line 300 and California gas production, based on the capacity assignments discussed in Section I.E.
b) Average core storage rates are based on core capacity reservations set forth in Section II.E.

Table 18
1997 Seasonal Volumetric Rates For Distribution Service Customers
($ /Dth)

	Summer Volumetric Rate	Winter Volumetric Rate	Average Volumetric Rate	Winter to Summer Ratio
Small Commercial	$ .166	$ .250	$ .212	1.50
Large Commercial	$ .065	$ .110	$ .089	1.70
Industrial Distribution	$ .048	$ .064	$ .056	1.35

Notes:
a) Rates exclude monthly customer charge.**APPENDIX CPRESENT VALUE OF GAS ACCORD BENEFITS**

TABLE 1 – CORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
RESIDENTIAL			
BACKBONE	0.0149	0.0157	0.0164
LOCAL TRANSMISSION	0.0254	0.0260	0.0267
CUSTOMER CLASS CHARGE	0.0353	0.0224	0.0223
DISTRIBUTION	0.2533	0.2533	0.2596
STORAGE	0.0116	0.0118	0.0121
SUBTOTAL RATE	0.3404	0.3292	0.3371
THROUGHPUT (Therms)	2,096,289	2,113,979	2,131,333
REVENUE	713,535	695,943	718,520
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	713,535	675,065	676,055
SMALL COMMERCIAL			
BACKBONE	0.0149	0.0157	0.0164
LOCAL TRANSMISSION	0.0254	0.0260	0.0267
CUSTOMER CLASS CHARGE	0.0405	0.0276	0.0276
DISTRIBUTION	0.2533	0.2533	0.2596
STORAGE	0.0116	0.0118	0.0121
SUBTOTAL RATE	0.3456	0.3344	0.3424

TABLE 1 – CORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
THROUGHPUT (Therms)	789,183	795,843	802,376
REVENUE	272,718	266,138	274,751
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	272,718	258,154	258,514
LARGE COMMERCIAL			
BACKBONE	0.0149	0.0157	0.0164
LOCAL TRANSMISSION	0.0254	0.0260	0.0267
CUSTOMER CLASS CHARGE	0.0300	0.0200	0.0201
DISTRIBUTION	0.0945	0.0945	0.0969
STORAGE	0.0102	0.0105	0.0108
SUBTOTAL RATE	0.1750	0.1668	0.1708
THROUGHPUT (Therms)	159,899	161,248	162,572
REVENUE	27,987	26,888	27,764
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	27,987	26,081	26,123
YEARLY TOTAL REVENUE	1,014,240	959,300	960,692
SIX YEAR TOTAL **GAS ACCORD**		$ 5,753,457	
SIX YEAR TOTAL BCAP (Table 2)		$ 5,824,019	

Discount Rate Equals 3% per year.

[*268]

TABLE 1 – CORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
RESIDENTIAL			
BACKBONE	0.0167	0.0169	0.0171
LOCAL TRANSMISSION	0.0273	0.0280	0.0287
CUSTOMER CLASS CHARGE	0.0121	0.0120	0.0119
DISTRIBUTION	0.2661	0.2728	0.2796
STORAGE	0.0124	0.0127	0.0131
SUBTOTAL RATE	0.3346	0.3424	0.3504
THROUGHPUT (Therms)	2,155,645	2,181,761	2,212,882
REVENUE	721,328	747,047	775,338
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	658,337	661,356	665,809
SMALL COMMERCIAL			
BACKBONE	0.0167	0.0169	0.0171
LOCAL TRANSMISSION	0.0273	0.0280	0.0287
CUSTOMER CLASS CHARGE	0.0174	0.0175	0.0175
DISTRIBUTION	0.2661	0.2728	0.2796

TABLE 1 – CORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
STORAGE	0.0124	0.0127	0.0131
SUBTOTAL RATE	0.3400	0.3479	0.3560
THROUGHPUT (Therms)	811,529	821,360	833,076
REVENUE	275,906	285,748	296,562
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	251,812	252,970	254,668
LARGE COMMERCIAL			
BACKBONE	0.0167	0.0169	0.0171
LOCAL TRANSMISSION	0.0273	0.0280	0.0287
CUSTOMER CLASS CHARGE	0.0099	0.0100	0.0100
DISTRIBUTION	0.0993	0.1018	0.1043
STORAGE	0.0110	0.0113	0.0116
SUBTOTAL RATE	0.1642	0.1679	0.1717
THROUGHPUT (Therms)	164,426	166,418	168,792
REVENUE	27,003	27,946	28,983
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	24,645	24,740	24,889
YEARLY TOTAL REVENUE	934,793	939,066	945,366

SIX YEAR TOTAL **GAS ACCORD**
SIX YEAR TOTAL BCAP (Table 2)

CORE COSTS: **GAS ACCORD**
COMPARED TO CURRENT RATES.
–1.21%

Discount Rate Equals 3% per year.

[*269]

DATA SOURCES FOR TABLE 1

	1997	1998	1999
RESIDENTIAL			
BACKBONE	W:18–11 F310	W:18–22 F261	W:18–34 F261
LOCAL TRANSMISSION	W:19–2 D751	W:19–3 D751	W:19–4 D751
CUSTOMER CLASS CHARGE	W:20–2 D194	W:20–11 D194	W:20–19 D194
DISTRIBUTION	W:22–3 BE680	NO ESCAL	2.5% ESCAL
STORAGE	W:23–1 D621	W:23–2 D261	W:23–3 D621
SMALL COMMERCIAL			
BACKBONE	W:18–11 F310	W:18–22 F261	W:18–34 F261
LOCAL TRANSMISSION	W:19–2 D751	W:19–3 D751	W:19–4 D751
CUSTOMER CLASS CHARGE	W:20–2 E194	W:20–11 E194	W:20–19 E194
DISTRIBUTION	W:22–3 BF680	NO ESCAL	2.5% ESCAL
STORAGE	W:23–1 E621	W:23–2 E261	W:23–3 E621
LARGE COMMERCIAL			
BACKBONE	W:18–11 F310	W:18–22 F261	W:18–34 F261

