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Decision 91-07-042 July 24, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for authority among other things, to increase its rates and charges for electric and gas service. (Electric and Gas) (U 39 M)	Application 88-12-005 (Filed December 5, 1988)
And Related Matter.	I.89-03-033 (Filed March 22, 1989)

ORIGINAL

INTERIM OPINION

1. Summary of Decision

This decision denies approval of a "Settlement Agreement for PG&E Non-Firm Rate Proceeding" (Settlement), filed January 18, 1991 by several parties to the test year 1990 general rate case (GRC) of Pacific Gas and Electric Company (PG&E). Further evidentiary hearings on the prepared testimony of the parties will be convened.

2. Procedural Background

In Decision (D.) 89-12-057[1] the Commission ordered PG&E to submit a study and proposal on nonfirm electric rates. In addition, the assigned Administrative Law Judge (ALJ) was ordered to arrange for informal meetings or formal hearings, as necessary, to refine PG&E's nonfirm electric rate incentives, which are discounts below firm service rates in exchange for possible curtailment by PG&E or interruption due to system instability.

PG&E submitted its "Final Study and Report" at the end of June 1990. A prehearing conference was convened by ALJ James Weil on August 30, 1990. By ruling dated September 11, 1990 the ALJ

1 34 CPUC 2d 199, 440 (1989).

adopted a procedural schedule which called for prepared testimony and evidentiary hearings. The schedule anticipated revised rates effective May 1, 1991, in conjunction with revisions ordered separately in the "rate window" phase of this proceeding.

On January 11, 1991 several parties active in this phase of the proceeding filed a "Notice of Settlement Conference (Rule 51.1)." The parties are PG&E, the Commission's Division of Ratepayer Advocates (DRA), California Large Energy Consumers Association (CLECA), California Manufacturers Association (CMA), Industrial Users, Federal Executive Agencies (FEA), and Cogeneration Service Bureau (CSB). The settlement conference was scheduled for January 18, 1991.

On January 14, 1991 the evidentiary hearing on the prepared testimony was convened as scheduled. The procedural schedule was revised to allow filing of comments on the Settlement after the settlement conference. The new schedule called for: (1) filing of comments by February 4, 1991, (2) a ruling in response to the comments, (3) possible concurrent testimony on the Settlement due February 26, 1991, and (4) possible hearings beginning March 5, 1991.

At the January 14 hearing the ALJ polled the parties on the need to continue evidentiary hearings on the prepared testimony, given the possibility that the Settlement would be approved. If the Commission were to reject the Settlement and it became necessary to hear testimony on the merits of the nonfirm incentives, then deferring the scheduled hearings could compromise the May 1 revision date. Confronted with the choice between the risk of going ahead with hearings unnecessarily (if the Settlement is eventually approved) and the risk of missing the May 1 target (if the Settlement is rejected), the parties generally agreed to defer hearings on the prefiled testimony. CLECA, Industrial Users, CMA, and FEA chose to defer the hearings. PG&E and Toward Utility

Rate Normalization (TURN) did not oppose the deferral, and DRA had no opinion.

At the hearing the ALJ allowed limited oral direct testimony from PG&E, CLECA, and DRA to clarify the upcoming Settlement and to allow TURN in particular to better understand the Settlement terms. (Tr. 7329) No cross-examination was allowed. Further hearings on the prepared testimony were deferred indefinitely. All of the prepared testimony was received into evidence, subject to future cross-examination. The ALJ ordered the late filing of Exhibit 2019, a comparison exhibit showing the positions of the parties on the principal issues.

On January 18, 1991 the required settlement conference was held. Later that day the Settlement proponents filed their "Motion for Adoption of Settlement Agreement Regarding Pacific Gas & Electric Company's Nonfirm Electric Rate Program" (Motion) and attached Settlement,[2] along with Exhibit 2019. The proponents are PG&E, DRA, CLECA, CMA, Industrial Users, FEA, and CSB; i.e., all the active parties in this phase of the GRC except TURN. The Settlement purports to resolve all issues surrounding PG&E's nonfirm electric rate program.

On January 30, 1991 PG&E sent a letter to the ALJ, with copies to all parties, to provide a bill impact analysis of the Settlement. At about the same time CSB filed comments in support of the Settlement, explaining technical issues relevant to standby customers, most of whom are qualifying facilities. On February 4, 1991 TURN filed comments opposing the Settlement, but made no request for hearings on its terms.

