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Decision 82 12 120 December 30, 1982

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision 82-02-103 in Order Instituting Rulemaking No. 2.	Application 82-03-26 (Filed March 8, 1982)
SOUTHERN CALIFORNIA EDISON COMPANY, application for 3 standard offers for purchase of electric power from cogeneration and small power production facilities.	Application 82-03-37 (Filed March 8, 1982)
Application of SIERRA PACIFIC POWER COMPANY, for approval of its standard offer to purchase cogeneration and small power production facilities.	Application 82-03-62 (Filed March 16, 1982)
Application of PACIFIC POWER & LIGHT COMPANY for Approval of Certain Standard Offers Pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-03-67 (Filed March 18, 1982)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for an Order by the California Public Utilities Commission Directing SDG&E to Purchase Power From Qualifying Facilities Based on Standard Offers and to Make Certain Changes or Additions to its Tariffs Affecting Purchases from Qualifying Facilities.	Application 82-03-78 (Filed March 22, 1982)

Application of CP NATIONAL CORPORATION for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-04-21 (Filed April 8, 1982)
Rulemaking on the Commission's own motion to establish standards governing the prices, terms, and conditions of electric utility purchases of electric power from cogeneration and small power production facilities.	OIR 2 (Petition for Modifiction filed September 10, 1982)

(See Appendix A for appearances.)

I N D E X

O P I N I O N

Summary

Decision (D.) 82-01-103, January 21, 1982, established guidelines for utility purchases of electricity from cogenerators and small power producers. That decision ordered utilities to file five standard price offers each of which would be a complete contract which small power producers could sign without negotiation. The five offers were to meet the varied needs of different qualifying cogeneration and small power production facilities (QFs).

* The as-available offer pays an energy payment and a capacity payment in ¢/kWh varying by time of delivery. The payment is derived from utilities' short-run avoided costs (i.e., variable operating costs plus shortage value). This offer is similar to a spot market purchase in a competitive environment and requires no long-term contract-type commitment on the part of the QF.

* The firm capacity offer is like the as-available except that payments for capacity are based on specific performance requirements being met by the QF (including availability or output requirements). The capacity price may be fixed for up to 30 years. The offer provides some pricing certainty for those who can meet the specific performance criteria.

* The less than 100 kW offer is similar to the as-available, except for simplified requirements for the small facilities.

* The five-year forecast offer fixes energy prices for five years, providing more price certainty.

* The long-term resource plan based offer bases prices on new utility resources (as opposed to short-run avoided costs). It may be used to establish price more firmly for longer periods and to pay for the full value of new resources.

package, is found to be too burdensome and not in compliance with D.82-01-103. SDG&E's two offers are both found not to be in compliance. SDG&E is also directed to amend its offer consistent with PG&E's offer, as modified by the decision.

* Termination Provisions. In the event a firm contract QF terminates, the decision finds that the QF must repay the amount it was paid that exceeded what it would have been paid had it not signed a long-term contract (the levelization overpayment). Additional provisions are established if inadequate notice is given. This approach basically follows that used by PG&E and SDG&E. Edison's reimbursement calculation is approved, but Edison is otherwise required to modify its approach in keeping with the decision.

* Energy Payments. The decision establishes a procedure which allows QFs to review and comment on the utilities' proposed energy rates filed each period. It also orders the utilities to include contract language which clarifies that energy payments shall be derived from the full avoided variable operating costs throughout the life of the contract. Individual issues are also resolved regarding use of average vs. actual year incremental heat rates in the calculations (average is used now, but utilities can make proposals for actual later), line loss (such losses are assumed to be similar to utility plants, but further study is requested), and curtailment (the system established in D.82-01-103 is continued with a rejection of limits on the use of this provision for now).

The standard offer ordered by D.82-01-103 was intended to describe not only the prices to be paid to QFs, but the rights and obligations corresponding to those prices. The standard offer is, in other words, an economic package in which the prices and the contract terms are inextricably bound together.

In order to meet the varied needs of QFs, the standard offer, designed to recognize the two basic components of a power purchase - energy and capacity, provided five different options. The options, expressed as separate offers, were further distinguished by the time within which they were required to be filed by the utilities. A shorter time frame was assigned to those offers which we felt could be reviewed more expeditiously. The offers and filing periods were as follows:

1. Within 45 days of the effective date of D.82-01-103, the utilities were ordered to file standard offers for:

    a. As-available energy and capacity based on a short-run avoided cost methodology.

    b. Firm capacity based on a short-run marginal cost methodology.

    c. Energy and capacity provided by QFs below 100 kilowatts (kW) in size.

2. Within 90 days of the effective date of D.82-01-103, the utilities were ordered to file standard offers for:

    a. Energy based on a forecast of energy payments for up to five years tied to either an as-available or firm capacity option.

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The first three offers, as filed by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) are the subject of this decision. The utilities' standard contracts, as filed with the Commission, were reviewed during 40 days of compliance hearings in which the utilities, Commission staff (staff), and QFs participated. This decision responds to the various objections of the parties regarding pricing and standards for performance. It does not address all the issues raised in the proceeding. The remaining issues (interconnection, filing requirements, miscellaneous contract terms, insurance, and others) will be the subject of a later decision.

Given the policy of trying to create standard contracts which can be signed directly, the Commission reviewed all of the details relating to pricing and standard offer terms. The following is a summary of the specific issues addressed and resolved in this decision:

* <u>Payments for Capacity</u>. The decision adopts the full cost of a combustion turbine for capacity for long-term contracts signed at this time. It concludes that refinements to this methodology may be appropriate in the future.

* <u>Performance Requirements</u>. Regarding the specific performance requirements necessary to obtain firm capacity payments, the decision generally adopts PG&E's proposal which bases firm capacity on either <u>availability</u> (a QF agrees to produce when called upon) or <u>output</u> (a QF agrees to provide energy during 80% of a summer peak period). The QF has a choice. The proposal by Edison, on the other hand, is rejected, and the utility is asked to amend its offer consistent with PG&E's approach, as modified by this decision. Edison's proposal, by combining both availability and output in one

package, is found to be too burdensome and not in compliance with D.82-01-103. SDG&E's two offers are both found not to be in compliance. SDG&E is also directed to amend its offer consistent with PG&E's offer, as modified by the decision.

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Introduction

This decision represents a further step by this Commission toward its stated goal of promoting the development of cogeneration and small power production facilities, alternatives to the traditional generation of electric power through the use of fossil fuels. Our policy, developed in previous decisions, will be served by this order's clarification and further definition of the proper relationship between public utilities and these alternate generation resources.

To date, the most significant proceeding in this regard has been Order Instituting Rulemaking (OIR) 2. OIR 2 was commenced to establish standards governing the prices, terms, and conditions of utility purchases of power produced by qualifying cogeneration and small power production facilities (qualifying facilities or QFs). The proceeding was stimulated by our own independent action and analysis, as well as the requirements of both state law (Public Utilities (PU) Code § 2821) and federal law (the Public Utility Regulatory Policies Act of 1978 (PURPA)). PU Code § 2821 requires the Commission to "approve and establish equitable charges" to be paid to privately owned generation facilities. PURPA and the resulting regulations adopted by the Federal Energy Regulatory Commission (FERC) specify rules governing a public utility's purchase of power from cogenerators and small power producers who qualify for the benefits of the law. The FERC regulations require state implementation.

On January 21, 1982, we issued D.82-01-103 in OIR 2. The decision ordered the major California electric utilities to file standard offers for power purchases from qualifying facilities based on avoided cost principles. We concluded that avoided cost pricing would promote the maximum efficient development of these alternative resources.

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The standard offer ordered by D.82-01-103 was intended to describe not only the prices to be paid to QFs, but the rights and obligations corresponding to those prices. The standard offer is, in other words, an economic package in which the prices and the contract terms are inextricably bound together.

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    c. Energy and capacity provided by QFs below 100 kilowatts (kW) in size.

2. Within 90 days of the effective date of D.82-01-103, the utilities were ordered to file standard offers for:

    a. Energy based on a forecast of energy payments for up to five years tied to either an as-available or firm capacity option.

b. Firm capacity based on a utility's long-run marginal costs developed from the utility's resource plan.

The scope of the present proceeding is limited to those offers for which a 45-day filing was set in D.82-01-103, as listed under item 1. above. Five-year forecasted energy payments and long-term firm capacity offers will be reviewed in subsequent proceedings (Application (A.) 82-04-44, A.82-04-46, and A.82-04-47).

In D.82-01-103, the Commission outlined the procedure which would be followed in the approval of the offers filed after 45 days. Following staff review, the offers were to take effect two weeks after the date of filing unless otherwise suspended by the Commission. Each of these offers would then be reviewed in subsequent evidentiary hearings to determine the utility's compliance with D.82-01-103 and the factual basis for the prices contained in the offers. By D.82-04-071 (April 12, 1982), a subsequent order modifying D.82-01-103 and denying rehearing, all utilities were required to amend their initial filings to conform to the prescribed modifications and cure specific deficiencies identified in D.82-04-071. The presently effective offers were filed in May and July 1982.

Procedural Background

A. Prehearing Matters

Compliance hearings as required by the Commission in D.82-01-103 commenced with a prehearing conference held on May 10, 1982, in San Francisco, California. At that time, the presiding administrative law judge (ALJ) announced that at page 144 of D.82-01-103 the Commission had prescribed the scope of the hearings as follows:

"These evidentiary hearings...will be narrowly restricted to the issues of each utility's compliance with the requirements of this decision and of the factual basis for the prices contained in each standard offer. The evidentiary proceeding will not be a forum for reexamining the issues resolved in this decision." (Emphasis original.)

During the prehearing conference, however, it became clear that, even with this limitation on the hearings, there remained numerous issues related to both the utilities' compliance with D.82-01-103 and subjects not resolved by that decision but relevant to the standard offers. More than 25 parties voiced their concerns and offered suggestions with how to proceed in this complex matter.

Based on statements made at the prehearing conference and subsequent written statements filed by applicants and the staff on May 14, 1982, an ALJ ruling was issued on May 19, 1982. The ruling included the following determinations:

1. To initiate hearings, the completion of staff reports related to the applications of Edison (A.82-03-37), PG&E (A.82-03-26), and SDG&E (A.82-03-78) were necessary. Several of the applicant utilities had argued that their applications were intended to comply with the orders issued in OIR 2. Therefore the response of staff or interested parties to those filings were required in order to identify the issues.

2. Following receipt of staff's report on Edison, public hearings would commence on July 12, 1982, with Edison's direct showing.

3. Hearings on the applications of Sierra Pacific Power Company (A.82-03-62), Pacific Power & Light Company (A.82-03-67), and CP National Corporation (CP National) (A.82-04-21) would be deferred until staff reports could be issued on those applications.

4. The ALJ concurred with the staff that issues to be considered in this proceeding extended to questions dealing with provisions included in the utilities' applications, although not specifically addressed by the Commission in its OIR 2 decisions, as well as an applicant's compliance with those orders.

5. The tariffs required by D.82-01-103, Ordering Paragraphs 18 and 19 (standby rates) and Ordering Paragraph 21 (parallel generation), should be considered an integral part of the subject standard offers for purposes of assessing their compliance with OIR 2 and must therefore be made part of each of the subject applications.

B. Hearings

1. Expert Testimony

Following this ruling, 40 days of hearing were held between July 12, 1982 and October 15, 1982, in San Francisco. During that time. testimony was presented relating to the applications of PG&E, Edison, and SDG&E. Between the applicant utilities, the Alternate Generation and Rate Design Sections of the staff, state and local government agencies, and businesses and individuals presently or potentially operating or involved with cogeneration and small power production facilities, a total of 41 witnesses were called to testify. Many of these witnesses, who included experts in engineering, economics, law, and management, testified more than once during the hearings. Interested parties, representing various types of QF development, accounted for 17 of these witnesses. Seventy-four exhibits were received into evidence.

2. Statements

During the course of the proceeding, a number of individuals had expressed their desire to offer statements, as opposed to testimony. during hearing. In response to these requests, the ALJ, in noticing the hearing dates to be reserved for the testimony of interested parties, also set a specific date for public statements.

On August 30, 1982, 18 people offered their views relating to the standard offers at issue. These individuals were uniformly concerned that various provisions of the utilities' standard offers were not in keeping with this Commission's and PURPA's policy of encouraging the development of qualifying facilities. In particular, these individuals questioned the utilities' bases for the calculation of their avoided costs and the reasonableness of certain provisions of the standard offers which they considered to be penalties or obstacles to QF development.

Most of those making statements either were purchasers or sellers of small, home-sized (1 to 10 KW) wind generators. Their chief concern was the level of insurance required of QFs under the standard offers. It was argued that the premium level exceeded both the revenue benefit to be derived from installation of a wind generator as well as any risk created by such a facility. All agreed that the present insurance requirements would stifle the growing potential of this alternate resource.