DATA SOURCES FOR TABLE 1

	1997	1998	1999
LOCAL TRANSMISSION	W:19–2 D751	W:19–3 D751	W:19–4 D751
CUSTOMER CLASS CHARGE	W:20–2 F194	W:20–11 F194	W:20–19 F194
DISTRIBUTION	W:22–3 BG680	NO ESCAL	2.5% ESCAL
STORAGE	W:23–1 F621	W:23–2 F261	W:23–3 F621

DATA SOURCES FOR TABLE 1

	2000	2001	2002
RESIDENTIAL			
BACKBONE	W:18–46 F261	W:18–58 F261	W:18–70 F261
LOCAL TRANSMISSION	W:19–5 D751	W:19–6 D751	W:19–7 D751
CUSTOMER CLASS CHARGE	W:20–28 D194	W:20–37 D194	W:20–46 D194
DISTRIBUTION	2.5% ESCAL	2.5% ESCAL	2.5% ESCAL
STORAGE	W:23–4 D621	W:23–5 D621	W:23–6 D621
SMALL COMMERCIAL			
BACKBONE	W:18–46 F261	W:18–58 F261	W:18–70 F261
LOCAL TRANSMISSION	W:19–5 D751	W:19–6 D751	W:19–7 D751
CUSTOMER CLASS CHARGE	W:20–28 E194	W:20–37 E194	W:20–46 E194
DISTRIBUTION	2.5% ESCAL	2.5% ESCAL	2.5% ESCAL
STORAGE	W:23–4 E621	W:23–5 E261	W:23–6 E621
LARGE COMMERCIAL			
BACKBONE	W:18–46 F261	W:18–58 F261	W:18–70 F261
LOCAL TRANSMISSION	W:19–5 D751	W:19–6 D751	W:19–7 D751
CUSTOMER CLASS CHARGE	W:20–28 F194	W:20–37 F194	W:20–46 F194
DISTRIBUTION	2.5% ESCAL	2.5% ESCAL	2.5% ESCAL
STORAGE	W:23–4 F621	W:23–5 F261	W:23–6 F621

[*270]
All Throughputs horn Table 7 of this Appendix.
W. (chapter–page)(cell number), from Workpapers for the **Gas Accord** Settlement Agreement, August 20, 1996
As ordered in D.95–12–053, Distribution rate is not escalated for 1998. Escalation for 1998 is forcast at 2.5% per year.
Procurement costs and Interstate fees are not included in the analysis because they should not differ between Table 1 and Table 2.
To simplify the analysis, 1997 is evaluated as a full year rather than a partial year as proposed in the **Gas Accord.**

TABLE 2 – CORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
RESIDENTIAL			
BASE	0.3188	0.3188	0.3268
ITCS	0.0032	0.0032	
TCRM	0.0037		
GFCA	0.0151	0.0130	0.0129
OTHER TRANSP	0.0125	0.0011	0.0011
SUBTOTAL RATE	0.3534	0.3361	0.3408

TABLE 2 – CORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
THROUGHPUT (Therms)	2,096,289	2,113,979	2,131,333
REVENUE	740,849	710,515	726,382
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	740,849	689,199	683,452
SMALL COMMERCIAL			
BASE	0.3188	0.3188	0.3268
ITCS	0.0032	0.0032	
TCRM	0.0037		
GFCA	0.0151	0.0130	0.0129
OTHER TRANSP	0.01253	0.0063	0.0063
SUBTOTAL RATE	0.3534	0.3413	0.3460
THROUGHPUT (Therms)	789,183	795,843	802,376
REVENUE	278,905	271,624	277,631
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	278,905	263,475	261,223
LARGE COMMERCIAL			
BASE	0.1404	0.1404	0.1440
ITCS	0.0032	0.0032	
TCRM	0.0037		
GFCA	0.0151	0.0130	0.0129
OTHER TRANSP	0.0135	0.0048	0.0048
SUBTOTAL RATE	0.1760	0.1614	0.1617
THROUGHPUT (Therms)	159,899	161,248	162,572
REVENUE	28,141	26,026	26,280
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	28,141	25,245	24,727
YEARLY TOTAL REVENUE	1,047,895	977,919	969,402
SIX YEAR TOTAL BCAP	$ 5,824,019		

Discount Rate Equals 3% per year.

[*271]

TABLE 2 – CORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in therm, Revenue in $ 000)

	2000	2001	2002
RESIDENTIAL			
BASE	0.3350	0.3434	0.3519
ITCS			
TCRM			
GFCA			
OTHER TRANSP	0.0010	0.0010	0.0009
SUBTOTAL RATE	0.3360	0.3444	0.3528

TABLE 2 – CORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in therm, Revenue in $ 000)

	2000	2001	2002
THROUGHPUT (Therms)	2,155,645	2,181,761	2,212,882
REVENUE	724,256	751,302	780,793
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	661,009	665,122	670,493
SMALL COMMERCIAL			
BASE	0.3350	0.3434	0.3519
ITCS			
TCRM			
GFCA			
OTHER TRANSP	0.0063	0.0062	0.0062
SUBTOTAL RATE	0.3413	0.3496	0.3581
THROUGHPUT (Therms)	811,529	821,360	833,076
REVENUE	276,960	287,111	298,358
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	252,773	254,178	256,210
LARGE COMMERCIAL			
BASE	0.1475	0.1512	0.1550
ITCS			
TCRM			
GFCA			
OTHER TRANSP	0.0048	0.0048	0.0048
SUBTOTAL RATE	0.1523	0.1560	0.1598
THROUGHPUT (Therms)	164,426	166,418	168,792
REVENUE	25,050	25,968	26,976
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	22,863	22,989	23,165
YEARLY TOTAL REVENUE	936,645	942,289	949,868
SIX YEAR TOTAL BCAP			

Discount Rate Equals 3% per year.