On February 13, 1991 the ALJ issued a ruling canceling the previously scheduled testimony and evidentiary hearings on the

2 Reproduced in Appendix A to this decision.

Settlement. The ALJ concluded that the record is adequate for the Commission to decide whether to approve or reject the Settlement.

3. Settlement Terms

The proponents claim that the Settlement resolves two key issues regarding nonfirm rate incentives. First, what is the appropriate amount of the incentive during conditions of: (a) emergency curtailment, (b) customer acceptance of underfrequency relays (UFRs), and (c) economic curtailment? Second, what are the necessary terms and conditions of the nonfirm rate program, and how do these ensure that customers will curtail when asked, justifying the incentive amount?

3.1 Incentive Amount

The incentive for accepting nonfirm service would be $70 per kilowatt-year (kW-yr), effective May 1, 1991, for emergency curtailments. Incentives for UFRs would be terminated. Under economic curtailment, customers could voluntarily curtail in exchange for payments based on circumstances at the time.

3.2 Duration of the Settlement

The incentive would last until PG&E's next GRC, expected to be for test year 1993.

3.3 Revenue Allocation

Treatment of nonfirm incentives for revenue allocation purposes would continue under a "supply side" convention as adopted in D.89-12-057. This means that incentive amounts, as calculated from marginal costs, are not adjusted by the ratio of adopted revenue requirement to marginal cost revenues (the equal percentage of marginal cost, or EPMC, ratio).

3.4 Maximum Curtailment

Customer emergency curtailments would be limited to 30 per year, with an aggregate maximum duration of 100 hours per year.

3.5 Mandatory Curtailments

Mandatory curtailments called "pre-emergency curtailments" would be established. They would occur up to five times per year, with a minimum of six times in any continuous three-year period. Terms would differ slightly for UFR customers and customers under direct load control. The curtailments would be imposed near or during peak load periods. They are intended to ensure customer compliance during true emergency curtailments. The proponents believe that pre-emergency curtailments would eliminate "free riders" who do not intend to curtail or who believe actual emergency curtailments are unlikely, based on recent experience.

3.6 Other Terms

Nonfirm service would be by contract, with a three-year contract term and three-year notice to increase nonfirm loads. Penalties would vary with compliance history, up to a maximum of two times the adopted incentive amount in a single year. Other Settlement terms specify program phase-in, customer eligibility, rate design, standby service, direct control options, reporting requirements, etc.

4. Standard of Review

Rule 51.1(e) of the Commission's Rules of Practice and Procedure states:

> "The Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest."

In D.88-12-083[3], regarding PG&E's Diablo Canyon nuclear power plant, the Commission discussed approval of settlements. Subsequent Commission review of a Southern California Edison Company (Edison) attrition settlement[4] was based on that decision. In D.88-12-083 the Commission mentioned many factors

3 30 CPUC 2d 189, 221 (1988).

4 D.90-12-021, December 6, 1990.

that should be considered and balanced in approving a settlement. Among them:

> "The most important element in determining the fairness of a settlement is the relationship of the amount agreed upon to the risk of obtaining the desired result."

The desired results in the present application are the diverse original positions of the parties, including both the nonfirm incentive levels and the terms and conditions for nonfirm service.

In D.88-12-083 the Commission also considered standards used by courts in review of class action settlements:

> "The standard used by the courts in their review of proposed settlements is whether the class action settlement is fundamentally fair, adequate, and reasonable. (Officers for Justice v. Civil Service Commission of the City and County of San Francisco [9th Cir. 1982] 688 F. 2d [615, 625]."

> "In order to determine whether the settlement is fair, adequate, and reasonable, the court will balance various factors which may include some or all of the following: the risk, expense, complexity, and likely duration of further litigation; the amount offered in settlement; the extent to which discovery has been completed so that the opposing parties can gauge the strength and weakness of all parties; the stage of the proceedings; the experience and views of counsel; the presence of a governmental participant; and the reaction of the class members to the proposed settlement. (Officers for Justice v. Civil Service Commission of the City and County of San Francisco, supra, 688 F. 2d at p. 625)."