In addition to these statements, other individuals either took the opportunity during other regularly scheduled hearing days to make statements or wrote letters to the Commission on the subject. These statements and correspondence, which were most frequently industry-specific, raised concerns similar to those expressed in other testimony and comments and asked the Commission to adopt standard offers which would encourage, not discourage, QF production.

C. Consideration of Firm Capacity Methodology

During the hearings PG&E and Edison attempted to offer testimony and question the staff on the proper methodology for determining the as-available capacity and firm capacity prices to be paid to QFs. By oral ALJ ruling on July 20, 1982, all parties were precluded from addressing this issue on the grounds that the issue had been resolved in OIR 2 and was beyond the scope of these compliance proceedings. This ruling was based on a review of the language of D.82-01-103 and D.82-04-071 in OIR 2 and consultation with the assigned Commissioner's office. On July 26, 1982 PG&E filed a motion with the Commission seeking reversal of this ruling. Edison filed a similar motion on July 29, 1982.

The assigned Commissioner concluded that this matter did not need to be referred to the Commission, but rather should be resolved by further ALJ ruling. Upon consideration of the petitions of PG&E and Edison and further review of the applicable Commission decisions, it was determined that the ALJ's ruling should be reversed in part and affirmed in part. Specifically, it was concluded that this proceeding was the proper forum for addressing the issue of the appropriate methodology for determining capacity costs, based on the shortage cost concept, under a utility's firm capacity standard offer. Revision of the methodology for calculating a utility's as-available capacity payment adopted in D.82-04-071, however, was reserved for the utilities' general rate cases as specified in that decision.

Testimony by all parties on the issue of the proper methodology for calculating a utility's firm capacity price was heard over a 10-day period following the presentation of all other testimony. In order to expedite the submission of this matter, certain information proposed by PG&E relating to this issue was directed to be served on the parties after the final day of hearing.

D. Submission

At the conclusion of the final day of hearing on October 15, 1981, and in an ALJ ruling issued that same date, A.82-03-26, A.82-03-37, and A.82-03-78 were submitted upon the following:

1. The submission by PG&E of an additional proposal and adjustment related to the Energy Reliability Index used by PG&E in calculating its shortage costs on which PG&E's standard offer for firm capacity will be based.

2. The filing of concurrent briefs on November 15, 1982.

PG&E was directed to serve its proposal on all appearances in this proceeding. Any party wishing to address or request a hearing on this proposal was directed to do so in the briefs due on November 15. Requests for hearing were to include a specific identification of the basis for the request and any questions to be addressed in cross-examination.

On the final day of hearing, SDG&E was also directed to furnish a copy of its input assumption data to staff, which had formally requested it on October 15, and to the State Energy Task Force, prior to the end of the briefing schedule. According to the briefs, this material had not been received by that time.

On October 25, 1982, PG&E filed its proposal. PG&E also submitted on November 2, 1982, a recalculation of its annual Energy Reliability Index adjustment factors based on a "low" load management scenario.

Between November 15 and 17, 1982, concurrent briefs were filed by a total of 16 parties including PG&E, Edison, SDG&E, staff, the Independent Energy Producers (IEP), the California Manufacturers Association (CMA), Occidental Geothermal, Inc. (Occidental), Ultrasystems, Inc., Federal Paper Board Company, Inc., the Regents of the University of California (UC), Calcogen, Inc., the California Energy Commission (CEC), the State Energy Task Force, the California Waste Management Board, Kimberly-Clark Corporation, and Simpson Paper Company. Any delays in filing were attributable to breakdowns in required support systems. Correspondence was also received at that time addressing issues similar to those presented in the briefs.

Positions of the Parties

The testimony received during hearing in this proceeding was sponsored by numerous witnesses representing a variety of interests, including those of the applicant utilities, government, and private industry. The views of 16 of the appearances regarding this record have been expressed in concurrent briefs. Other parties, although providing testimony, have chosen not to file briefs, in some cases apparently due to a lack of economic resources. Still others have addressed the issues raised during hearing in correspondence to the Commission. To provide an overall description of the parties' basic viewpoints, we have summarized the positions below.

A. Utilities

All three utilities, PG&E, Edison, and SDG&E, believe that their applications are in full compliance with this Commission's decisions in OIR 2. Each asserts that the record fully supports this conclusion.

The utilities are also of the opinion, however, that to promote the continued development of QF power, certain amendments to their standard offers may be desirable. Each utility asks that it be recognized that any suggested modifications of its standard offers do not result from a failure to comply with OIR 2, but rather are aimed at better achieving the goal of QF development.

According to their briefs, the determination or adoption of any standard offer amendment by a utility was greatly influenced by the utility's perceived responsibility to its ratepayers. The utilities believe that the PURPA mandate requiring prices paid for QF power to be just and reasonable to ratepayers is embraced in the concept of avoided cost. Under that concept, the utility is to pay the QF a price equal to the cost the utility would have incurred had it generated the electricity itself or purchased the power elsewhere. The ratepayer should therefore remain indifferent to whether the utility or the QF produces the power.

This principle of ratepayer indifference has led the utilities to conclude that a standard offer must result in a proper allocation between QFs and utilities of the risks associated with the transaction. Should business and economic risks be shifted to the utility and its ratepayers disproportionate with the benefits to be received from QF production, a ratepayer would no longer remain indifferent since that risk would ultimately be translated into additional costs to the ratepayer.

The utilities' briefs also reflect the view that the standard offer is a single, integrated economic package. SDG&E specifically advises that the division of issues in its brief is arbitrary since all of the standard offer provisions relate to price in one way or another.

B. Staff

The staff states that its primary concern is whether or not the utilities' standard offers comply with this Commission's decisions in OIR 2. Staff is of the opinion, however, that to develop effective standard offers the issue of compliance should include an examination of (1) the propriety of contract terms which the Commission has yet to direct be included or excluded from the standard offers, (2) the determination of a utility's true avoided costs, and (3) the need for standardization of contract terms between different utilities' standard offers.

Like the utilities, the staff's recommendations are intended to achieve the proper balance of ratepayer and QF interests. The risks associated with the standard offers, however, are viewed somewhat differently by the staff than by the utilities. In particular, the staff notes that the QF market is still in its infancy. This circumstance has two results - the need for continued encouragement for its development and an increase in the risks which potential investors and owners perceive are associated with a QF's operations. It is the staff's belief that ratepayers who will benefit from the increased development of alternate energy resources should share in the risks related to this emerging industry.

C. Private Industry

This category includes a total of eight parties representing the interests of currently operating or potential QFs. Among these parties were two associations: IEP, representing a group of California cogenerators, small power producers, and related businesses, and CMA, representing industries some of whom desire to participate in QF programs and other who do not. Briefs were also filed by Occidental, Ultrasystems, Inc., Federal Paper Board Company, Inc., Calcogen, and Kimberly-Clark Corporation and Simpson Paper Company, who sponsored a joint brief.

The participation of all of these parties has focused on challenges to either the utilities' compliance with OIR 2 or their proposed methodologies for calculating their firm capacity payments, an issue included within the scope of this proceeding. Influencing the positions taken by these parties has been their particular perception of the risks associated with the utility-QF transaction and the proper allocation of those risks. It is the opinion of the industry that to require the QF to bear certain of these risks will ultimately stifle the development which the Commission specifically sought to encourage in OIR 2.

According to these parties, among the risks facing QFs is the inability to obtain financing for projects and predict, on the basis of the contract terms, what each QF can expect in the future. These concerns have been heightened by a substantial drop in avoided cost payments to QFs. This circumstance has jeoparidzed the operations of current producers and the projects of potential QFs.

Because of this asserted instability in the industry, QFs in their testimony and briefs have been most concerned with the utilities' methods for calculating avoided costs, the availability of data to verify those calculations, the standards of performance required of QFs, the ambiguity and lack of standardization with respect to certain contract terms, and the utilities' assignment of particular risks to QFs, including the risk of future regulatory changes.

It is the view of the industry that QF production reduces the risks to which ratepayers would otherwise be exposed by utility operations. For this reason, it is the industry's position that QF development should not be stifled by the improper calculation of price, the absence of proper incentives, or a demand for performance which exceeds that of a utility's own plants.

D. State Government

Besides this Commission's staff, briefs were filed by four other state governmental entities: the CEC, the California Waste Management Board, the State Energy Task Force, and UC. With the exception of the CEC, each of these entities is involved directly in the development of alternate generation facilities.

The positions expressed by these parties have been formulated based on a strong desire for the continued encouragement of QF development and for the resolution of problems created by unique arrangements and resources in which the State, in certain cases, intends to be involved. With respect to this latter circumstance, this Commission has been asked to consider the special needs and benefits of projects converting solid waste into energy and the impact on the standard offer of the State itself being a party to or potential beneficiary of the agreement.

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Aside from these special concerns, the views of these state entities mirror those held by the QF industry. The utilities' avoided cost calculations are questioned, while standardization of and certainty in contract terms are urged. It is the opinion of state government that its recommendations take into consideration the appropriate allocation of risks between QFs and ratepayers.

B. Positions Expressed in Testimony or Correspondence

The participation of four of the interested parties to this proceeding was limited to the receipt of their testimony; no briefs were filed. These parties included the California Wind Energy Association (CalWEA), which indicated that its financial resources for participation were limited; American McGaw, a manufacturer owning a 2,800 kilowatt (kW) cogeneration facility in California; Henwood Associates, consultants negotiating contracts and arranging financing for QFs; and the County Sanitation Districts of Los Angeles County, the City of Commerce, and the City of Long Beach, local government entities with an interest in waste-to-energy projects.

The sole purpose of the two exhibits sponsored by CalWEA was to challenge the insurance requirements of the utilities' standard offers. Because of the high cost of such insurance and the documented safety of farm- and home-sized wind generators, CalWEA has urged the modification or elimination of the utilities' insurance provisions for wind systems of 20 kW or less. The testimony of the County Sanitation Districts expressed concerns regarding waste-to-energy projects similar to those contained in the testimony and brief of the California Waste Management Board. American-McGaw's testimony covered issues and expressed opinions comparable to those of other industry representatives. Henwood Associates focused on perceived shortcomings in Edison's standard offers.

At the time of submission of this matter, Helmich Engineering, United Energy Corporation, and Hudson Lumber Company wrote to this Commission indicating their views. Mr. James E. Helmich of Helmich Engineering is an appearance of record, while the latter two corporations are members of IEP. Price fluctuation, which in one case has directly affected operations, was the primary concern of these companies. Like other individuals who have written to the Commission during the course of these proceedings, a resolution of this matter before the end of 1982 was urged to ensure the continued development of the QF industry.

Scope of the Decision

Before commencing our discussion on the issues raised in this proceeding, we must first consider two requests made by several parties regarding the scope and timing of this decision. It is the view of the QF industry that for its development to continue (1) an order resolving all of the issues relating to the subject standard offers must be reached and (2) that order must be issued expeditiously, preferably before the end of 1982. The standard offer is seen as a single, unseverable economic package, the provisions of which must be known before a QF can commence or continue its operations.

Unfortunately, with the extensive participation and record in this matter, the earliest submission date for these applications was November 15, 1982. As a result, we have been left little time to prepare an order which would resolve all of the standard offer issues this year while simultaneously giving the proper weight and consideration to all of the views presented.

For this reason, although we recognize that the standard offer provisions are interrelated, we can address in this decision only certain of the issues arising from those offers. We believe, however, that the subjects chosen, i.e., the basic price issues and certain contract provisions, will provide sufficient options for QFs to make the economic decisions necessary for determining the merits of proceeding with or continuing a particular project.

By adopting this approach, we will be able to consider fully the record which the parties have spent appreciable time and effort developing. All appearances should be assured, however, that those issues which are not discussed in this order will be addressed as early as possible next year.

Specifically, this decision will examine the utilities' bases for and standard offer provisions relating to capacity payments and energy payments. Our discussion of capacity and energy payments will include consideration of such issues as performance requirements, termination, and periods of curtailment. We will also consider the propriety of providing for the conversion of standard offer contracts signed after the effective date of this order to the standard offers approved in our forthcoming second opinion in this proceeding.

Capacity Payments

Because this proceeding was primarily intended to determine the utilities' compliance with our decisions in OIR 2, a basic understanding of those orders, as related to each of the issues to be considered, is critical. With respect to payments for capacity, this Commission concluded in D.82-01-103 that energy delivered on either an as-available or firm basis resulted in a utility avoiding capacity costs. Avoided capacity costs are those costs associated with ensuring the reliability of the production and delivery of electricity which the utility avoids incurring by purchasing power from a qualifying facility.

In OIR 2, the utilities had questioned whether any capacity costs are avoided when energy is delivered to the utility only as it becomes available. D.82-01-103 recognized, however, that as-available power, when aggregated, did in fact result in a reduction in demand upon the utility and thereby avoided certain capacity costs, including those associated with generation and generation-related transmission. Payments for as-available power, however, would not reflect any value for contract length, notice, termination, or sanctions since such provisions would not be part of an as-available offer.