TABLE 3 – NONCORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
DISTRIBUTION			
BACKBONE	0.0213	0.0233	0.0246
LOCAL TRANSMISSION	0.0131	0.0135	0.0138
CUSTOMER CLASS CHARGE	0.0207	0.0149	0.0122
DISTRIBUTION	0.0656	0.0656	0.0672
SUBTOTAL RATE	0.1207	0.1173	0.1178
THROUGHPUT (Therms)	446,136	461,644	473,640

TABLE 3 – NONCORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
REVENUE	53,849	54,128	55,804
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	53,849	52,504	52,506
TRANSMISSION			
BACKBONE	0.0213	0.0233	0.0246
LOCAL TRANSMISSION	0.0131	0.0135	0.0138
CUSTOMER CLASS CHARGE	0.0174	0.0127	0.0100
CUSTOMER ACCESS CHARGE	0.0029	0.0030	0.0031
SUBTOTAL RATE	0.0547	0.0524	0.0515
THROUGHPUT (Therms)	1,334,664	1,381,058	1,416,942
REVENUE	73,046	72,423	72,902
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	73,046	70,250	68,593
UEG			
BACKBONE	0.0203	0.0222	0.0228
LOCAL TRANSMISSION	0.0131	0.0135	0.0138
CUSTOMER CLASS CHARGE	0.0132	0.0093	0.0066
CUSTOMER ACCESS	0.0007	0.0007	0.0008
SUBTOTAL RATE	0.0474	0.0457	0.0440
THROUGHPUT (Therms)	1,893,300	1,853,100	1,876,060
REVENUE	89,667	84,742	82,472
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	89,667	82,200	77,598
YEARLY TOTAL REVENUE (NONCORE)			
TABLE 3	216,562	204,954	198,696
TABLE 4	50,396	48,971	47,624
TOTAL	266,958	253,925	246,320
SIX YEAR TOTAL **GAS ACCORD**		$ 1,498,705	
SIX YEAR TOTAL BCAP (Table 5)		$ 1,623,538	

Discount Rate Equals 3% per year.

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TABLE 3 – NONCORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
DISTRIBUTION			
BACKBONE	0.0248	0.0249	0.0249
LOCAL TRANSMISSION	0.0141	0.0145	0.0149
CUSTOMER CLASS CHARGE	0.0083	0.0084	0.0085
DISTRIBUTION	0.0689	0.0706	0.0724
SUBTOTAL RATE	0.1161	0.1184	0.1206
THROUGHPUT (Therms)	488,504	502,888	530,227
REVENUE	56,739	59,537	63,932

TABLE 3 – NONCORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	51,784	52,708	54,901
TRANSMISSION			
BACKBONE	0.0248	0.0249	0.0249
LOCAL TRANSMISSION	0.0141	0.0145	0.0149
CUSTOMER CLASS CHARGE	0.0061	0.0062	0.0062
CUSTOMER ACCESS CHARGE	0.0031	0.0032	0.0033
SUBTOTAL RATE	0.0482	0.0488	0.0493
THROUGHPUT (Therms)	1,461,411	1,504,442	1,586,229
REVENUE	70,396	73,372	78,153
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	64,249	64,955	67,113
UEG			
BACKBONE	0.0228	0.0231	0.0232
LOCAL TRANSMISSION	0.0141	0.0145	0.0149
CUSTOMER CLASS CHARGE	0.0039	0.0039	0.0039
CUSTOMER ACCESS	0.0008	0.0008	0.0008
SUBTOTAL RATE	0.0416	0.0423	0.0427
THROUGHPUT (Therms)	2,110,250	2,149,090	2,097,440
REVENUE	87,702	90,799	89,624
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	80,043	80,384	76,963
YEARLY TOTAL REVENUE (NONCORE)			
TABLE 3	196,076	198,047	198,977
TABLE 4	45,356	45,800	47,246
TOTAL	241,432	243,847	246,223

SIX YEAR TOTAL **GAS ACCORD** NONCORE COSTS: **GAS ACCORD**
SIX YEAR TOTAL BCAP (Table 5) COMPARED TO CURRENT RATES.
–7.69%

[*273]

TABLE 4 – NONCORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
COGENERATION			
BACKBONE	0.0213	0.0233	0.0246
LOCAL TRANSMISSION	0.0131	0.0135	0.0138
CUSTOMER CLASS CHARGE	0.0132	0.0093	0.0066
CUSTOMER ACCESS CHARGE	0.0007	0.0007	0.0008
SUBTOTAL RATE	0.0484	0.0468	0.0458
THROUGHPUT (Therms)	996,577	1,031,219	1,058,013
REVENUE	48,194	48,292	48,415
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	48,194	46,843	45,553

TABLE 4 – NONCORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
COALINGA			
BACKBONE	0.0213	0.0233	0.0246
LOCAL TRANSMISSION	0.0131	0.0135	0.0138
CUSTOMER CLASS CHARGE	0.0145	0.0100	0.0072
CUSTOMER ACCESS CHARGE	0.0050	0.0051	0.0053
SUBTOTAL RATE	0.0539	0.0519	0.0509
THROUGHPUT (Therms)	2,366	2,449	2,512
REVENUE	128	127	128
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	128	123	120
PALO ALTO			
BACKBONE	0.0213	0.0233	0.0246
LOCAL TRANSMISSION	0.0131	0.0135	0.0138
CUSTOMER CLASS CHARGE	0.0136	0.0094	0.0066
CUSTOMER ACCESS	0.0013	0.0013	0.0013
SUBTOTAL RATE	0.0493	0.0474	0.0464
THROUGHPUT (Therms)	42,116	43,580	44,713
REVENUE	2,074	2,067	2,072
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	2,074	2,005	1,950
YEARLY TOTAL REVENUE	50,396	48,971	47,624

Discount Rate Equals 3% per year.