> "In addition, other factors to consider are whether the settlement negotiations were at arm's length and without collusion; whether the major issues are addressed in the settlement; whether segments of the class are treated differently in the settlement; and the adequacy of representation. (Parker v. Anderson, [5th Cir. 1982], 667 F. 2d [1204,1209]."

We will test the Settlement on nonfirm incentives against the principles set forth in D.88-12-083.

5. Positions of the Parties on the Settlement

5.1. Settlement Proponents

The Settlement proponents present seven arguments in support of Commission approval. First, the Settlement reaches a balanced agreement among parties who hold very diverse positions on complex issues. The proponents' testimony reaches markedly different conclusions about the proper incentive amount and the operation of the program. They have agreed on few matters of either fact and policy, but they have succeeded in agreeing on Settlement terms which they believe balance their own various interests and those of PG&E's ratepayers.

Second, the Settlement was negotiated by parties who are knowledgeable and experienced in the complex issues regarding nonfirm rates.

Third, the settled incentive amount is less than PG&E's incentive levels in recent years but greater than the amounts recommended by PG&E and TURN.

Fourth, the Settlement program conditions will "weed out" present nonfirm rate customers who joined because they never expected to be curtailed or who would find it difficult to comply with program conditions.

Fifth, the Settlement will slightly reduce the total dollar impact of incentives on other customers.

Sixth, the Settlement program is reasonable on a relative basis. The incentive amount and the likely number of curtailments are "in the ballpark" when compared with those of other U.S. utilities.

Finally, approval of the Settlement would avoid extensive litigation of the many issues surrounding PG&E's nonfirm rates.

5.2 TURN

TURN believes that PG&E's present incentives are unreasonable because their terms and conditions do not ensure that nonfirm customers will curtail when asked, and the incentive amounts exceed the value of reduced demand to other customers. According to TURN, PG&E's current excess capacity and increasing customer participation suggest that many customers are free riders who do not intend to curtail when necessary.

TURN agrees with the proponents that a nonfirm rate program should continue, in order to give customers a consistent message that interruptibility has value to PG&E. However, the program must be effective and correctly priced.

TURN's major objection to the Settlement is that the incentive amount of $70/kW-yr is too high. TURN argues that the amount should be less than PG&E's adopted marginal generation cost of $56.17/kW-yr. The generation component of the incentive should be reduced by the Energy Reliability Index (ERI), which the Commission uses to adjust qualifying facility prices. TURN supports PG&E's position that there should be no transmission and distribution (T&D) component in the incentive because nonfirm customers do not avoid any T&D costs.

According to TURN, PG&E recommends very low incentive amounts in its testimony but has agreed to the Settlement because it is settling with someone else's money. The Electric Revenue Adjustment Mechanism (ERAM) guarantees that other customers, not PG&E, will make up any revenues lost through nonfirm rate incentives.

6. Discussion

6.1 Is the incentive amount in the Settlement fair and reasonable in relation to the risks of obtaining the parties' desired results?

There are two relevant issues here. First, is the level of the incentive (in $/kW-yr), considered in conjunction with the

Settlement terms and conditions for nonfirm service, fair and reasonable compared to the positions of the parties? Second, are the impacts of the entire program fair and reasonable to other customer classes?

TURN has not challenged the terms and conditions in the Settlement. The served testimony on incentive amounts is summarized in the comparison exhibit (Exhibit 2019) ordered by the ALJ. The lowest recommended incentive is $22.47/kW-yr, supported by TURN. The highest incentive is $102.77/kW-yr, recommended by FEA for primary and secondary voltage service. PG&E's testimony recommends $26.44/kW-yr for all voltage levels. DRA recommends $71.16/kW-yr for transmission voltage service and $92.45/kW-yr for lower voltages.

The wide range of incentive amounts in the testimony makes it difficult to assess the risks of going to hearing. The Settlement amount is close to the amounts recommended by DRA, but it is about three times the amounts recommended by PG&E and TURN. If TURN and PG&E were to prevail on the substantive issues of adjustment for ERI and exclusion of T&D costs, then the Settlement incentive amount would be too high. Correspondingly, if the nonfirm customers were to prevail on these and other issues, then the Settlement incentive amount would be too low, but not by a factor of three.