In contrast, firm capacity was viewed as an increase in the utility's supply of electricity with corresponding performance standards, termination provisions, and sanctions. By definition, firm power is provided in predetermined quantities at predetermined times with sufficient legally enforceable guarantees of deliverability to permit the purchasing utility to avoid the construction of a generating unit or the purchase of firm power elsewhere. A QF providing firm capacity, was determined to avoid costs additional to those related to as-available power. This result was to be reflected in the firm capacity payment.

With respect to the amount to be paid QFs for their output, D.82-01-103 requires "full avoided cost pricing of power from qualifying facilities." (Mimeo, at page 26.) For purchases of both firm and as-available capacity, PG&E, Edison, and SDG&E were directed to base their payments on each utility's estimate of its current shortage costs using a combustion turbine facility as a proxy.

Although recognizing that the combustion turbine was a somewhat less attractive methodology for firm, as opposed to as-available capacity, payments, we concluded in D.82-04-071 that revisions to the adopted methodology would only be considered in the future. For as-available capacity prices, consideration of such revisions was set for the utilities' general rate cases. No specific time, however, was identified for examining modifications of the methodology for calculating firm capacity payments. As stated previously, by ALJ ruling, the proper forum was found to be this proceeding.

Because the firm capacity payment should reflect certain factors not included in the as-available capacity price, the following discussion will commence with an examination of the utilities' standard offer terms governing performance and termination in a firm capacity contract. We will then review the methods by which the utilities have calculated the prices to be paid for both firm and as-available capacity.

A. Performance and Termination Provisions in Firm Capacity Contracts

Consistent with the applicable FERC regulations, D.82-01-103 states:

> "The firm capacity payment properly reflects the factors recited in Part IV,A, above related to the availability during system peak periods, including:

"a. Dispatchability,

"b. Reliability,

"c. Contract duration, termination, and sanctions,

"d. Scheduling of outages, and

"e. Availability during emergencies.

"The value of each of these factors shall be calculated, based on standards comparable to performance standards the utility would impose on its own plants. These standards must, however, be fair to QFs and not impose unnecessary burdens that will discourage the development of these preferred resources. The sum of each of these factors and the resultant capacity value will be offered on both a dollars per kW per year and a cents per kWh basis as currently done. A QF that exceeds operating standards normally expected of utility plants should be able to earn a higher capacity payment." (Mimeo, at page 57.)

To aid in the development of standard offers incorporating these basic principles, D.82-01-103 provided further definition of the factors to be reflected in the firm capacity payments. This amplification of each factor can be summarized as follows:

1. <u>Dispatchability</u>. According to D.82-01-103, dispatchability is achieved in standard offers by time basing capacity and energy prices and requiring QFs to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs are to be expected to operate at maximum capacity on notice requiring QFs to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs are to be expected to

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"b. Reliability,

"c. Contract duration, termination, and sanctions,

"d. Scheduling of outages, and

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operate at maximum capacity on notice to meet utility needs for capacity during peak load periods and emergencies consistent with resource limitations.

2. Reliability. Reasonable requirements for reliable operation and availability during utility system peak load periods are to be imposed in the standard offers. These requirements, however, should not be unduly restrictive or complicated or impose standards of reliability greater than the utility plants the QF displaces. When resource limitations exist to reliable operations, such as with wind parks, plant capacity factor may be a better measure of reliable operation.

3. Contract duration, termination, and sanctions. QFs should be provided the option for levelized capacity payments for periods up to 25 to 30 years. Other than general statements requiring fair contract requirements, the exact terms for provisions relating to termination and sanctions were not specified.

4. Scheduling of outages. A utility purchasing firm capacity from a QF may reasonably require the QF to schedule maintenance of that generation during periods established by the utility. The utility must provide reasonable periods for QF scheduled maintenance and only request deferments in the customer's requested maintenance schedule on 60 days' notice. Capacity payments must not be reduced during scheduled maintenance periods.

5. Availability during emergencies. A QF must be expected to operate at maximum capacity on notice to meet utility needs for capacity during emergencies.

Other than our recognition that plant capacity factor, as opposed to availability, might be a better measure of the reliable operation of certain technologies, D.82-01-103 did not endorse any special treatment for specific resources other than small hydro electric facilities. For hydro QFs larger than 100 kW, adjustments for dry year unavailability are to be made in determining the QF's base stream flow and monthly firm capacity rating. A hydro QF would be allowed to use either (1) flow data directly applicable to the QF's facility, when available, or (2) the flow data for the area closest and most similar to the QF's facility, using areas sufficiently limited in size so that the true value of local areas would not be lost or obscured. The minimum June through August flow, from which the monthly firm capacity rating was to be derived, would be based on the five lowest flow years taken from a 50-year minimum continuous record. If this data could not be developed, utilities and QFs would agree upon a shorter time period with fewer minimum flow years averaged into a monthly capacity rating. For both options, capacity values were to be paid in dollars per kW per month and otherwise subject to the requirements of a firm capacity sale.

In examining the utilities' compliance with the OIR 2 decisions, we will first consider the issues relating to all of the above factors, except for termination. A review of the utilities' proposed termination provisions will follow in a separate section.

1. Performance Requirements

A finding of compliance or noncompliance with the requirements of D.82-01-103 enumerated above requires an understanding of each of the utility's standard offer provisions relating to performance. Additionally, the positions of both utilities and interested parties must be considered.

a. PG&E Standard Offer No. 2,
Appendix C — Firm
Capacity Price Schedule

PG&E's standard offer provisions governing the conditions of firm capacity payments are set forth in Appendix C of its Standard Offer No. 2 (Firm Capacity and Energy Power Purchase Agreement). PG&E's minimum performance requirements are inextricably tied to the type of capacity payment chosen by the QF. These two payment options are described in Section C-5 of Appendix C.

Under Option 1 the monthly payment for capacity, paid in dollars per kW per month, is one-twelfth of the product of the designated per kW annual contract capacity price multiplied by the contract capacity (the amount of energy in kW to be sold and delivered) and by the appropriate loss adjustment factor. In order to receive these 12 equal monthly payments, the QF must meet performance standards which essentially make it dispatchable by PG&E. Specifically, PG&E requires the QF's contract capacity to be available (dispatchable by or delivered to PG&E) during all on-peak hours of the peak months of June, July, and August, subject to a 20% allowance for forced outages in any month. The contract capacity must also be dispatchable throughout the rest of the year subject to a 20% monthly allowance for forced outages and a designated allowance for scheduled maintenance. During these months other than the peak months, the QF may accumulate and apply the 20% forced outage allowance for any consecutive three-month period. Dispatchability is defined by PG&E as the QF being operable and capable of being called upon at anytime to deliver capacity at any level up to the full contract capacity. The QF must demonstrate that its facility is fueled by a reliable fuel supply and that adequate fuel storage is available to deliver power as requested by PG&E's system dispatcher.

Option 2 provides for payments to QFs, again in dollars per kW per month, for the amount of capacity actually delivered during peak and partial peak hours. A formula for calculating this payment is specified in Option 2 and includes a 20% forced outage allowance credit for each month. Although a QF electing Option 2 must deliver its full contract capacity to PG&E during the peak hours of the peak summer months subject to a 20% forced outage allowance, no other performance requirements are imposed for the rest of the year. During the summer peak months, the 20% forced outage limitation and the measurement of performance according to deliveries means that the QF must deliver the contract capacity at least 80% of the peak hours, thus achieving a peak period capacity factor of 80% during the summer months. During the rest of the year the QF is paid for capacity according to how much energy is delivered, but there is no specified performance level that must be met.

Under Option 1 the QF is dispatchable and has its performance judged according to its availability or ability to deliver whereas under Option 2 the QF is not dispatchable and has its performance judged according to its output or actual deliveries. Also, under Option 2 performance is only judged during the peak summer months whereas under Option 1 there are certain year-round requirements. Apart from these basic differences the remaining provisions of Appendix C are, for the most part, identical for both options. These provisions include a limitation on contract capacity price used to calculate QF payments under either option of 100% of PG&E's shortage costs.

Additionally, to qualify for firm capacity payments, outages for scheduled maintenance (i) cannot occur within the first six months of operation, (ii) cannot occur between May and October unless otherwise agreed to in writing with PG&E, (iii) cannot be undertaken without six months' prior written notice to PG&E's system dispatcher, and (iv) cannot exceed a total of 35 days in any 12-month period. Both options permit capacity payments to continue during the period allowed for such scheduled maintenance.

Section C-3 of Appendix C governs failures to meet the minimum performance requirements. Essentially, this section applies (i) if an Option 1 QF fails to have at least 80% of its contract capacity available during the peak hours of the peak summer months or the allowable percentage, taking into account properly accumulated allowances for forced outages in other nonpeak months or (ii) if an Option 2 QF fails to deliver at least 80% of its contract capacity during the peak hours of any of the peak months. If the reason for this failure is other than a forced outage or force majeure, PG&E may immediately suspend the payment of capacity charges for a probationary period not to exceed 15 months. If a QF can meet the minimum requirements during the probationary period, PG&E will pay the QF all capacity payments suspended during the probationary period and reinstate regular capacity payments. If a QF cannot meet its minimum requirements during the probationary period, PG&E may derate the contract capacity to either actual or reasonably expected deliveries, with the quantity by which the capacity is reduced being subject to termination provisions. If the failure to meet minimum requirements was caused by a forced outage,[1] the QF will not receive capacity payments for the month in which this circumstance occurred. During a force majeure, capacity payments will be continued for a period of 90 days following the occurrance.

Finally, PG&E's Appendix C provides no special provisions for any technology other than hydroelectric projects. The only separate provisions for small hydro QFs deal with the determination of the QF's monthly capacity rating. The procedure followed by PG&E mirrors the requirements of D.82-01-103, i.e., with the average dry year being based on the average of the five years of the lowest annual generation as derived from 50-year natural flow data. The small hydro QF is otherwise required to meet the minimum performance requirements for either payment option chosen.

(1) Positions of the Parties

During the hearings and in briefs, both criticism of and support for PG&E's performance requirements were voiced. Generally, IEP, whose views were shared by the State Energy Task Force, found all of the utilities' proposals too rigid and, like the CEC, endorsed statewide performance standards which would be more

[1] PG&E defines forced outage as any outage resulting from a design defect, inadequate construction, operator error, or a breakdown of the mechanical or electric equipment that fully or partially curtails the electrical output of the QF.

flexible. IEP asserts that PG&E's offer improperly excludes wind and waste-to-energy facilities by imposing overly strict performance standards during summer peak periods and inflexible scheduled maintenance requirements. Other parties, including CMA, Calcogen, and Kimberly-Clark, however, endorse PG&E's approach which allows performance to be measured by availability as well as energy production. The staff concludes that, with certain modifications, PG&E's Option 1 is a reasonable model for an offer based on availability.

Parties both supporting and disputing PG&E's general approach, however, also had a number of specific recommendations. To begin with, it was urged that payments above 100% of PG&E's shortage costs should be offered to QFs whose performance exceeds the operating standards normally expected of PG&E plants. The staff suggests that payments should be provided up to 125% of PG&E's capacity costs and should be calculated according to a recommended formula for an additional capacity credit. Staff also suggests that PG&E's definition of dispatchability be modified to give the utility the right to require only increases, not decreases, in a QF's operation and to limit dispatchability to on- and mid-peak periods and emergencies.

IEP and other QFs ask that statewide maintenance standards be adopted which would allow (a) hourly use of the allotted time, (b) an additional 45 days or use of accumulated unused days every three years for major overhauls, and (c) notice requirements related to the amount of time to be used (i.e., 24 hours' notice for a maintenance period less than 24 hours, seven days' notice for maintenance in excess of 24 hours, and six months' notice for major overhauls). The special needs of waste-to-energy projects which require 55 days a year for maintenance should be recognized.

IEP and the staff also urge that all capacity payments should not be suspended during PG&E's probationary period. IEP testified during hearing that such an interruption in cash flow could cause a QF to meet its debt service obligations. Both the staff and IEP recommend that during the probationary period the QF be paid for the actual level of capacity performance it can achieve. At the end of the period, payments should be reinstated based on the level of operation which the facility can reliably perform. Staff states that the capacity payments suspended for the capacity actually delivered should include an allowance for forced outages.

Finally, a number of the parties recommend that adjustments be made in PG&E's approach for small hydro and waste-to-energy facilities. Staff concludes that since the contract capacity of a small hydro facility is based on the average of five years low flow during peak months, such a facility should not be further penalized for failing to meet PG&E's peak availability standard in years when flow is less than the five-dry-year average. Staff recommends that PG&E's performance factor, part of the payment calculation for Option 2 QFs, should be set at 1.0 in establishing the nameplate capacity for small hydro QFs and that the peak availability requirement should be waived. Further, staff urges that termination provisions should not be applied to hydro QFs who fail to deliver the contracted capacity only because of low flow conditions.