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TABLE 4 – NONCORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
COGENERATION			
BACKBONE	0.0248	0.0249	0.0249
LOCAL TRANSMISSION	0.0141	0.0145	0.0149
CUSTOMER CLASS CHARGE	0.0039	0.0039	0.0039
CUSTOMER ACCESS CHARGE	0.0008	0.0008	0.0008
SUBTOTAL RATE	0.0436	0.0441	0.0444
THROUGHPUT (Therms)	1,091,217	1,123,348	1,184,417
REVENUE	47,533	49,483	52,624
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	43,382	43,807	45,190
COALINGA			
BACKBONE	0.0248	0.0249	0.0249
LOCAL TRANSMISSION	0.0141	0.0145	0.0149
CUSTOMER CLASS CHARGE	0.0045	0.0045	0.0045
CUSTOMER ACCESS CHARGE	0.0054	0.0055	0.0057

TABLE 4 – NONCORE RATES AND REVENUES: **GAS ACCORD**
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
SUBTOTAL RATE	0.0488	0.0494	0.0499
THROUGHPUT (Therms)	2,591	2,667	2,812
REVENUE	126	132	140
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	115	117	120
PALO ALTO			
BACKBONE	0.0248	0.0249	0.0249
LOCAL TRANSMISSION	0.0141	0.0145	0.0149
CUSTOMER CLASS CHARGE	0.0039	0.0039	0.0039
CUSTOMER ACCESS	0.0014	0.0014	0.0014
SUBTOTAL RATE	0.0442	0.0446	0.0450
THROUGHPUT (Therms)	46,116	47,474	50,055
REVENUE	2,036	2,119	2,254
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	1,858	1,876	1,936
YEARLY TOTAL REVENUE	45,356	45,800	47,246

Discount Rate Equals 3% per year.

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DATA SOURCES FOR TABLE 3 AND TABLE 4

	1997	1998	1999
DISTRIBUTION			
BACKBONE	W:18–11 G310	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–2 G751	W:19–3 G751	W:19–4 G751
CUSTOMER CLASS CHARGE	W:20–2 G194	W:20–11 G194	W:20–19 G194
DISTRIBUTION	W:22–3 BE680	NO ESCAL	2.5% ESCAL
STORAGE	W:23–1 D621	W:23–2 D261	W:23–3 D621
TRANSMISSION			
BACKBONE	W:18–11 G310	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–2 G751	W:19–3 G751	W:19–4 G751
CUSTOMER CLASS CHARGE	W:20–2 H194	W:20–11 H194	W:20–19 H194
CUSTOMER ACCESS	W:21–2 H666	W:21–3 H666	W:21–4 H666
STORAGE	W:23–1 E621	W:23–2 E261	W:23–3 E621
UEG			
BACKBONE	W:18–11 I310	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–2 G751	W:19–3 G751	W:19–4 G751
CUSTOMER CLASS CHARGE	W:20–2 I194	W:20–11 I194	W20–19 I194
CUSTOMER ACCESS	W:21–2 I666	W:21–3 I666	W:21–4 I666
STORAGE	W:23–1 F621	W:23–2 F261	W:23–3 F621

DATA SOURCES FOR TABLE 3 AND TABLE 4

	1997	1998	1999
COGENERATION			
BACKBONE	W:18–11 G310	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–2 G751	W:19–3 G751	W:19–4 G751
CUSTOMER CLASS CHARGE	W:20–2 J194	W:20–11 J194	W:20–19 J194
CUSTOMER ACCESS	W:21–2 J666	W:21–3 J666	W:21–4 J666
COALINGA			
BACKBONE	W:18–11 G310	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–2 G751	W:19–3 G751	W:19–4 G751
CUSTOMER CLASS CHARGE	W:20–2 M194	W:20–11 M194	W:20–19 M194
CUSTOMER ACCESS	W:21–2 M666	W:21–3 M666	W:21–4 M666
PALO ALTO			
BACKBONE	W:18–11 I310	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–2 G751	W:19–3 G751	W:19–4 G751
CUSTOMER CLASS CHARGE	W:20–2 O194	W:20–11 O194	W:20–19 O194
CUSTOMER ACCESS	W:21–2 O666	W: 21–3 O666	W:21–4 O666

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DATA SOURCES FOR TABLE 3 AND TABLE 4

	2000	2001	2002
DISTRIBUTION			
BACKBONE	CCD–3–5–1	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–5 G751	W:19–6 G751	W:19–7 G751
CUSTOMER CLASS CHARGE	W:20–28 G194	W:20–37 G194	W:20–46 G194
DISTRIBUTION	2.5% ESCAL	2.5% ESCAL	2.5% ESCAL
STORAGE	W:23–4 D621	W:23–5 D621	W:23–6 D621
TRANSMISSION			
BACKBONE	CCD–3–5–1	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–5 G751	W:19–6 G751	W:19–7 G751
CUSTOMER CLASS CHARGE	W:20–28 H194	W:20–37 H194	W:20–46 H194
CUSTOMER ACCESS	W:21–5 H666	W:21–6 H666	W:21–7 H666
STORAGE	W:23–4 E621	W:23–5 E261	W:23–6 E621
UEG			
BACKBONE	CCD–3–5–1	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–5 G751	W:19–6 G751	W:19–7 G751
CUSTOMER CLASS CHARGE	W:20–28 I194	W:20–37 I194	W:20–46 I194
CUSTOMER ACCESS	W:21–5 I666	W:21–6 I666	W.21–7 I666
STORAGE	W:23–4 F621	W:23–5 F261	W:23–6 F621

DATA SOURCES FOR TABLE 3 AND TABLE 4

	2000	2001	2002
COGENERATION			
BACKBONE	CCD–3–5–1	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–5 G751	W:19–6 G751	W:19–7 G751
CUSTOMER CLASS CHARGE	W:20–28 J194	W:20–37 J194	W:20–46 J194
CUSTOMER ACCESS	W:21–7 J666	W:21–5 J666	W:21–6 J666
COALINGA			
BACKBONE	CCD–3–5–1	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–5 G751	W:19–6 G751	W:19–7 G751
CUSTOMER CLASS CHARGE	W:20–28 M194	W:20–37 M194	W:20–46 M194
CUSTOMER ACCESS	W:21–5 M666	W:21–6 M666	W:21–7 M666
PALO ALTO			
BACKBONE	CCD–3–5–1	CCD–3–5–1	CCD–3–5–1
LOCAL TRANSMISSION	W:19–5 G751	W:19–6 G751	W:19–7 G751
CUSTOMER CLASS CHARGE	W:20–28 O194	W:20–37 O194	W:20–46 O194
CUSTOMER ACCESS	W:21–5 O666	W:21–6 O666	W:21–7 O666