TURN's arguments point out the "zero sum" element inherent in adopting nonfirm incentives. Discounts granted to nonfirm customers must eventually be recovered from other customers. Residential and small commercial customers will bear much of that burden. We must take seriously the allegation that PG&E is settling with someone else's money. At least in the short run PG&E's shareholders are indifferent to the incentive amount.

If the incentive amount of $70/kW-yr were approved, residential and small commercial customers might be relieved of some revenue responsibility by the other terms of the Settlement.

If the penalty terms and mandatory curtailments did effectively remove free riders from the program, small customers would be helped by the Settlement. Unfortunately, the evidence on the record contains only estimates which assume no reduction in program subscribers.

In that light, and considering the testimony on the ERI and T&D issues, the Settlement proponents have not convinced us that the risks of going to hearing are fairly balanced against the settled incentive amount and the Settlement terms and conditions. Even considering the benefits of the Settlement terms and conditions, the risk that $70/kW-yr would exceed the amount adopted after hearings is too high.

6.2 What are other favorable elements of the Settlement?

We agree with the proponents that the Settlement was negotiated by knowledgeable and experienced parties, and that it would (at least slightly) reduce the impacts of the incentives on other customers. Completion of discovery in this phase of the GRC and DRA's participation also favor the Settlement. The Settlement would avoid contentious litigation, but that effect would not endure, as discussed below.

6.3 What are other unfavorable elements of the Settlement?

Distinct from the merits of TURN's economic arguments, the negative reaction from the small customer classes also weighs against the Settlement.

The Settlement would resolve PG&E's incentives through May of 1993, but the economic and policy issues in the determination of incentive amounts and program terms would only be deferred. Nonfirm rate incentives are an issue in Phase 2 of

Edison's current GRC.[5] Policy issues deferred by the Settlement will soon arrive in that proceeding, and further testimony by many of the proponents will be necessary. (We are optimistic that the Settlement negotiations in this proceeding will help sharpen the issues in the Edison GRC, whether the Settlement is approved or not.) The Settlement would balance the interests of many of the parties, but it would not "refine" PG&E's incentives in the sense of resolving basic issues.

6.4 Is the Settlement consistent with law?

The proponents have followed Rule 51 in presenting the Settlement to the Commission, and their arguments squarely address the factors in the standard of review. Consistency with law turns only on whether the Settlement is fundamentally fair and reasonable.

6.5 Is the Settlement fair and reasonable in light of the whole record?

We are not convinced by the evidence and arguments before us that the Settlement is fair and reasonable. We do not object to the terms and conditions of the proposed incentive program, but we cannot conclude that the incentive amount, even considering the benefits of the Settlement terms and conditions, is fairly balanced against the risks of going to hearing on the merits of the parties' testimony. The record may eventually show that incentive amounts either lower or higher than the proposed $70/kW-yr are reasonable, but from our present perspective we cannot accept the risk that $70/kW-yr is too high. Further hearings are necessary.

6.6 What issues should be addressed in further hearings?

This lengthy proceeding has brought into focus the issues involved in adopting a nonfirm rate program for PG&E's customers.

5 Application (A.) 90-12-018 and related matters.

Policy choices for PG&E will guide the Commission in future proceedings. Our goal is to resolve these issues expeditiously. The fundamental issues are:

1. Should nonfirm incentives be based on avoided costs? If so, the details of avoided cost calculations may need refinement. For example, what is the forecast horizon for the ERI, if adjustment for ERI is ordered?

2. Should the "supply side" convention, which requires no adjustment of avoided costs by the EPMC ratio, be continued?

3. Should avoided generation costs be adjusted for the ERI, and if so how?

4. Should incentive amounts include T&D costs?

5. Do system planners adequately consider nonfirm loads?

6. Should incentive amounts be reduced to reflect curtailment limitations?

7. Should penalties for noncompliance with curtailments be assessed to classes of customers (e.g., by reduced incentive amounts based on compliance expectations) or to individual customers (e.g., through direct penalties)? What are appropriate penalties?

8. Should the UFR program be continued, and if so at what incentive amount?

9. What mandatory curtailments are reasonable?

10. Should authorization for economic curtailment, based on PG&E's daily or hourly cost of service, be continued?

11. What other terms and conditions are reasonable (contract duration, minimum number of mandatory curtailments, rate design, standby service, amnesty periods, etc.)?