For waste-to-energy projects, the staff asks the Commission to consider developing over the next year the proper data and methodology required to base capacity payments to waste-to-energy projects on the combined performance of all such projects during the peak months. The group performance would be compared to a utility's baseload plants and the individual waste-to-energy facility would be paid according to its performance as compared to that of the group.

(2) PG&E's Response

In its brief, PG&E asserts that the provisions of its Appendix C are in full compliance with the OIR 2 decisions. Only to accommodate QF development does PG&E suggest any modification of its approach. In particular, it is PG&E's opinion that no adjustments to its minimum performance requirements are necessary for specific technologies, such as wind or solar, since a QF which cannot meet those requirements is less valuable to the utility than one which can. Further, a QF always has the option of signing an as-available contract which was specifically designed to accommodate resource uncertainty.

With respect to payments above 100% of PG&E's shortage cost for QFs whose performance exceeds utility plant, PG&E argues that such a payment should only be made to QFs that can actually outperform utility combustion turbines and only if they can do so on a consistent basis. PG&E allows QFs to have a "liberal" 20% peak period forced outage rate under its standard offer but contends that its own peaking units have forced outage rates that are actually less than this amount. Therefore, for QFs to receive payments in excess of the combustion turbine shortage cost proxy, they must outperform this higher standard of the combustion turbine (i.e., a 10% or 15% forced outage rate). Further, they must commit to achieve this performance on a consistent basis.

On the issue of scheduled maintenance, PG&E contends that the standard offer should not become a "lowest common denominator" contract which is stretched to accommodate specific technologies that cannot meet reasonable requirements. For a QF which cannot meet PG&E's requirements, a special agreement or an as-available contract again is always an option. PG&E is willing, however, to allow a QF when it enters the contract either (1) to take only a portion of the allowed number of days per year for scheduled maintenance and combine the remaining days over three years into maintenance periods for major overhauls or (2) arrange an average of 35 days per year over the life of the contract allowing an increasing number of days for maintenance as the project ages.

PG&E is also of the opinion that a probationary period of at least 15 months is necessary to allow PG&E to assess the level of capacity the QF can reliably deliver or make available during the peak months after it has failed to perform. PG&E is willing, however, to redraft its provisions covering the suspension of payments during this period in keeping with the suggestions made by IEP during hearings.

Specifically, PG&E proposed that under Option 1, if a QF fails to meet the minimum performance requirements, it will continue to receive capacity payments for the amount of dispatchable capacity available during the probationary period. If after the expiration of this period, the QF has not demonstrated an ability to provide its full contract capacity to the utility that capacity would be derated subsequent monthly payments limited to the new contract capacity. The amount by which the QF's capacity is reduced will be subject to termination provisions.

For Option 2 QFs, the same opportunity to earn capacity payments during the probationary period for the amount of capacity actually delivered will be provided. If the QF fails to deliver the full contract capacity during each of the following year's peak months, the contract capacity will be derated to the lower monthly amount of capacity actually delivered during the peak months. The lost capacity will again be subject to termination provisions.

PG&E does not support staff's position regarding adjustments of PG&E's capacity payment formula for small hydro QFs. According to PG&E, a hydro QF already benefits from the increase in its capacity rating caused by basing that rating on the average of five dry years, rather than the driest year. PG&E does believe, however, that hydro QFs during the "drier" year should have their capacity payments suspended, as opposed to having the contract terminated, as follows:

> "1. Hydro QFs which have their capacity ratings based on the five dry year average should not have their capacity terminated or derated when their failure to meet the minimum performance requirements is due solely to the occurrence of a dry year which is drier than the five dry year average.
>
> "2. During 'drier' year conditions, capacity payments to hydro QFs

should be suspended. Capacity payments should resume, at the contract price, when hydro conditions once again reach the level used to determine the capacity rating." (PG&E's concurrent brief, at pages 31-32.)

b. Edison Standard Offer No. 2 Part I, § 13 (General Terms and Conditions - Availability) and Appendix B. 2 (Capacity Payments for Firm Power Purchases)

Unlike PG&E, which offers payments for firm capacity based on availability and energy production, Edison's standard offer provides only one basis of payment for a firm power purchase - the QF's energy production. Basically, under Edison's firm capacity offer, the QF is paid according to its output or capacity factor. In addition, its emergency availability is considered.

The QF's output or capacity factor is taken into account in two ways in the payment provisions included in Appendix B. 2 of Edison's Standard Offer. First, the QF is paid more for achieving a higher capacity factor or a level of kWh output that is a higher percentage of the maximum possible kWh output given the kW contract capacity. At an 80% capacity factor the QF is paid 100% of the per kW capacity price for each kW of contract capacity. At higher capacity factor levels, representing performance in excess of Edison's plants, the price paid per kW is escalated further, up to a maximum of 124% of the basic per kW capacity price for 100% capacity factor performance.

The second way in which output is taken into account is through Edison's "hurdle factor". If a QF output falls below a 50% capacity factor (the "hurdle"), its capacity payment is cut in half for that period. Edison claims that this hurdle factor takes into account QF reliability because QFs that do not perform within a certain range (greater than the hurdle) are less reliable and less valuable.

The "hurdle factor" is the only aspect of Edison's offer that indirectly requires a prespecified level of output. As noted earlier, under PG&E's output-based option, QFs must meet an 80% summer peak output requirement or face probation and termination of all or part of their contract capacity. Here, QFs must meet a 50% output level in any month (not just peak summer months) or their payments are reduced. Under the Edison scheme, termination penalties would not apply.

Edison's offer also has an emergency availability requirement. Emergency availability is defined in Section 13.2 as follows:

> "At Edison's request seller shall, within 30 minutes of such request, make all reasonable effort to deliver power at an average rate of delivery at least equal to the (contract) capacity...during periods of emergency."

If the QF Seller fails to respond, its capacity payments are reduced by one-half for the six months following the request "until Seller demonstrates (the) ability to deliver full capacity pursuant to Section 13, Part I, or until Seller responds to a subsequent request for full capacity, in which case the six-month capacity payment reduction shall be waived for the remaining reduced payment monthly billing periods." In all cases, however, the reduced payment will apply to the month in which the Seller fails to respond to a capacity request.

In addition to these requirements contained in Appendix B. 2, Section 13 also provides that a QF which fails to respond to an emergency when first requested by Edison will not have its capacity payments reduced. However, after this initial request, whether complied with or not, any subsequent failure by the QF to comply with a request by Edison will result in the aforementioned 50% reduction of capacity payments specified in Appendix B. 2. Failure to comply with a request during an existing six-month reduced capacity payment period will extend that period to six months following the latest failure.

Edison contends that its "availability factor" provides a specific way of valuing QF emergency availability, one of the factors that required by D.82-01-103 to be reflected in the firm capacity payment. The availability criterion is somewhat analogous to the availability required under PG&E's dispatchability option (Option 1) except that there is no allowance for forced outages as in the PG&E's example, and under the Edison's offer the requirement is a part of an output or capacity factor-based payment scheme.

Edison's payment formula also reflects adjustments for scheduled maintenance. Specifically, Edison allows a maximum of 480 hours (20 days) per year for scheduled maintenance and an additional 1,080 consecutive hours (45 days) once every three years for major overhauls. In Part I, Section 8.4, of its offer, Edison defines reasonable advance notice of scheduled outages, including any reduction in capacity availability as 24 hours for an outage of less than one day, one week for an outage of one day or more, and six months for major overhauls. The off-peak hours are to be used for scheduled and routine maintenance and the QF is required to make reasonable efforts to limit its outages during on-peak and mid-peak periods.

(1) Positions of the Parties

Many of the parties found the same general shortcomings in Edison's offer as PG&E's. For example, QFs complain that here, as in the case of PG&E, many performance requirements are rigid, "all or nothing" type requirements that do not adequately reward partial performance.

In addition, a number of specific criticisms of Edison's offer were raised. In particular, several QFs complain that Edison has failed to make an offer based on availability similar to PG&E's. Staff agrees that Edison should havve an availability option. In staff's view, a forced outage rate is the proper performance criterion under such an option. Staff also contends that this availability option should reflect, as Edison's current "output" offer does, a higher payment for operation better than Edison's plants.

QFs note that whereas PG&E's performance requirements would appear to exclude technologies that cannot be dispatchable (Option 1) or meet an 80% summer peak output requirement (Option 2), Edison's offer would not exclude any technologies. In other words, under Edison's offer, there would be no lower limit or absolute eligibility for the firm capacity contract, as even QFs that cannot meet the availability and hurdle factors would receive some capacity payment, however small. Still, many parties object to the hurdle and availability factors as being too rigid and harsh. The deletion or adjustment of these factors is recommended, particularly for certain technologies.

Staff observes that Edison's own plants would have difficulty meeting a 30-minute response time required by Edison for QF emergency availability. Instead, staff argues that Edison should only require that a QF make reasonable efforts to respond to an emergency as soon as feasible consistent with its capabilities. CMA also agrees that technical feasibility is the proper criterion for meeting any emergency and argues that lack of emergency availability should not have such a major impact on capacity payments since it represents only a small fraction of a utility's total avoided costs. IEP suggests that the availability factor should not be applied to a QF on full or partial forced outage which has notified Edison in advance.

IEP recommends that a sliding scale be used in applying the hurdle factor rather than a single 50% capacity factor cutoff. IEP contends that this sliding scale will better reflect the actual level of capacity the QF is contributing to the system. The State Energy Task Force voices the concern that neither the hurdle factor nor the availability factor is applied to Edison's own plants and that these factors require QFs to meet a stricter performance test than utility plants.

If the availability and hurdle factors are to be adopted as proposed by Edison, several of the parties urge that the availability factor be waived for solar (both solar-thermal and solar-photovoltaic) and wind technologies, with wind's nameplate capacity being derated by 20%. For reasons similar to its suggested modifications of PG&E's offer for small hydro, staff recommends that Edison's period capacity, hurdle, and availability factors be set at 1.0 for hydro QF's whose capacity rating is based on the average of the five lowest flow years. For waste-to-energy projects, IEP and the California Waste Management Board ask that these QFs be given a longer time to respond to an emergency consistent with the technology (eight hours) and that the calculation of their capacity payment not include the hurdle factor.

Most parties endorsed Edison's basic approach to the allowed time and notice for scheduled maintenance. IEP, for instance, recommends Edison's offer as a model for statewide scheduled maintenance standards. IEP would only modify Edison's language by increasing the yearly allowance for scheduled maintenance to 35 days. For waste-to-energy projects, the California Solid Waste Waste Management Board again recommends a yearly allowance of 55 days.

(2) Edison's Response

Like PG&E, Edison believes that its performance criteria for firm capacity payments fully comply with the OIR 2 decisions. In particular, Edison asserts that both its availability and hurdle factors are reasonable. Edison argues that QFs that cannot consistently achieve a capacity factor above its 50% "hurdle" are less reliable and less valuable and they should, therefore, have their capacity payment reduced as Edison does in its standard offer. Similarly, Edison believes that a QF which is not available during emergencies is less valuable and that this situation also warrants reduced capacity payments.

Edison argues that the emergency availability requirement is appropriate even if Edison does not impose a similar requirement on its own plants and its plants and the QF plant are treated differently. Edison contends that it is appropriate to treat the two differently since they have different obligations. The utility, by virtue of its retail franchise, has an obligation to serve customers at all times whereas the QF has no incentive beyond price to serve Edison's ratepayers during emergencies. Edison contends that the 30-minute response time that it requires for QF emergency availability is reasonable and that any adjustments should only be considered on a case-by-case basis.

Edison does offer to modify the application of its hurdle and availability factors for specific technologies. In particular, Edison has adopted the adjustments suggested by the staff for wind, solar, and hydro with the exception of retaining the period capacity factor for small hydro to permit the capacity payment to be based on actual performance.

Edison also states that it is willing to pay QFs in dollars per kW per month based on availability, but only if the QF is fully dispatchable and is as reliable as Edison's generating resources. According to Edison this dispatchability and reliability will require (1) an accurate measurement of QF availability during each time period for each season; (2) detailed, accurate, and verifiable QFs records with periodic company review to determine a QF's actual energy production; (3) a QF being the functional equivalent of an Edison combustion turbine or the purchased power used by Edison to develop its shortage costs; (4) a QF's performance being measured individually and not in the aggregate; and (5) full dispatchability permitting the utility to increase and decrease generation. As in the case of PG&E, staff disagrees with this view of dispatchability and recommends that Edison should not have sole discretion over a QF's operation and should be allowed only to require increases in a QF's production or availability.