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W: (chapter–page)(cell number), from Workpapers for the **Gas Accord** Settlement Agreement, August 20, 1996
CCD–3–5–1 is a data request response from PG&E to CPUC, Commission Advisory and Compliance Division, 10/11/96.
All Throughputs from Table 7 of this Appendix.
As ordered in D.95–12–053, Distribution rate is not escalated for 1998. Escalation for 1998 is forcast at 2.5% per year.
Procurement costs and Interstate fees are not included in the analysis because they should not differ between: (a) Table 3 and Table 4, and (b) Table 5 and Table 6.
To simplify the analysis, 1997 is evaluated as a full year rather than a partial year as proposed in the **Gas Accord.**

TABLE 5 – NONCORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
DISTRIBUTION			
BASE	0.0984	0.0984	0.1008
ITCS	0.0110	0.0100	
TCRM	0.0037		
GFCA	0.0054		
BCMA	0.0209	0.0209	
OTHER TRANSP	0.0089		
SUBTOTAL RATE	0.1483	0.1293	0.1008
THROUGHPUT (Therms)	446,136	461,644	473.640
REVENUE	66,179	59,673	47,752
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	66,179	57,883	44,930
TRANSMISSION			
BASE	0.0320	0.0320	0.0328

TABLE 5 – NONCORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
ITCS	0.0110	0.0100	
TCRM	0.0037		
GFCA	0.0054		
BCMA	0.0209	0.0209	
OTHER TRANSP	0.0078		
SUBTOTAL RATE	0.0808	0.0629	0.0328
THROUGHPUT (Therms)	1,334,664	1,381,058	1,416,942
REVENUE	107,864	86,829	46,432
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	107,864	84,224	43,688
UEG			
BASE	0.0223	0.0223	0.0229
ITCS	0.0110	0.0100	
TCRM	0.0037		
GFCA	0.0054		
BCMA	0.0209	0.0209	
OTHER TRANSP	0.0035		
SUBTOTAL RATE	0.0669	0.0532	0.0229
THROUGHPUT (Therms)	1,893,300	1,853,100	1,876,060
REVENUE	126,656	98,661	42,959
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	126,656	95,701	40,420
YEARLY TOTAL REVENUE (NONCORE)			
TABLE 5	300,698	237,808	129,038
TABLE 6	125,612	110,877	75,847
TOTAL	426,311	348,684	204,885
SIX YEAR TOTAL BCAP	$ 1,623,538		

Discount Rate Equals 3% per year.

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TABLE 5 – NONCORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
DISTRIBUTION			
BASE	0.1033	0.1059	0.1086
ITCS			
TCRM			
GFCA			
BCMA			
OTHER TRANSP			

TABLE 5 – NONCORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
SUBTOTAL RATE	0.1033	0.1059	0.1086
THROUGHPUT (Therms)	488,504	502,888	530,227
REVENUE	50,482	53,267	57,567
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	46,073	47,157	49,435
TRANSMISSION			
BASE	0.0336	0.0344	0.0353
ITCS			
TCRM			
GFCA			
BCMA			
OTHER TRANSP			
SUBTOTAL RATE	0.0336	0.0344	0.0353
THROUGHPUT (Therms)	1,461,411	1,504,442	1,586,229
REVENUE	49,087	51,795	55,976
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	44,800	45,854	48,069
UEG			
BASE	0.0235	0.0241	0.0247
ITCS			
TCRM			
GFCA			
BCMA			
OTHER TRANSP			
SUBTOTAL RATE	0.0235	0.0241	0.0247
THROUGHPUT (Therms)	2,110,250	2,149,090	2,097,440
REVENUE	49,530	51,702	51,721
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	45,204	45,772	44,415
YEARLY TOTAL REVENUE (NONCORE)			
TABLE 5	136,078	138,783	141,918
TABLE 6	76,322	75,295	75,262
TOTAL	212,400	214,077	217,181
SIX YEAR TOTAL BCAP $	1,623,538		

Discount Rate Equals 3% per year.

TABLE 6 – NONCORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
COGENERATION			
BASE	0.0232	0.0232	0.0237

TABLE 6 – NONCORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	1997	1998	1999
ITCS	0.0110	0.0100	
TCRM	0.0037		
GFCA	0.0054		
BCMA	0.0209	0.0209	
OTHER TRANSP	0.0035		
SUBTOTAL RATE	0.0677	0.0541	0.0237
THROUGHPUT (Therms)	996,577	1,031,219	1,058,013
REVENUE	67,475	55,739	25,105
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	67,475	54,066	23,622
COALINGA			
BASE	0.0583	0.0583	0.0598
ITCS	0.0110	0.0100	
TCRM	0.0037		
GFCA	0.0054		
BCMA	0.0209	0.0209	
OTHER TRANSP	0.0037		
SUBTOTAL RATE	0.1031	0.0892	0.0598
THROUGHPUT (Therms)	2,366	2,449	2,512
REVENUE	244	218	150
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	244	212	141
PALO ALTO			
BASE	0.0398	0.0398	0.0408
ITCS	0.0110	0.0100	
TCRM	0.0037		
GFCA	0.0054		
BCMA	0.0209	0.0209	
OTHER TRANSP	0.0035		
SUBTOTAL RATE	0.0843	0.0707	0.0408
THROUGHPUT (Therms)	42,116	43,580	44,713
REVENUE	3,551	3,081	1,824
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	3,551	2,988	1,716
EXPANSION (Line 401)			
RATE	0.0386	0.0386	0.0386
THROUGHPUT (Therms)	1,409,000	1,433,000	1,388,000
REVENUE	54,342	55,268	53,532
PRESENT VALUE FACTOR	1.0000	0.9700	0.9409
REVENUE IN 1997 $	54,342	53,610	50,369
YEARLY TOTAL REVENUE	125,612	110,877	75,847

Discount Rate Equals 3% per year.