12. What is a reasonable incentive amount, reflecting a fair balance with program terms and conditions?

7. Comments on Proposed Decision

Pursuant to Public Utilities Code § 311(d) and Rule 77.1 of the Commission's Rules of Practice and Procedure, on June 5, 1991 the ALJ's proposed decision in this matter was filed with the Docket Office and mailed to all parties of record.

Comments on the proposed decision were filed by PG&E, DRA, CLECA, CMA, Industrial Users, and FEA. Reply comments were filed by PG&E and TURN.

All of the commenting parties except TURN argue that the proposed decision overemphasizes the amount of the nonfirm incentive, without considering the terms and conditions of nonfirm service contained in the Settlement. TURN's response to this charge is that only the level of the incentive was challenged. We have revised the proposed decision where appropriate to clarify the scope of our deliberations. The Settlement fails the standard of review when all of its elements are considered together, contrary to the allegations of the Settlement proponents that only the incentive level was considered.

In their comments, DRA and CLECA proposed that if the Settlement is rejected, further consideration of nonfirm rate incentives should be deferred to PG&E's next GRC. PG&E and TURN oppose that suggestion. We will not defer nonfirm rate issues to the next GRC. We will order further hearings on the testimony already prepared and on the record, as the ALJ has proposed.

Having reviewed these and the other comments of the parties, we conclude that the ALJ's proposed order should not be changed. The text of the proposed decision has been revised to clarify the reasoning behind rejection of the Settlement.

<u>Findings of Fact</u>

1. The purpose of this phase of PG&E's GRC is to refine PG&E's nonfirm electric rate incentives.

2. Nonfirm rate incentives are discounts below firm service rates in exchange for allowing curtailment by the utility.

3. On January 18, 1991 PG&E, DRA, CLECA, CMA, Industrial Users, FEA, and CSB filed a motion to adopt the Settlement.

4. TURN filed timely comments opposing the Settlement.

5. At hearing on January 14, 1991 no party opposed deferring the scheduled evidentiary hearings on the merits of nonfirm incentives, in order that the Commission could first consider the Settlement.

6. The record does not show that the incentive amount proposed in the Settlement, even considering the benefits of the Settlement terms and conditions of service, is fair and reasonable in relation to the risks to the parties of obtaining their desired results after further hearings.

7. The incentives established by the Settlement would have slightly less overall revenue requirement impact on other customers than those presently authorized.

8. Negotiations by knowledgeable and experienced parties, completion of discovery, and participation of the DRA favor approval of the Settlement.

9. Opposition by TURN, which represents residential and small commercial customers, and deferral of substantial issues weigh against approval of the Settlement.

10. The Settlement is not fair and reasonable in light of the whole record.

11. Further hearings are necessary to resolve the issues listed in Section 6.6 of this decision.

Conclusions of Law

1. PG&E's "Final Study and Report" satisfies the requirements of ordering paragraph 28 of D.89-12-057.

2. Excepting Rule 51.1(e), the motion of the Settlement proponents is in compliance with Rule 51 of the Commission's Rules of Practice and Procedure.

3. The record is adequate to decide whether to approve or reject the Settlement.

4. The Settlement should not be approved.

5. This order should become effective on the date signed because further hearings should be scheduled promptly.

INTERIM ORDER

THEREFORE, IT IS ORDERED that:

1. The "Motion for Adoption of Settlement Agreement Regarding Pacific Gas & Electric Company Non-firm Electric Program," filed January 18, 1991, is denied.

2. A prehearing conference shall be held in San Francisco in the Commission Courtroom on August 14, 1991, at 10 a.m., at which time the assigned Administrative Law Judge shall schedule further hearings on the previously served testimony in this matter, in furtherance of the Commission's goal of placing a nonfirm rate program in effect expeditiously.

This order is effective today.

Dated July 24, 1991, at San Francisco, California.