In recognition of the wide variation of QF's scheduled maintenance requirements, Edison endorses modification of its standard offer to allow more flexibility in scheduled maintenance allowances. Specifically, Edison will provide 35 days of scheduled maintenance per year and a year-to-year accrual of unused maintenance days, not to exceed 45 days.

c. SDG&E Standard Offer for Firm Capacity, Section 6 (Purchase Price of Energy and Capacity) and Exhibit C (Capacity Payment Schedule for Firm Capacity QFs)

SDG&E offers two payment options to QFs signing its firm capacity contract. Both options, set forth in Exhibit C of the offer, are based on energy production, as opposed to availability, and the choice of capacity payment option is limited by the payment option selected for the QF's sale of energy to SDG&E. If a QF elects energy Option 1 (as-available energy), it will be paid for capacity only according to capacity Option 1. A QF choosing energy Option 2 (five-year forecast) can be paid for capacity under either capacity Options 1 or 2. The two options for capacity payments are based on two different performance criteria which must be met for payment.

Under Option 1, capacity payments are made on the basis of the QF's output or energy actually delivered. A QF starts with a certain levelized annual capacity price in dollars per kW which varies depending on the length of the contract that the QF signs and the year its operations start. This annual price is spread to different hours within the year based on a "supply factor", an allocation factor that values capacity more during seasonal or daily peak demand hours. The resulting ¢/kWh capacity prices for different time periods are paid to the QF for all the kWh energy output that it provides in each time period. There are no prespecified output or availability performance levels that must be met. There are no conditions to or limitations on scheduled maintenance.

Option 2 is entitled Payment by Capacity ($/KW-month). Under this option, payment is based on output or capacity factor and requires that certain peak period performance standards be met. The Option 2 monthly capacity payment equals the product of the Equivalent Capacity Factor (ECF) and the appropriate $/kW number in the capacity table again determined by the length of the contract and the QF's operation date. The ECF is calculated as follows:

$$ECF = \frac{O \times A}{C \times (H-S) \times H}$$

Under this formula, Q represents the delivered energy in kWh during monthly on-peak and semi-peak time periods; A is a monthly capacity allocation factor differentiated by season; C is the contract capacity; H stands for the total monthly on-peak and semi-peak hours; S is a QF's monthly scheduled maintenance during on-peak and semi-peak hours, which is not to exceed 75% of H; and R is the reliability of SDG&E's system alternative capacity source. R currently has a value of 0.85.[2]

To be paid under this formula, a QF must (a) deliver enough output during peak and semi-peak hours of the month so that the monthly ECF is greater than 0.5 and (b) schedule outages at least six months in advance during periods acceptable to SDG&E. Scheduled outages must not exceed 720 hours (30 days) in any 12-month period. Agreed dates for scheduled maintenance cannot be changed without notice.

If the QF fails to meet the minimum performance provisions set forth in Exhibit C, SDG&E will immediately suspend or reduce the capacity payments to the QF for a probationary period. The terms and conditions of this suspension, set forth in Section 16.5 of the standard offer, are similar to those in PG&E's standard offer, except that the probationary period is not to exceed 14, as opposed to 15, months.

2 SDG&E bases this 85% reliability on its own peaking plants, which is asserts have, at most, a 15% outage rate.

(1) Positions of the Parties

Unlike their response to the offers of the other utilities, a number of QFs, generally represented by IEP, endorse SDG&E's approach and urge its adoption for both PG&E and Edison.[3] IEP believes that SDG&E's two-option contract will appeal to a wide variety of QFs. In IEP's opinion, SDG&E's Option 1 correctly recognizes the valuable contribution which a QF can make to the utility system just by signing a long-term commitment. Although a QF could achieve a higher payment agreeing to the more stringent requirements of Option 2, a QF who agrees to Option 1 will receive a payment 15% below that of an Option 2 simply by making a long-term commitment.[4]

Other parties however, did find deficiences in SDG&E's offer. Among other things several parties pointed out that SDG&E does not have an option (such as PG&E's) which values QF's performance based on availability rather than energy production. Further, it was claimed that SDG&E does not allow payment above the 100% shortage cost level for QFs that exceed the performance of utility plant. Staff contends that under Option 1 ¢/KWh payments, a QF that achieves a 100% capacity factor, a performance level better than utility plants, will only receive 100% of the combustion turbine capital cost proxy, not some higher level. Staff would have the Option 1 QF receive 100% of the shortage cost proxy for 80% capacity

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3 IEP specifically suggests that PG&E's and Edison's offers would be acceptable if an option like SDG&E's Option 1 were also part of these offers.

4 QFs under Option 1 receive 100% of the $/kW annual capacity price for a 100% capacity factor during the year, while QFs under Option 2, by virtue of the "R" in the formula listed above, receive 100% of the $/kW annual capacity price for an 85% capacity factor performance.

factor output and 125% for 100% output. Similarly, under Option 2, staff would have the QF receive 100% of the capacity price for an 80% capacity factor, rather than 85% as now specified by the reliability factor, R. Use of the 80% standard by staff is based on their estimate of the average reliability of SDG&E's plants or its system as a whole.

None of the parties suggested any adjustments to SDG&E's payment option or performance requirements for specific technologies. Comments regarding PG&E's suspension of payment provisions and scheduled maintenance allowance were equally applicable to SDG&E.

(2) <u>SDG&E's Response</u>

SDG&E is willing to modify its firm capacity offer so that the choice of capacity option will not be limited by the type of energy payment chosen. However, SDG&E concludes that both its Options 1 and 2 are reasonable and consistent with OIR-2. According to SDG&E, Option 1 reflects an aggregate value of firm capacity and is intended for QFs which are unable or do not desire to guarantee a minimum degree of availability. Under these circumstances, Option 1 will be a useful tool in making the standard offers widely applicable to QFs. SDG&E acknowledges, however, that the factors recited in D.82-01-103 for inclusion in a payment for firm capacity are actually contained in its capacity payment Option 2.

With respect to Option 2, SDG&E does not believe it is necessary to have an availability option under which the QF is dispatchable. SDG&E concludes that it would be impossible to measure availability when it is not based on actual output, but is based on a measure of forced outages and the potential to produce output.

Further, SDG&E argues that its Option 2 actually reflects availability since it requires QFs to produce a certain amount during peak and semi peak hours. SDG&E's minimum ECF of 0.5 under Option 2 is a standard of peak period reliability and availability.

SDG&E disagrees with staff's contention about payments above 100% of the shortage cost. For Option 1 type QFs, SDG&E argues that they are less reliable and therefore should only receive a maximum of 100% of the shortage cost for 100% capacity factor output (similar to the as-available capacity payment). For Option 2 QFs, SDG&E argues that payments above 100% are allowed for capacity factor performance above 85%. This 85% standard is based on a conservative assumption of its combustion turbine plants' reliability. SDG&E disagrees with staff's use of an 80% standard as it incorrectly is based on system reliability rather than peak or plant reliability. Use of the latter standard is appropriate in order to be consistent with the shortage cost proxy approach.

SDG&E offers no changes to its provisions governing suspension of payments or scheduled maintenance. SDG&E observes that its scheduled maintenance allowance is already sufficiently flexible, particularly since restrictions on maintenance only apply during peak and semi-peak periods.

d. Discussion

In D.82-10-103 the utilities were directed to draft a firm capacity contract, designed for QFs that could meet certain operating standards, and an as-available capacity contract, designed for QFs that could not, or did not desire to, meet such standards. The operating or performance standard envisioned in D.82-01-103 for firm capacity QFs was to be a standard which required QF availability during system peak periods. The standard was to be designed to reflect aspects of peak period availability such as dispatchability, reliability, availability during emergencies, scheduling of outages, and contract duration, termination, and sanctions. QFs that signed contracts as firm power sources were to meet this specified standard of performance.

We have before us three general types of performance standards in the utilities' filings. The first is a performance standard based on a level of peak period availability, as exhibited by PG&E's Option 1. The second is a performance standard based on a level of peak period output, as exhibited by PG&E's Option 2, SDG&E's Option 2, and Edison's single payment offer. The third is a performance standard that requires only a commitment to a certain contract length with no specific peak period output or availability. This approach is embodied in SDG&E's Option 1.

We find that PG&E's Option 1 availability standard, with the modifications discussed below, is in compliance with the requirements of D.82-01-103. Indeed, as the requirements of D.82-01-103 are oriented towards QF peak period availability, this availability type of standard most clearly follows from this decision. Under this option the QF is dispatchable and available for emergencies. Moreover, because of the limitations on peak periods forced outages, peak period reliability is assured. Nonperformance is deterred by the application of termination provisions. Requirements are made for scheduled maintenance.

All three utilities have proposed a performance standard that is based on a QF achieving a certain level of peak period output. D.82-01-103 specifically allows for a performance option based on capacity factor or output rather than availability. Output requirements are an indirect way to assure availability for nondispatchable units.

We consider PG&E's Option 2 with the modifications discussed below, to be in compliance with D.82-01-103. Under this option the QF must deliver its contract capacity to PG&E at least 80% of the time during the peak hours of the peak summer months. During other periods there are no specified performance requirements, other than scheduled maintenance limitations.

Turning to the aspects of peak period availability recited in D.82-01-103, it is clear that the peak period output requirement in PG&E's Option 2 assures reliable operation during the hours of the year when reliability is most important. The QF under Option 2 is not dispatchable, but the peak period output requirement and the general weighting of capacity prices toward peak and semi-peak hours assures that QFs will operate during most, if not all, of the same periods as they would have had they been under the dispatcher's control. D.82-01-103 specifically allows for nondispatchable QFs to be accommodated in the firm standard offer. Time-of-use pricing and peak period output requirements under Option 2 will also assure that QFs will be delivering their capacity during the most likely emergency periods. Finally, maintenance scheduling and termination provisions apply as they do in the case of PG&E's Option 1.

The essential requirement of performance under both PG&E's Options 1 and 2 is the 80% summer peak hour availability or output requirement. IEP has argued that this standard is too stringent and one that many utility plants could not meet. We consider the standard to be reasonable for QFs that sign up as firm sources and receive capacity payments based on the combustion turbine. Evidence in this proceeding, with which IEP concurred, indicated that utility peaking plants, such as combustion turbines, have an average peak period availability of greater than 80%.

We do agree with IEP that PG&E's options are too stringent in other ways, such as its requirements for scheduled maintenance. As discussed below, we will require certain changes with respect to this and other performance requirements.

IEP also argues that an 80% peak availability or output requirement is too flexible and is of an "all or nothing" nature. We disagree. Under the reduction in payment provisions which PG&E proposed in its brief, discussed below, a QF that does not achieve the 80% availability or output standard will still receive a payment commensurate with its actual production and will have the opportunity to have its original capacity payments reinstated if its availability or output reaches the 80% level during the probationary period.

The flexibility of the standard is also enhanced because it may, if need be, only apply to part of the QF's total capacity. In other words, if a 10 MW QF facility produces consistently at a 5 MW level and sporadically at higher levels, the QF can sign up for 5 MW of firm capacity (which meets the 80% standard) and sell the rest of its output on an as-available basis.

SDG&E's Option 2 is like PG&E's Option 2, based on the QF's output. In certain cases, however, this option imposes a more lenient performance standard than PG&E's by requiring only a 50% output level which the QF may fail to meet and still not be exposed to termination or probation provisions. On the other hand, the 50% standard applies to peak and semi-peak hours during all months of the year, not just summer month peak hours. Partial capacity payments are also not allowed for performance that is somewhat below the standard. If the 50% level is not met, the QF receives no payment for that month.

We do not find SDG&E's Option 2 to be in compliance with D.82-01-103. The 50% standard is, in our view, not an adequate level of peak availability and reliability, even if it does apply to more hours of the year. The firm capacity performance standard should be oriented toward the system peak hours when reliability is of greatest concern. It should be a level of reliability that is commensurate with the utility plant that is avoided by QF purchases. Utility plant has a higher level of peak period availability than 50%. Also, it is more reasonable, in our view, to allow more flexibility than SDG&E allows by giving partial payment, rather than zero payment, for performance below the standard. Further, SDG&E's zero payment for nonperformance does not differentiate between temporary and repeated nonperformance. More flexibility should be allowed for temporary nonperformance with termination provisions applied only to continued performance.

We also find that Edison's output-based performance standard is not in compliance with D.82-01-103. Edison's basic performance standard is a 50% output level, incorporated in its "hurdle" factor. In Edison's offer this standard applies to all periods - peak, mid-peak, and off-peak - in all months of the year. Failure to meet this standard results in a 50% reduction in the capacity payment. Edison also requires emergency availability. Failure to meet this standard results in an additional 50% reduction in the payment.

Edison's performance standards do not adequately focus on peak period availability as required by D.82-01-103. Apart from the emergency availability requirement, there is little differentiation between required peak and off-peak performance. The 50% output level is also too lenient for the peak period. On the other hand, the emergency availability requirement is too stringent and places too much emphasis on one aspect of peak period availability. It is for these reasons that we find tha Edison's performance requirements for firm capacity QFs do not comply with D.82-01-103.