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TABLE 6 – NONCORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
COGENERATION			
BASE	0.0243	0.0249	0.0256
ITCS			
TCRM			
GFCA			
BCMA			
OTHER TRANSP			
SUBTOTAL RATE	0.0243	0.0249	0.0256
THROUGHPUT (Therms)	1,091,217	1,123,348	1,184,417
REVENUE	26,541	28,005	30,266
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	24,223	24,793	25,990
COALINGA			
BASE	0.0613	0.0628	0.0644
ITCS			
TCRM			
GFCA			
BCMA			
OTHER TRANSP			
SUBTOTAL RATE	0.0613	0.0628	0.0644
THROUGHPUT (Therms)	2,591	2,667	2,812
REVENUE	159	167	181
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	145	148	155
PALO ALTO			
BASE	0.0418	0.0428	0.0439
ITCS			
TCRM			
GFCA			
BCMA			
OTHER TRANSP			
SUBTOTAL RATE	0.0418	0.0428	0.0439
THROUGHPUT (Therms)	46,116	47,474	50,055
REVENUE	1,928	2,034	2,198
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	1,759	1,801	1,888
EXPANSION (Line 401)			
RATE	0.0386	0.0386	0.0386
THROUGHPUT (Therms)	1,426,000	1,422,000	1,426,000
REVENUE	54,998	54,844	54,998
PRESENT VALUE FACTOR	0.9127	0.8853	0.8587
REVENUE IN 1997 $	50,195	48,553	47,229

TABLE 6 – NONCORE RATES AND REVENUES: BCAP D.95–12–053
(Rates in $ /therm, Revenue in $ 000)

	2000	2001	2002
YEARLY TOTAL REVENUE	76,322	75,295	75,262

Discount Rate Equals 3% per year.

[*280] **DATA SOURCES FOR TABLES 2, 5 AND 6**

1997 Revenue from D.95–12–053.

As ordered in D.95–12–053, Base Revenue is not escalated for 1998. Escalation for 1998 to 2002 is forcast at 2.5% per year.

ITCS from Table 8 of this Appendix.

BCMA from Table 9 of this Appendix.

All Throughput from Table 7 of this Appendix.

Procurement costs and Interstate fees are not included in the analysis because they should not differ between Table 1 and Table 2, or between: (a) Tables 3 and 4, and (b) Tables 5 and 6.

Expansion Rate is 20% discount off current As–Available rate (Tariff G–XA).

To simplify the analysis, 1997 is evaluated as a full year rather than a partial year as proposed in the **Gas Accord.**

TABLE 7 – PROJECTED THROUGHPUT 1997 TO 2002
THROUGHPUT FROM **GAS ACCORD** WORKPAPERS – CHAPTER 18

(In Therms)

	1997	1998	1999	2000	2001	2002
CORE	3,045,370	3,071,070	3,096,280	3,131,600	3,169,540	3,214,750
NONCORE	2,821,860	2,919,950	2,995,820	3,089,840	3,180,820	3,353,740
UEG	1,893,300	1,853,100	1,876,060	2,110,250	2,149,090	2,097,440
OFF–SYSTEM	963,240	963,240	963,240	965,870	963,240	963,240
PAGE	18–8	18–20	18–32	18–44	18–56	18–68

THROUGHPUT FROM PG&E BCAP DECISION 95–12–053 (Appendix D)

CLASS	RESID.	SM COM	LG COM	TOTAL CORE
THERMS	2,076,904	781,885	158,420	3,017,209
PERCENT	69%	26%	5%	100%

CLASS	DIST	TRANS	COGEN	COAL	PALO A.	TOTAL NON–CORE
THERMS	413,814	1,237,967	924,374	2,195	39,065	2,617,414
PERCENT	15.8%	47.3%	35.3%	0.1%	1.5%	100%

DISAGGREGATED CLASS THROUGHPUT (**GAS ACCORD** x BCAP PERCENTAGE)
(IN THERMS)

TABLE 7 – PROJECTED THROUGHPUT 1997 TO 2002
THROUGHPUT FROM **GAS ACCORD** WORKPAPERS – CHAPTER 18

(In Therms)

	1997	1998	1999	2000	2001	2002
	1997	1998	1999	2000	2001	2002
RESIDENTIAL	2,096,289	2,113,979	2,131,333	2,155,645	2,181,761	2,212,882
SM COMM	789,183	795,843	802,376	811,529	821,360	833,076
LG COMM	159,899	161,248	162,572	164,426	166,418	168,792
DISTRIBUTION	446,136	461,644	473,640	488,504	502,888	530,227
TRANSMISSION	1,334,664	1,381,058	1,416,942	1,461,411	1,504,442	1,586,229
COGEN	996,577	1,031,219	1,058,013	1,091,217	1,123,348	1,184,417
COALINGA	2,366	2,449	2,512	2,591	2,667	2,812
PALO ALTO	42,116	43,580	44,713	46,116	47,474	50,055

NONCORE AND UEG ON–SYSTEM THROUGHPUT ON EXPANSION (LINE 401)

	Dth/Day	Therm/yr	
LINE 400 CAPACITY		1057	3858050
CORE RESERVATION		609	2222850
AVAILABLE TO NONCORE		448	1635200

NONCORE AND UEG MALIN THROUGHPUT
(in Therms)

	1997	1998	1999	2000	2001	2002
TOTAL MALIN	3,044,000	3,068,000	3,023,000	3,061,000	3,057,000	3,061,000
LESS LINE 400	1,635,000	1,635,000	1,635,000	1,635,000	1,635,000	1,635,000
EXPANSION ONLY	1,409,000	1,433,000	1,388,000	1,426,000	1,422,000	1,426,000

TOTAL MALIN from PG&E response to CACD Data Request CCD–3–5,
Revenue/Avg Rate=Throughput.
LINE 400 CAPACITY stated in D.94–02–042. Appendix A, 1041.5
Mmcf/day x 1.015 = Dth/day.