PATRICIA M. ECKERT
President
G. MITCHELL WILK
JOHN B. OHANIAN
DANIEL Wm. FESSLER
NORMAN D. SHUMWAY
Commissioners

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

Neal J. Shulman
NEAL J. SHULMAN, Executive Director
PG

EXHIBIT 1

SETTLEMENT AGREEMENT FOR PG&E NON-FIRM RATE PROCEEDING

The parties signing this settlement agree to the following terms for PG&E's non-firm rate program, to be effective May 1, 1991:

1. Incentive for non-firm service to be $70/kW-yr for emergency curtailment, with no additional incentive for UFR.

2. Incentive to apply until new rates go into effect as adopted pursuant to revenue allocation and rate design decision in PG&E's next General Rate Case ("GRC") (expected to be Test Year 1993); parties agree to work in the next GRC toward an incentive structure that fully considers rate stability for participating customers.

3. Treatment of non-firm incentives for revenue allocation purposes based on supply-side revenue allocation as adopted in Decision 89-12-057.

4. The rate design for non-firm customers to be adopted is shown in the attached Table 1. The principles on which the rate credits shown in Table 1 are based are as described in DRA's prepared direct testimony (and errata) in this proceeding.

The proposed credits by rate component are to be maintained until PG&E's next GRC decision.

5. Reporting requirements to be filed in annual ECAC reports as agreed to by PG&E and DRA as follows (subject to final agreement between PG&E and DRA):

a. Detailed accounting information on PG&E's California Power Pool transactions, and any other power purchases contracted for on an emergency basis. PG&E will provide this information in a format acceptable to DRA, as consistent as is practical with the description given in Appendix 1 of DRA's "Prepared Direct Testimony of James Price on PG&E's Non-firm Rates."

b. Daily operations reports for PG&E's summer operations period (June 1 to September 30), in the same format as was provided in Attachments 4-1 and 4-2 of PG&E's response to the CLECA data request in this proceeding. Additional information on specific operating days of interest to DRA will be provided upon request. Such information would consist of brief narrative reports that would either describe how any forecasted spinning reserve deficiency had been remedied (or why no remedial action was determined to be necessary), or note the fact that a curtailment had been called on the day in question.

6. Program operations criteria to be as follows:

a. Emergency operation up to 30 times per year (maximum 100 hours) according to the current operating criteria, as they are defined on the first page of the document entitled "Operation of Load Management Programs" (dated May 13, 1988, and as updated in the future, provided as Attachment 2 to PG&E's Final Study and Proposal filed in this proceeding). PG&E will continue its established practice of continually monitoring system conditions on critical operations days, based on the most current available forecasts of loads and resources.

b. Pre-emergency operation up to five times per year (with a minimum number of six pre-emergency operations in any rolling 3-year period). (Maximum of five hours per operation). These operations will be scheduled subject to the criteria described below. Non-firm customers electing to take service either on UFRs or under the direct control of PG&E (as described in Paragraph 9 of this agreement) will be subject only to up to three pre-emergency operations per year (with a minimum number of three pre-emergency operations in any rolling 3-year period). (Maximum of five hours per operation). The criteria used will be:

i. The 9:00 AM forecast of afternoon Central Valley temperature conditions (arithmetic average of forecasts for Sacramento and Fresno) is 100 degrees Fahrenheit or greater;

and,

Either PG&E's adjusted 10:00 AM forecast of two-hour reserves for that afternoon's peak is 12.0% or less, or the 10:00 AM forecast indicates that PG&E's afternoon peak will be within 500 MW of (or greater than) the previous record peak.

Or,

ii. The 9:00 AM forecast of afternoon Central Valley temperature conditions is that temperatures will be at least 105 degrees Fahrenheit.

Or,

iii. PG&E anticipates making discretionary emergency purchases at a price (inclusive only of all variable components of the price) greater than the tariffed E-20 Secondary non-firm on-peak energy rate.

APPENDIX A
Page 3

c. No pre-emergency curtailments for any non-firm customers will be called if there have been two or more emergency curtailments to date during the year, unless required to meet the condition of the 3-year minimum operations target. Similarly, no pre-emergency curtailments for any non-firm customers will be called if there have been two or more pre-emergency curtailments and at least one emergency curtailment to date during the year, unless required to meet the condition of the 3-year minimum.