The final type of performance standard that we must consider is SDG&E's Option 1. This option appears to be a hybrid of the standard offers approved in OIR 2, an offer which could lead essentially to a long-term as-available capacity contract. Although a QF electing SDG&E's Option 1 would be committing its resource for a specified period of time at a price which would vary by time of energy delivery, the QF would not be required either to be available during peak periods and emergencies or to match the reliability of SDG&E's own plants. We understand the reasons many QFs have found such an option desirable, i.e., the opportunity to have payments which would be levelized and possibly greater than those paid an as-available producer. Nevertheless, Option 1, failing to reflect the required performance standards, is not an option to purchase firm capacity as defined in D.82-01-103. While we might cosider such a hybrid in the future, it was neither contemplated by nor in compliance with that decision.

Because of our conclusions, it will be necessary for the utilities to refile their standard offers in conformance with this order. Although we believe that PG&E's Options 1 and 2 can serve as appropriate models for firm capacity standard offers based on availability and energy production, even these offers require modification. Neither SDG&E nor Edison will have complied with the OIR 2 decisions until each offers payment options based on a QF's availability and energy production equivalent to those offered by PG&E, as modified herein.

To achieve overall compliance with this decision and OIR 2, the following principles should be incorporated in the utilities' firm capacity standard offers.

(1) Dispatchability

We concur with the staff that the definition of dispatchability used in PG&E's Option 1 and any other offer based on availability should give the utility the right to require only increases, not decreases, in a QF's operation. At this time the language employed by PG&E (required capacity deliveries "at any level up to the full contract capacity") is ambiguous, but appears to permit both upward and downward dispatchability. We agree with the staff that the ability of a utility to interfere with a QF's operations in such a manner is unwarranted and unreasonable. The utility should not be in a position to unilaterally jeopardize a QF's operation and in turn reduce its payments. Regarding dispatchability, D.82-01-103 only required that a QF be sufficiently dispatchable to be available for a utility's increased needs during peak periods and emergencies. For these reasons, we also find Edison's approach to dispatchability too restrictive.

We do not believe it is necessary, however, to define dispatchability as limited to on- and mid-peak periods and emergencies if an approach like PG&E's is used. Such a limitation is both implicit and explicit in PG&E's Option 1. For the peak months, a QF signing Option 1 is required to have 80% of its capacity available only during the peak hours and for the remainder of the year need only maintain a somewhat flexible forced outage rate.

Because PG&E offers no method for checking on a QF's ability to respond in every hour of each day, but rather uses an on-call approach, a QF will at least have the minimum ability to respond consistently to system emergencies which cannot be predicted.

While we could adopt Edison's response time (30 minutes) criterion for emergencies, we believe that the record in this proceeding is not sufficient to designate a specific response time for all utilities and that PG&E's requirements essentially accomplish this same result by ensuring a QF's readiness to perform. The only time PG&E would possibly need to increase a QF's supply is at times when its own demand increases (i.e., peak, semi-peak, and emergencies). PG&E's approach allows a QF to meet all of these performance factors without placing an unreasonable burden on a QF's operation or one inconsistent with PG&E's plant operations.

(2) Payments in Excess of a Utility's Capacity Costs

We conclude that an option is not in compliance with D.82-01-103 or this order unless it provides for payments in excess of a utility's capacity costs to QFs whose performance exceeds that of the utility's plants. We do not believe that a firm capacity QF must be the exact functional equivalent of a utility's peaking combustion turbine to receive an offer based on 100% of a utility's capacity costs. However, we do agree with PG&E that to receive higher payments the QF's consistent level of performance should exceed the minimum level of availability of the peaking unit used as a proxy to calculate the utility's shortage costs. Such a requirement will ensure that the utility will not pay more than its avoided costs, the previously determined level of payment found reasonable for QF purchases.

Testimony during hearing indicated that the availability factor of a combustion turbine could range from 80% to 94%. To receive higher payments, a QF should at least meet a comparable level of performance during the utility's peak periods. We believe that it is reasonable, therefore, to require that a QF achieve a peak period availability or capacity factor in excess of 85% before receiving capacity payments in excess of 100% of the shortage cost proxy. Thus, a utility's payment options should include an offer to pay a price higher than the utility's stated capacity costs for those QFs (1) who demonstrate an availability of 85% or better during time periods similar to those specified in PG&E's Option 1 or (2) who deliver capacity during the peak periods at a capacity factor of 85% or better under an output option like PG&E's Option 2. Under these circumstances, a QF who performs at this higher level could receive up to 118% of a utility's shortage cost.

We believe, however, that an additional requirement should be imposed in an availability option which permits the higher payment. PG&E currently intends under its Option 1 to measure a QF's dispatchability by placing the QF "on-call". We believe that a more certain measure of the QF's dispatchability should be required if a QF is to receive payments above a utility's avoided costs in order to ensure whether and at what level the QF actually exceeds utility plant operations. Such a demonstration is therefore required not only to justify the higher payment, but to determine the appropriate level of that payment.

For this reason, we will direct the utilities to include in their standard offers a reasonable method of determining the QF's consistent ability to be available at a forced outage rate of 15% or less. Although SDG&E argues that more operating experience is required to determine a QF's forced outage rate, it is our view that having set the standard (performance at an availability factor of 85% or better) the utility can devise methods to review the QF's actual performance. It is <u>only</u> in this case of higher payments that Edison's reporting requirements which it felt were necessary for a QF to be dispatachable might be appropriate.

(3) Adjustments for <u>Specific Technologies</u>

Edison proposed certain adjustments in its firm capacity performance standards for solar and wind technologies. Basically, Edison is willing to waive its emergency availability standards for both technologies and waive the 50% "hurdle" or output standard for wind. Under these circumstances, the capacity payment for wind would be reduced by 20% while the solar payment would be unaltered. As we have not found Edison's performance standard to be in compliance with D.82-01-103, these modifications are essentially no longer at issue. As discussed earlier, we believe that the performance standard that we have adopted, modeled after that proposed by PG&E, offers sufficient flexibility for QFs that can meet a specified level of performance. QFs which cannot meet the specified level of performance can sign an as-available capacity contract or enter into negotiations for a nonstandard contract.

D.82-01-103 did provide a special capacity price adjustment, however, for small hydro facilities. We do find that some clarification of this adjustment is required.

Basically, we have concluded that the position taken by PG&E in response to this issue, recited <u>supra</u>, is reasonable with one exception. In its brief PG&E has suggested altering its contract provisions governing the suspension of payments for failure to meet its minimum performance requirements. Instead of suspending all payments, PG&E will modify its offer to specifically permit payment for the capacity actually delivered during the probationary period. Because we intend to adopt this approach, we believe it is consistent to permit hydro QFs operating during the "drier" year to be paid for the amount of capacity, if any, actually delivered to the utility during this "drier" year period. Capacity payments would resume at the contract price, with no retroactive payments, when hydro conditions once again reach the level used to determine the capacity rating. With this modification PG&E's recommendation should be included in every utility's firm capacity standard offer for hydro QFs whose payments are based on the five dry year average.

(4) Scheduled Maintenance

As in the case of availability requirements, we believe that scheduled maintenance requirements in the firm capacity offer should be reasonably consistent between utilities. We agree with PG&E that our standards for firm capacity should not be formulated based on the "lowest common denominator" and should not jeopardize avoided cost value. However, we also conclude that scheduled maintenance standards should be sufficiently flexible to permit various types of QF operation. Essential elements of any scheduled maintenance allowance should be (1) a reasonable allotment of days for both routine maintenance and major overhauls, (2) sufficient notice to aid utility system planning, and (3) appropriate timing to avoid periods of greatest demand on the utility system.

We believe that these basic principles are embodied in Edison's approach to scheduled maintenance with certain modifications. Therefore, an offer which complies with this decision and OIR 2 must allow the following:

a. Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis.

b. A QF may accumulate unused maintenance hours on a year-to-year basis up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls.

c. Reasonable advance notice to the utility of a scheduled outage will be 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for a major overhaul), and six months for a major overhaul.

d. Major overhauls shall not be scheduled during the peak summer months. Reasonable efforts to schedule or reschedule routine maintenance outside the peak summer months should also be made, but in no event shall outages for scheduled maintenance exceed 30 peak hours during the summer peak months.

e. No restrictions should be imposed on the use of the scheduled maintenance allowance during the initial period of operation (i.e., the first six months).

(5) Reduction of Monthly Payments

For payment options based on either availability or energy production, we generally adopt PG&E's altered approach for reducing payments following a failure to meet the utility's minimum performance requirements. PG&E's original proposal provided that such a failure would result in a total suspension of capacity payments for up to 15 months. Its modified approach, however, would permit payments for capacity actually delivered during the probationary period with the potential of the original payment level being reinstated or the QF's capacity derated at the end of that time depending on the QF's performance during the peak months. If the QF is unable to deliver its promised firm capacity, the utility should have the ability, as suggested by PG&E, to make that determination over a reasonable period of time. Given the peak month periods of all three utilities, a probationary period of 15 months is reasonable.

Within that time, however, the QF should not experience a total cessation of cash flow if it has a capacity contribution to make to the utility's system. The complete suspension of monthly payments when this circumstance exists is an unreasonably harsh penalty to impose on a QF whose failure to perform may have resulted from its level of operation during a single peak month. To permit the QF to continue to be paid for capacity actually delivered during the probationary period is a necessary and reasonable part of a more flexible performance requirement.

We agree with PG&E that the QF's ability to meet the minimum performance requirements in peak months following its failure should be used to determine whether its original capacity payment will be reinstated or its contract capacity derated. The difference between the contract capacity and the reduced capacity is appropriately subject to contract termination provisions. We also adopt staff's recommendation that for the capacity actually delivered during the probationary period an allowance or credit for forced outages at the level otherwise specified in the agreement should be included. In using this approach, no retroactive payment at the end of probation is necessary.

(6) As-Available Capacity Payments Prior to Firm Capacity Delivery

During hearing one additional recommendation was made by IEP witness Philip M. Huyck, which although not strictly a compliance issue, does relate to the performance required under a firm capacity contract. It was Huyck's suggestion that a QF under a firm capacity contract who produce energy during start-up periods before the facility is ready to begin delivery of firm capacity should receive an as-available capacity payment up to the time that its firm capacity operations commence.

Although PG&E and Edison agree in general principle with this proposal, staff asserts that the theoretical basis which supports a payment for as-available capacity does not exist for such a payment during a start-up period. Because of the generally short period involved for start-up and the fact that a utility would probably not have a large number of generating plants in start-up at the same time, there can be no aggregation of energy, as in the case of as-available capacity, to serve as the basis for the utility avoiding capacity costs. Staff suggests that under these circumstances only as-available energy payments should be allowed.

After reviewing IEP's recommendation, we find SDG&E's response to this issue to be the most appropriate. Specifically, SDG&E states at page 21 of its concurrent brief:

> "...If a QF has declared an Operation Date, which is defined to be the date the plant is deemed to be capable of reliable delivery of energy and capacity..., the QF will be expected to provide capacity from that date. If the QF is unprepared to deliver capacity at the Operation Date, a different date should be chosen. If the QF anticipates there will be start-up problems, but believes it is entitled to receive some capacity payments, SDG&E suggests that the QF execute an as-available contract of short duration to cover the period in which the QF anticipates start-up difficulties. When the QF is confident that it can provide firm capacity, [it] can commence performance under a firm capacity contract."

By adopting this approach, no additional provisions will be required in the firm capacity contract which might be in conflict with the basis of that offer or, as pointed out by the staff, the theory of an as-available capacity offer. SDG&E's suggestion illustrates the existing options available to a QF under the offers we have already approved.

2. Termination Provisions

While D.82-01-103 included contract termination as a factor to be reflected in firm capacity offers and payments, the decision set forth no specific guidelines governing such provisions. The utilities have properly responded to OIR 2 by including termination provisions in each of their firm capacity standard offers. Within these provisions are liquidated damage clauses intended to reimburse the utility for unearned capacity payments made to QFs and, in some cases, the utility's costs of replacing the lost capacity. Certain of the offers place a value on, and in turn propose a reduction in the damage amount for, advance notice of termination.

In addition to issues related to the damage clauses of the utilities' standard offers, some of the QFs questioned the application of termination provisions to a conversion from a simultaneous purchase and sale of energy to a sale of surplus only. The proposals of the utilities and the views of the other parties on each issue are summarized below followed by our resolution of the issue.

a. Damage Clauses

(1) PG&E - Standard Offer No. 2, Appendix D

PG&E's standard offer for firm capacity distinguishes between two types of termination: termination with prescribed notice (Appendix D, Section D-2) and termination without prescribed notice (Appendix D, Section D-3). The length of the prescribed notice is directly related to the amount of the contract capacity being terminated or reduced. This notice ranges from three months for 1,000 kW or less to 60 months for over 100,000 kW.