[*281] **TABLE 8 – INTERSTATE TRANSITION COST SURCHARGE (ITCS)**

Decision 95–12–053 set ITCS amortization for the BCAP period at 1/2 the forecast balance.

Advice Letter 1932–G set the 1/2 balance at $19,572 Core and $99,269 Noncore.

ITCS ACCOUNT BALANCE AND PROPOSED RATE

	A	B	C	D	E	F	G
		(A x 2)	(B x .75)		(C – D)		(E / F)
			RECOVERY	1996 + 97	1998	1998	1998
	BCAP	TOTAL	75%	REVENUE	BALANCE	THROUGHPUT	RATE
CORE	19,572	39,144	29,358	19,643	9,715	3,071,070	0.0031634
NONCORE	99,269	198,538	148,904	101,392	47,512	4,773,050	0.0099541

ADOPTED ITCS RATE (D.95–12–043) AND PROJECTED REVENUE
THROUGHPUT 1996 + 97,,1996,1997,TOTAL,REVENUE

CORE						
0.00324		3,017,209	3,045,370	6,062,579	19,643	
NONCORE		0.01097	2,617,414	2,821,860	5,439,274	59,669

ADOPTED ITCS RATE (D.95-12-043) AND PROJECTED REVENUE
THROUGHPUT 1996 + 97,,1996,1997,TOTAL,REVENUE

UEG	0.01097	1,910,050	1,893,300	3,803,350	41,723
TOTAL NONCORE (Including UEG)				9,242,624	101,392

THROUGHPUT: 1996 Uses 1995 Throughput from BCAP D.95-12-053.
(In Therms) 1997 and 1998 from Table 7 of this Appendix.
Column C, 75% Recovery, Per Chapter 8.

TABLE 9 - BACKBONE CREDIT MEMORANDUM ACCOUNT (BCMA)
(All $ in 000s)

BCMA Balance	Dec-95	Monthly	1996 Mon.	96 balance	10/1/96
D.96-09-095	22,000	500	9	4,500	26,500

All BCMA allocated to Noncore because of the ITCS cap.

[*282]

BCMA BALANCE AND PROJECTED RATE

	A	B	C	D	E	F
		(A x .50)			(C+D)	(B / E)
		RECOVERY		THROUGHPUT (therms)		BCMA
	BALANCE	50%	1997	1998	TOTAL	RATE
CORE	0	0	3045370	3071070	6116440	0.0000
NONCORE	265000	198750	4715160	4773050	9488210	0.0209

Column B, 50% Recovery, Per Chapter 8.
1997 and 1998 Throughput from Table 7 of this Appendix.

APPENDIX D**ELEMENTS OF THE JOINT RECOMMENDATION**

General

— > Joint Recommendation Revised market structure effective January 1, 1998.

— > Transfers management of PG&E's gas procurement functions for core, core subscription and UEG to a neutral party, an "independent procurement officer" (IPO), with no interest in gas supplies or transmission assets serving California, to neutralize PG&E's conflicts of interest.

— > Retains Line 400 and 300 as utility owned, rate based assets. Line 401 is a separate stand-alone facility with its own rate base and revenue requirement.

— > Provides for intrastate brokering of capacity on Lines 300 and 400.

— > CPUC should issue proposed decisions in the ongoing cases (ITCS market issues and CPIM, et al), while considering the structural proposal [*283] in this Joint Recommendation.

Core/UEG Procurement

— > PG&E reserves specified capacity dedicated to the core portfolio and is prohibited from dedicating its Transwestern capacity to the core or UEG portfolio without the benefit of competition.

— > Core (traditional and core subscription) and UEG procurement will be administered by an independent procurement officer (IPO) that has no financial interest in gas supplies or pipeline capacity serving California.

— > In managing core capacity, the IPO will treat all costs of reserved core capacity as avoidable based on market value of the capacity, thus facilitating a comparison of purchases from the various supply basins.

— > The brokering of core PGT capacity shall be deemed to occur at 100% of the as–billed rate for purposes of comparing gas costs from Canada and the Southwest.

— > Core subscription service should be retained for those customers that seek to use it.

— > PG&E may request a proposed supply and capacity portfolio to meet its UEG gas requirements. The IPO shall fulfill that requirement through a neutral competitive process that does not guarantee the use of a shareholder asset to the disadvantage of electric [*284] or gas ratepayers.

Noncore Service

— > Noncore reserves capacity on Lines 300 and 400 not used by core. The embedded costs of Lines 300 and 400 will be included in bundled volumetric rates.

— > Access to line 400/401 capacity will be available based on payment by users at a "posted" price set by PG&E 7 days in advance of each month. Rate cannot be indexed to Southwest prices. Options for service determined by PG&E and can include longer term contracts. Maximum rate for 400/401 shall be subject to the as–billed rate cap of Line 401.

— > All noncore Line 400 capacity will be deemed "sold" before any on–system deliveries shall be attributable to Line 401. Off–system sales shall be attributed to Line 401.

— > Line 300 will be auctioned with no minimum bid, using the same service options that PG&E makes available at posted prices for Line 400/401 (e.g., annual with 75% take, etc). If Line 300 capacity is hoarded, those holding the unused capacity should be subject to payment of full cost of service rates.

Backbone Transmission System

— > Embedded costs of Lines 300, 400 and other original backbone facilities will remain bundled in an intrastate volumetric rate.

[*285] — > Noncore customers will receive the revenues generated by the brokering of capacity allocated to them on Lines 400 and 300.

— > The core and noncore will pay for their reserved backbone capacity based on the percentage that reservation represents of PG&E's total backbone capacity on Lines 300 and 400.

— > The rate charged to the noncore will be based upon a 95% load factor usage of their allocated capacity.

— > PG&E will be at risk for recovery of original system backbone transmission costs allocated to the noncore.