7. Terms and conditions of non-firm service will remain as they are defined in the present tariffs, except as noted below (and also in Paragraphs 6, above, and 8 and 9, below):

a. PG&E permission or three years notice required to increase firm service level. PG&E permission will be waived on re-specifications of contracted firm service levels until November 1, 1991.

b. Term of contract: three years (no change from present tariff provisions).

c. Penalty provision: 50 percent of the adopted incentive at each instance of noncompliance ($7.00/kWh); this would be reduced to 25 percent ($3.50/kWh) if a customer substantially complies with the pre-emergency and emergency curtailments for the preceding calendar year; maximum penalty equal to 200 percent of the adopted incentive in any one year; penalty to be applied on a per kWh basis.

d. Maximum of 30 emergency curtailments per year, 100 hours per year; minimum 30 minutes notice; PG&E will provide greater notice whenever possible.

e. Three-month amnesty period for customers wishing to switch to firm service beginning with the effective date of new rates in this proceeding.

f. Current eligibility requirements will continue in effect, except for those standby customers electing alternative eligibility rules, as described in Paragraph 8 below and as to be defined in the Schedule S tariff.

g. Present phase-in mechanism to remain in place until at least May 1, 1993. Present UFR customers must continue taking service under UFR option, except as specified in Paragraph 9 below to maintain eligibility for phase-in calculations based on 1989 E-19 and E-20 interruptible rate schedules.

8. Customers served on standby Schedule S will have the option of meeting the current eligibility requirements (500 kW average on-peak demand) and the terms and conditions described in paragraph 6 above, or they can elect to take nonfirm service

under the provisions described in this paragraph:

a. Standby customers may elect to be served, at their choice, under the conditions described in this paragraph 8 a-f. However, to be served under the terms of this paragraph, they must have an average on-peak demand of 500 kW which can be served either by PG&E, their generator, or a combination thereof.

b. Service to be billed under the appropriate E-19 or E-20 schedule: same rate credits as defined in Table 1.

c. On-peak rate limiter on non-firm schedules to be set at the tariffed non-firm on-peak kWh rate, plus 67% of the differential between the tariffed on-peak kWh rate and the on-peak rate limiter on the corresponding firm schedule.

d. Additional metering for this option may be required at the customer's expense. Specifically, time-of-day metering (mag tape or load profile recorder) will be required on the generator output or total plant load. This metering can be owned by the customer if allowed to be regularly tested by PG&E.

e. Every standby customer served under this paragraph will be required to participate in all program operations called by PG&E, under pre-emergency or emergency conditions. (Participation, for purposes of this paragraph, means the reduction of their load served by PG&E to their contracted firm service level.) In addition, each customer must demonstrate to PG&E's satisfaction that they can reduce all plant load to their contracted firm service level for a minimum of three (3) hours (including electricity that would normally be provided by their own generator) during a curtailment operation. This may be done during an emergency or pre-emergency curtailment or at a time or manner that is agreed upon with PG&E. The minimum load drop during such a demonstration shall be 500 kW.

f. If a curtailment operation under paragraph e, above, occurs when the generator is operating, generator auxiliary station load (as specified and defined in the nonfirm service agreement) will be excluded.

9. Funding and implementation of remote metering and direct control will occur as described at pp. 33-36 of PG&E's prepared rebuttal testimony in this proceeding. Present UFR customers may retain phase-in eligibility based on 1989 E-19 and E-20 interruptible rates by transferring to direct control system, once this service option becomes available, provided that they either: (1) Agree to continue to be served under the direct control option for a term of at least three years, or (2) Reimburse PG&E for all expenses associated with the purchase and installation of all additional metering and control equipment

required by this service option, at the time the equipment is installed by PG&E.

10. In addition to the condition for pre-emergency curtailments based on avoidance of very expensive power purchases, the economic dispatch option adopted in Decision 89-12-057 will continue to be offered in the form of voluntary curtailments. Commission review of PG&E's decisions to offer such curtailments will recognize distinctions between energy and capacity payments made by PG&E for purchased power.

11. All parties signing this settlement agreement agree to sponsor and support the settlement agreement and its terms and conditions.

DATED: January 18, 1991

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TABLE 1

Summer on-peak demand:	\$4.90 per kW
Summer on-peak energy	2.414 cents per kWh
Summer pt-peak energy:	0.847 cents per kWh
All other TOU energy:	0.110 cents per kWh

Notes:

1) These credits are to be applied to the regular charges on each E-19, E-20 firm service schedule.

2) On-peak rate limiters are as defined in Paragraph 8(c) of Settlement Agreement.

(END OF APPENDIX A)