In the event the prescribed notice is given, the QF terminating its contract is only required to refund to PG&E an amount equal to the difference between the capacity payments already paid by PG&E and the total capacity payments which PG&E would have paid based on the period of the QF's actual performance. This approach is adopted to effect a repayment of overpayments in the early contract years that arise from levelization of the capacity price. Interest is to be paid on the refund at the prime rate as published by the Bank of America. For the amount of capacity terminated, the QF will receive, from the date of notice to the date of actual termination, capacity payments based on the capacity price adjusted to the period of the QF's actual performance.

For termination without prescribed notice, a QF is required to make the refund described above, as well as the following additional payment:

> "Seller shall pay PGandE a one-time payment equal to the amount of contract capacity being terminated times the difference between the current capacity price on the date of termination for a term equal to the balance of the term of agreement and the contract capacity price, pro-rated for the length of notice given, if any, by multiplying by one minus the ratio of the actual number (as set forth in paragraph D-2). In the event that the current firm capacity price is less than the contract capacity price, no payment under this paragraph D-3 shall be due either Party." (Section D-3.)

In support of its termination provisions, PG&E points out that the levelized capacity payments made under a firm capacity contract provide a steady revenue stream to the QF with a greater portion of the contract income being received in the early years. Without full contract performance, overpayments should be recaptured to ensure that the QF is only paid based on the costs the utility actually avoided from the QF's operation. In PG&E's view, interest on this refund is reasonable in recognition of the time value of money.

PG&E also believes that its method of calculating damages for termination without adequate notice is consistent with the principles of contract law. Specifically, PG&E contends that it has used an established measure of damages: the difference between the contract price and the replacement cost. According to PG&E, the presence of this provision also serves to encourage QFs to give adequate notice of termination, while limiting the damages caused by a QF to one year's worth of the replacement cost differential.

(2) Edison - Standard Offer
No. 2, Part I, Section 5

Under Edison's standard offer, a QF terminating the agreement is required to reimburse Edison for unearned capacity payments according to the following formula: (1 - X/N) times the total value of capacity payments paid to date of termination, where "X" is the number of completed years of service from the initial firm capacity delivery date and "N" is the firm contract length. No specific formula is designated for damages associated with Edison's replacement costs. Edison also requires a QF to provide evidence, "to Edison's satisfaction," of its ability to make potential termination payments.

Edison defends its approach, which places no value on advance notice, as requiring the contracting parties to live up to their obligations unless uncontrollable forces intervene. Edison is critical of contract provisions permitting a QF to "buy out" the remaining term of its contract, i.e., PG&E's proposal, since such provisions will encourage QFs to ignore their obligations. According to Edison, whenever a QF terminates, even with notice, the utility and its ratepayers are damaged at least to some extent by the utility having delayed or eliminated construction because of a QF's availability.

(3) SDG&E - Firm Capacity
Standard Offer, Section 16

SDG&E's firm capacity standard offer includes termination provisions similar to PG&E's contract. A distinction is made between a QF terminating with prescribed notice, for which the basis for reimbursement is specified (Termination Payment A, Section 16.2) and termination without prescribed notice, for which an additional one-time payment is required (Termination Payment B, Section 16.4). The major differences between the two utilities are SDG&E's notice periods (ranging from 12 months for 5,000 kW to 60 months for 20,000 kW or more), its adopted interest rate (simple interest of 12% per year), and its calculation of replacement damages. With respect to the latter difference, Termination Payment B is the sum of Termination Payment A and a one-time payment calculated by taking an adjusted capacity price, based on the QF's actual performance, and inflating that figure by 1% per month for the period of the QF's performance. This figure minus the original firm capacity price is then multiplied by the number of kWs terminated by the QF.

SDG&E supports its approach on grounds similar to those urged by PG&E. SDG&E also points out that adequate notice has a value since it permits the utility sufficient time to purchase or construct additional capacity. SDG&E does note, however, that only to enhance certainty in the contract terms did it adopt a simple interest rate of 12% per annum. Further, in SDG&E's view, while its method for calculating its one-time Termination Payment B is reasonable, its complexity might require a different approach, preferably that suggested by the staff below.

(4) Staff

The staff's proposed termination provisions are designed to reflect the principles that (a) standard offers should specify the consequences of a QF's termination; (b) termination provisions should encourage QFs to fulfill their contracts, but also encourage the QF to provide sufficient notice to allow a utility to replace the lost capacity; and (c) damages for termination should be calculated to make the utility and ratepayer whole. Guided by these principles, the staff adopts an approach that is somewhat similar to those proposed by PG&E and SDG&E.

Specifically, the staff endorses the distinction between QFs which provide adequate notice and those which do not. Staff adopts the notice periods proposed by SDG&E and the general concept of the recovery of overpayments with interest calculated at the prime rate as determined by a common reference source. According to the staff, however, the additional payment required of a QF which fails to give the minimum notice should equal 50% of the amount of the capacity overpayment calculated without accrued interest. The full "penalty" should be reduced in direct proportion to the length of notice the QF gives as compared to the prescribed notice period. Staff argues that the penalty should be based on a number that is known at the time the contract is signed, not an uncertain future capacity replacement cost figure. Staff therefore bases the additional payment required of QFs who fail to give adequate notice to the overpayment to be refunded, a payment which could be calculated for different termination dates at the time the contract is signed.

Staff also urges that a probationary period like that prescribed by PG&E should be applied by all the utilities not only to failures to deliver contracted capacity, but also to failures to maintain QF status or pertinent governmental authorizations, permits, and licenses. With respect to the latter failures, the 15-month period would provide time within which to correct those deficiencies without risking total contract termination.

The staff also argues that a QF should not be required to provide evidence of its ability to make potential termination payments. Finally, the staff recommends that the utilities should include clear examples in their standard offers of the operation of their termination provisions.

(5) Other Parties

CMA urges that the staff's recommendation of a "50% penalty" for early termination should be rejected as arbitrary. According to CMA, the QF and the utility should submit the matter to arbitration at the time of termination with the burden on the utility to show its actual damages. Other parties seem to suggest that any of the proposed termination "penalties" are arbitrary and should be rejected.

(6) Discussion

Our review of the utilities' termination provisions is not one to determine the utilities' compliance with OIR 2, since our decisions gave no specific directions in this regard, but rather the reasonableness of the utilities' proposals. In making this evaluation, we must initially decide what termination provisions should accomplish and whether those provisions should be standardized between the utilities.

On the first question, we agree with the staff that termination provisions should encourage QFs to fulfill their contractual obligations, provide reasonable certainty of the consequences of termination, and make the utility and its ratepayers whole. With respect to contract standardization, we conclude that there is no reason for the termination provisions to vary greatly between utilities with respect to the basic requirements of such provisions. The type of damages caused to a utility by a QF's termination should essentially be the same for every utility with the actual amount of those damages differing depending on each utility's capacity prices. Without such consistency between termination provisions, a QF could be too greatly advantaged or disadvantaged, for no apparent reason, solely on the basis of its location.

Each of the utilities has chosen to include liquidated damage clauses in its offer. Such clauses are not "penalties" as argued by some QFs, but are in fact an accepted method of making the party who is not terminating whole. The benefits of a liquidated damage clause include the limitation of damages to the amounts or formula prescribed in the clause and the parties' advance knowledge of how the damages for termination will be calculated. These characteristics of liquidated damage clauses make them desirable and reasonable for inclusion in a utility's standard offer for firm capacity.

We must next consider, however, what elements of a utility's damages should properly be covered by such a clause. All of the utilities have prescribed some method for reimbursement of unearned capacity payments. We believe that such reimbursement is appropriate for the reasons recited by PG&E. In particular, the utility is not required to pay more than its avoided costs for the purchase of energy from a QF. Any payment over this amount arising from price levelization should therefore be refunded to the utility.

The methods chosen by the utilities to calculate this reimbursement appear to result in essentially the same measure of repayment and are reasonable. The only element of the repayment which requires further consideration is the interest to be charged, if any, on the amount refunded. We conclude that to reflect the time value of money, an interest charge is required and further that such a charge should be determined uniformly by the utilities by reference to one source.

While various suggestions have been made, i.e., simple or prime interest rates, we believe that an appropriate standard is that used in relation to the utilities' balancing accounts. Specifically, we have adopted the commercial paper rate as the charge on funds held in the Energy Cost Adjustment Clause (ECAC) balancing account. In doing so we have made these observations: (1) a variable monthly interest rate, as opposed to a fixed rate, reflects actual market conditions; (2) compounding of interest best reflects the actual burden on the utility and ratepayer; (3) commercial paper is the lowest cost form of short-term borrowing available to the utilities for financing undercollections; (4) the Federal Reserve Statistical Release, G. 13, is a reliable indicator of the interest rate applicable to commercial paper, prime three months; and (5) recognition should be given of the higher cost of financing for SDG&E. (D.91296, 3 Cal PUC 2d 197 (1980).) In D.91296, based on these findings, PG&E, Edison, and SDG&E were ordered to conform the interest rates applicable to their various accounts to "the published Federal Reserve Board three months Prime Commercial Paper rate (plus 50 basis points for San Diego Gas & Electric Company)". (3 Cal PUC 2d at 202.) We conclude for reasons similar to those recited above that this defined commercial paper rate is a reasonable rate to be applied to the repayments required of a QF which terminates its contract.

While we have found reasonable the utilities' provisions for reimbursement in the event of termination, we must also consider whether it is reasonable and necessary for liquidated damages associated with a utility's replacement costs to be specified in the standard offer as well. Further, we must answer whether the amount of the utility's damages should be reduced or eliminated by a QF giving advance notice of its termination. We conclude that the standard offers should include both such provisions.

As stated by SDG&E, with notice depending on the amount of capacity being reduced or terminated, a utility would have sufficient time to replace that capacity, either through purchase or construction, prior to the capacity actually being lost. Although Edison argues that the utility will incur replacement costs at any time there is a termination, this position fails to recognize the utility's ability to mitigate these costs by being notified in advance of the termination.

We therefore adopt the distinction between QFs which terminate with prescribed notice and those which do not. The evidence in this case regarding appropriate notice periods depending on the amount of capacity being terminated is limited to the specific proposals made by PG&E and SDG&E. We believe that such a provision, however, can vary between utilities based on their best estimates of the time it will take them, given their individual operations and planning, to replace the lost capacity. We have no reason to question either SDG&E's or PG&E's notice periods. Edison, however, will be directed to prescribe a table similar to that used by those utilities prescribing varying lengths of notice for the amount of capacity being terminated up to the maximum capacity any QF could have. Thus, upon termination, QFs giving the prescribed notice will only be required to reimburse the utility for overpayments.

For QFs who fail to give the requisite notice, we find reasonable for all utilities PG&E's approach to calculating the damages to be added to the refund for overpayments. PG&E's formula is less complex than that used by SDG&E, provides certainty with respect to the QF's financial obligations upon termination, and recognizes the value of the notice which is actually given.

PG&E's proposal, however, requires one modification. Under the terms of PG&E's offer, a QF is required to pay only one year's worth of the utility's replacement costs. If the notice periods adopted by PG&E and the other utilities are a true reflection of the time which the utility needs to replace the lost capacity, the adopted damage formula should reflect that needed time. Thus, a QF which was required under the contract to give five years' notice of termination, but only gave two, should be obligated to pay three years' worth of the utility's replacement costs. For those QFs with notice periods under one year, as provided in PG&E's standard offer, the damage formula should also be adjusted to reflect a payment of replacement costs which corresponds to the required notice period.

These modifications are necessary in part to respond to the reasonable requirement that the liquidated damage clause, as much as possible, reflects the utility's actual damages. For this same reason, we reject staff's suggestion that the utilities' references to future capacity prices be deleted from their offers and that the additional payment for failure to give adequate notice be based on 50% of the levelization overpayment. While it would certainly be beneficial for a QF to calculate its exact termination payment at the time of signing the contract, such a circumstance is not one of the principles of termination guiding our decision and, in fact, may conflict with the accepted standard of damages of making the nonbreaching party whole. The replacement costs which the utility will incur will, in fact, depend on the cost of new capacity at the time of termination, not at the time of contract signing.

We also find Edison's requirement that a QF provide evidence of its ability to make potential termination payments burdensome and unreasonable. While Edison is no doubt properly motivated to protect its ratepayers, such a provision is not a usual prerequisite in contracts and does not further the bases for termination provisions. The operating and performance standards of each of the utility's firm capacity standard offers, as modified here, are sufficient to ensure that the QFs signing these offers will be capable and dependable. It is this very group of energy producers which should be encouraged to sign offers and should not be discouraged by unreasonable contract requirements.