End–Use Priority and Receipt Point Capacity Allocation

— > The End–Use priority system shall remain intact without change.

— > On line 400/401, receipt point allocation shall be first to firm expansion shippers, followed by as–available shippers in order of highest price. For shippers paying same price, those committing for a longer term will receive priority. On line 300, priority will be based upon highest auction price paid. Among those paying the same price, those having a longer term commitment will have a higher priority.

— > Receipt point allocation shall be based upon a seasonal weighted average daily quantity. This will avoid the gaming done [*286] by those with high summer MDQ's and low winter usage. The weighting will be based upon weekday and weekend.APPENDIX EJuly 1, 1997

Commissioner Josiah Neeper
Commissioner Richard Bilas
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Commissioners:Re: A.92–12–043 et al., PG&E **Gas Accord** (Alternate Proposed Order)

The Consumer Services Division (CSD) is pleased to forward for your consideration an agreement reached between CSD and Pacific Gas & Electric Company (PG&E) regarding alleged Rule 1 violations which arose in this docket. CSD has investigated and addressed the alleged Rule 1 issues and has contacted PG&E and discussed procedural options and settlement concepts. We are pleased to have reached a timely and constructive settlement with PG&E. It is attached.

CSD is designated to assist the Commission with enforcement matters generally and addressing Rule 1 issues in particular. In such circumstances, Commission has good cause to waive or not apply the usual settlement rules in considering whether to adopt this particular agreement.

The agreement features acknowledgment from PG&E that it inadvertently did not provide copies of the McLeod [*287] memorandum to some parties, and that the company's testimony was not as clear as it could have been surrounding reasons for going forward with the expansion project. PG&E agrees to a payment of $850,000 for the General Fund, a program of ethics training for employees who regularly participate before the Commission, and to systematically address in proceedings the establishment of a repository of all parties' data requests and the utility's responses — this could mitigate chances of any party not knowing about other requests and information which could be of significance to some parties. These features, we believe, if adopted by the Commission, fairly put the Rule 1 issues behind us.

Sincerely,

Ira R. Alderson, Jr.
Assistant General Counsel
Attorney for the Consumer Services Division
(415) 703–2058

Attachment

cc: P. Gregory Conlon, PresidentJessie Knight, Jr., CommissionerHenry Duque, CommissionerAll Parties to A.92–12–043 et al.**SETTLEMENT AGREEMENT**

This Settlement Agreement (Agreement) resolves issues between the Consumer Services Division (CSD) and the Pacific Gas and Electric Company (PG&E) in connection with alleged violations of Rule 1 of the Commission's [*288] Rules of Practice and Procedure as asserted by parties in A.92–12–043 and related matters and generally identified at pages 30–33 in the revised Proposed Decision of ALJ Well Circulated on May 21, 1997 and pages 36–40 in the Alternate Order prepared by Commissioners Bilas and Neeper and circulated on June 12, 1997.

The CSD has not been a party to the proceedings, but has responsibility for enforcing Commission rules and regulations, including pursuing alleged violations of Rule 1. This Agreement will become effective and operative upon approval by the Commission. If such approval is not received, it shall be void and given no weight or consideration in further proceedings on the alleged misconduct by PG&E.

The parties to this Agreement agree as follows:

1) CSD has conducted an investigation of the conduct which has been alleged to constitute a potential violation of Rule 1 and is prepared to resolve this matter expeditiously.

2) PG&E hereby expresses the following: it regrets that it inadvertently did not provide. copies of the McLeod Memorandum to certain requesting parties in A.92-12-043 et al., and acknowledges that the information in the memorandum may have been deemed [*289] relevant by parties and the Commission. PG&E acknowledges that it could have provided clearer prepared testimony in the PG&E Expansion rate case proceeding on the degree to which contracts for firm shippers had been executed and could have provided information on the Altamont competition and the potential TransCanada payment. Without regard to whether this conduct constituted a Rule 1 violation, it has resulted in additional proceedings at the Commission on these topics and would have required further expenditure of Commission resources to further investigate and resolve. PG&E recognizes the burden this has placed and is placing on the Commission and Commission resources and regrets having contributed to the need for such additional proceedings.

3) In recognition of the foregoing and in order to resolve this matter now in a manner which appropriately recognizes the importance of adherence to the Commission's rules of conduct, PG&E will, within 30 days after any order approving this agreement becomes final, make a payment of $850,000 to the Commission to be remitted to the General Fund for the State of California. This payment shall not be recorded as an operating expense by PG&E [*290] for ratemaking purposes.

4) This agreement resolves all Commission issues regarding PG&E's alleged violations of Rule 1. This Agreement does not constitute, nor shall it be deemed to constitute, a finding, acknowledgment or admission that the alleged conduct in any way constituted a Rule 1 violation. It does not bind other parties or governmental entities in connection with the alleged underlying conduct.

5) Within 60 days from the issuance of a Commission decision adopting this Agreement, PG&E shall develop, in consultation with CSD and the Commission's Public Advisor, a professional responsibility and practice course for PG&E's professional-level employees who routinely practice before the Commission regarding the preparation and processing of discovery and prepared testimony. The course shall last at least hours, but no longer than 1 day and shall be conducted not later than March 31, 1998.

6) In the future PG&E will affirmatively address the need for establishment of discovery repositories in all scoping memos in new proceedings in which it is the applicant or respondent.

7) CSD and PG&E agree that each of them may revoke this Settlement Agreement if the Commission does [*291] not approve it in its entirety and with language, terms and conditions consistent with this Agreement.

This agreement is freely entered by PG&E and the CSD in the interests of advancing a resolution of the allegations so that no further expenditure of Commission resources is made on this matter and all issues surrounding A.92-12-043 et al. can be resolved in a timely manner. The parties agree to submit this agreement to the Commission and ask for expeditious approval. CSD agrees to send this Agreement to all parties of record following its execution by CSD and PG&E.

Executed at San Francisco, California:

William R. Schulte, Director
Consumer Services Division
July 1, 1997

Roger J. Peters, General Counsel
Pacific Gas and Electric Company
July 1, 1997