Staff's suggestions regarding the application of PG&E's probationary period to capacity reductions has been covered in the previous section. Whether this period also should be applied to failures to maintain certain governmental authorization is not clear. We unfortunately have no evidence to suggest how long it would take to cure such defects. Because other parties had different views and suggestions regarding provisions requiring the maintenance of governmental authorization, we will consider this entire issue in the next decision on these applications.

Because of the various formulas and notice periods to be used in the utilities' termination provisions, the staff's recommendation that the utilities give clear examples in their offers of the operation of their provisions has merit. Each utility's standard offer for firm capacity should, therefore, include such examples.

Finally, we note that a reduction, as opposed to a total termination, of capacity under a firm capacity contract is more similar to a modification of the contract than to a complete breach. Such a capacity reduction should not result in a complete termination of the agreement. The principles adopted above, however, are properly applied to such a reduction. The utilities' termination provisions should, therefore, clearly reflect their application to the amount of capacity being reduced, in the manner adopted by PG&E and SDG&E.

b. <u>Simultaneous Purchase and Sale</u>

In D.82-01-103 we specifically addressed a QF's ability to convert from a simultaneous purchase and sale of energy to a sale of surplus only. The concept of simultaneous purchase and sale is a regulatory convention which allows a QF simultaneously to sell its own generation to the utility while purchasing its requirements from the utility. A QF would elect this option for economic reasons (i.e., the retail rate being less than the avoided cost).

While we approved such conversions, we also imposed certain restrictions to ensure that the utility and its ratepayers are compensated for any lost capacity costs. In particular, we agreed with PG&E that such a conversion would be conditioned on reasonable notice and full compensation. The conversions were limited to once per year and were subject to the following:

> "...The QF that receives capacity payments under simultaneous purchase and sale through a long-term contract and converts to sell surplus will face termination provisions."
> (D.82-01-103, at page 86.)

Many of the QFs participating in this proceeding took issue with both the limitation on the frequency of a conversion and the application of termination provisions to that change. Given our directives in D.82-01-103, however, these issues would more properly have been raised in a petition for rehearing of that order. We further believe that the decision, which is now final, properly addressed these issues. We find no basis for changing our previous conclusions.

We note also that the termination provisions which we have adopted in this order apply to both reductions in capacity as well as a complete termination of the agreement. PG&E's contract language governing the conversion from simultaneous purchase and sale to a surplus-only sale properly directs that a QF which undertakes such a conversion will be subject to termination provisions only for the amount by which the contract capacity is reduced. Specifically, the language of PG&E's contract, Section A-3.2 of Appendix A, reads: "If the energy sale conversion results in a capacity sale reduction, the provisions in Appendix D [PG&E's termination provisions] shall apply." We believe that this approach complies with OIR 2 and should be used by all three utilities.

c. Notice of Termination in <u>As-Available Contracts</u>

Edison's standard offer for as-available capacity states in Section 5:

> "This agreement shall become effective on the date of execution by the parties and shall remain in effect until terminated by Seller upon one year prior written notification given to Edison, which notification shall not be given prior to the date the generating factility is operating and delivering energy to the point of interconnection."

Edison justifies the inclusion of this notice requirement as necessary for determining the number of as-available producers which, in the aggregate, will be ready and willing to sell energy and capacity in any particular year.

We reject Edison's argument. The inclusion of such a provision in an as-available contract is unreasonable and in conflict with D.82-01-103. In that order we specifically stated that termination provisions were not appropriate for offers to purchase as-available power. The staff in its brief correctly summarizes the reasoning behind this conclusion:

> "...Unlike firm capacity QFs, a QF with an as-available contract is under no obligation to supply power to the utility, and it is paid only for the power it delivers. The QF's incentive to produce power is its economic self-interest, not contractual penalties. Since a QF who terminates its contract is indistinguishable from a QF who chooses not to produce while maintaining its contract, staff sees little purpose in Edison's notice requirement." (Staff concurrent brief, at page 62.)

We will, therefore, direct Edison to delete the notice of termination requirement from its standard offer for as-available capacity.

B. Capacity Prices

D.82-01-103 provides that QFs which sell electricity to the utility shall be eligible for payments based on the costs that the utility system avoids through purchases of such QF power. For the standard offers which are the subject of these compliance hearings, the costs that utilities avoid by purchasing increments of QF power are defined on the basis of a short run incremental or marginal cost methodology. Short-run marginal costs on the utility system consist of two components: shortage costs and operating costs. QFs receive energy payments for reducing utility marginal operating costs. QFs receive capacity payments for reducing marginal shortage costs on the utility system. This section evaluates the capacity prices which PG&E, Edison, SDG&E propose to pay QFs pursuant to D.82-01-103.

In D.82-01-103 we determined that QFs should receive capacity payments for both as-available and firm sales to the utility. This conclusion reflects the fact that QF output on either basis will increase the amount of electricity available to the utility, increase reserve margins, and make the possibility of outages less likely. Stated another way, QF power will lead to avoided shortage costs and QFs should be paid accordingly.5/

Shortage costs on the utility system at any given time can be defined as the expected cost of an outage at that time or, more precisely, the probability of an outage multiplied by the customer costs associated with an outage. As the probability of an outage increases during peak demand periods (when reserve margins are diminished) and decreases during off-peak periods, shortage costs will be higher during daily and seasonal peak periods and lower during off-peak periods.

5/ As noted earlier, firm and as-available QFs do receive somewhat different payments which reflect the added value of the firm sources.

Shortage costs can also vary on an annual basis, as reserve margins change from one year to the next.

Because customer outage costs are very difficult to measure on a direct basis, we adopted a proxy for shortage costs in D.82-01-103 and D.82-04-071. Specifically, we used the capital costs of a utility combustion turbine peaking plant, a low-capital cost plant built to meet reliability needs alone, as a proxy for annual shortage costs. This annual shortage cost amount has been allocated disproportionately to peak and semi-peak hours within the year to reflect shortage cost variations.

There is a very clear reason for adopting the capital costs of a combustion turbine as a proxy for annual shortage costs. If utilities manage their reserve margins correctly, they will pursue capacity-related investments up to the point where the last unit of investment costs the same on an annual basis as annual expected customer outage costs or shortage costs avoided through such investment. The combustion turbine represents the marginal capacity-related investment. If marginal shortage costs exceed marginal capacity-related investment costs, ratepayers will benefit by more investment which lowers the higher shortage costs by reducing the likelihood of outages. If marginal shortage costs are less than the costs of marginal capacity-related investments, then investments should be reduced, reserve margins allowed to shrink, and shortage costs to increase. Overall, the utilities will seek to equate avoided shortage costs with the annual cost of the marginal capacity-related investment (represented by the combustion turbine). The combustion turbine is therefore a reasonable proxy for the equilibrium shortage cost value that will exist on the utility system on average.

In the petitions for rehearing of D.82-01-103 the utilities argued that annual shortage costs will sometimes differ from the equilibrium or average combustion turbine capital cost level. Therefore, they argued, QF capacity prices should vary accordingly. In D.82-04-071 (pp. 2-3), we concluded that while the use of the combustion turbine proxy "is consistent with an incremental fuel cost that will for some time be based on oil and gas", a more precise refinement of the proxy which "varies capacity payments based on the probability of loss of load, perhaps using reserve margins, would be desirable".

D.82-04-071 clearly specified, however, that as-available capacity payments were to be based on the combustion turbine and that any refinements of the proxy were to be considered only in future general rate cases. The language of D.82-04-071 was less clear as to when refinements of the proxy would be considered in the case of firm capacity payments. As noted earlier, pursuant to an ALJ ruling, the utilities were allowed to introduce into these compliance hearings methodologies for adjusting the combustion turbine proxy and the QF firm capacity payments that are derived from that proxy. Basically, the utilities' methodologies are aimed at reflecting year-to-year variations in reserve margin levels which lead to year-to-year variations in shortage costs.

The two issues before us now are (1) whether or not PG&E, Edison, and SDG&E used accurate combustion turbine costs in calculating their as-available and firm QF capacity prices and (2) whether in the case of firm capacity prices, the utilities' proposed adjustments of the combustion turbine proxy should be adopted.

1. The Cost of the Combustion Turbine

Firm and as-available capacity prices in all of the utilities' filings are based directly or indirectly on the capital costs of a combustion turbine. The accuracy of these plant cost estimates is thus an important issue in this proceeding. The threshold question here is whether or not the combustion turbine costs should be uniform between utilities, based on a "generic" combustion turbine plant, or whether the costs should be more utility-specific.

We agree with the utilities that combustion turbine costs can vary between utilities due to different financing costs, environmental requirements, and locational factors. The costs of meeting a shortage through construction of peaking capacity will legitimately vary from one utility to the next because of these factors. However, it is much less clear why other factors that are not utility-specific in nature, such as forecasts of general economic indices, should vary in the combustion turbine costs estimates adopted for PG&E, SDG&E and Edison. We do not agree with the utilities that these broader indices need to vary by utility to reflect differing corporate assumptions. If corporate assumptions about such items as inflation and oil prices had to be followed, staff and other parties could not challenge such assumptions as they normally do in other proceedings such as the utilities' general rate cases. We will allow for utility-specific cost variation where it is shown to be warranted, but will strive for uniformity in the case of assumptions that are not clearly utility-specific in nature.

The estimation of combustion turbine capital costs and the application of such costs to capacity prices in contracts of different lengths requires estimates of numerous factors. These include combustion turbine construction costs, fixed charge rates, plant economic life and book life, fixed operations and maintenance costs (O&M), fixed administrative and general costs (A&G), fuel inventory costs, escalation rates, and discount rates. We will consider these factors in the context of each of the utilities' capacity price filings.

a. Edison

Staff and IEP argue that Edison's basic combustion turbine capital cost, $415/kW, is too low, and argue instead for $450/kW based on Edison's CFM-IV filing and staff's "generic" combustion turbine estimate. Edison argues that the $415/kW number is an estimate based on a January 1, 1982 on-line date and that its CFM-IV estimate was a "rounded" version of a combustion turbine with a June 1, 1982 on-line date. The latter is a higher figure because of inflation. We find that Edison's estimate is reasonably close to staff's "generic" turbine estimate and that it is consistent with the combustion turbine proxy that we adopted for rate design purposes in Edison's test year 1982 general rate case. Also, the January 1 number is more consistent with the average year rate base fixed charge rate methodology that is used by Edison and staff. Therefore, we will adopt $415/kW for 1982 combustion turbine capital costs for Edison.

To spread the combustion turbine capital costs to capacity prices over the years of various QF contracts, including the single year as-available contract, fixed charge rates and constant dollar factors are used. These factors depend in part on the economic life that is assumed for the combustion turbine. Edison argues that a 30-year economic life should be used. This period, in Edison's view, is a realistic estimate of the useful life of such a plant. Staff and IEP counter that Edison uses a 23-year assumption to depreciate its own plant and that a 30-year assumption is inconsistent with this approach and artificially disadvantages QFs.

We have previously considered this issue in D.93887 (p. 175), in which we decided that PG&E should use a 24-year combustion turbine useful life assumption consistent with its own depreciation schedules. Edison's assumption is inconsistent with D.93887 and with PG&E and SDG&E filings in this proceeding. We will adopt the 23-year economic life for Edison's capacity prices. Any change by Edison in its own depreciation schedules to more closely reflect its estimate of useful plant life made in this proceeding should be considered in Edison's general rate case.

Escalation and discount rates also affect the combustion turbine-based capacity price stream for different contract lengths and different start-up dates. The 15% discount rate used by staff and Edison, based on an estimate of Edison's incremental cost of capital, is reasonable. The escalation rates for capacity prices, fixed O&M, and fuel prices used by staff are reasonable. Edison argues that these latter staff assumptions are at odds with its corporate assumptions used for planning purposes in general. We believe that these are factors which are not utility-specific in nature. The use of the staff assumptions here is consistent with adoption of the same assumptions for PG&E's and SDG&E's combustion turbine cost estimates discussed below.

The staff fuel price assumption is only important for combustion turbine cost estimation if the combustion turbine fuel inventory cost escalates over the life of the unit. Edison contends that this fuel inventory cost should not be escalated. In effect, Edison assumes that gas will always be available for use in the turbine over the life of the unit and that the liquid fuel inventory will never be used. Staff and IEP argue that the inventory costs should be escalated, using their oil price escalation assumptions.

Staff argues that gas may not always be available and that even if it is, it may not be the cheaper fuel option. Therefore, the inventory will be used and replaced over time. The staff escalation rate assumption implicitly assumes that the inventory will be replaced annually.

We conclude that the most reasonable assumption lies between the staff and Edison positions. It is unlikely that the inventory will be replaced annually and such an assumption may overstate avoided fuel inventory costs, particularly since Edison normally uses first-in-first-out (FIFO) fuel inventory accounting. The assumption that the inventory will never be turned over, however, is equally unrealistic. We will adopt an escalated fuel inventory using 50% of the staff's annual escalation rates, reflecting partial annual use of the inventory over time.

Another item of contention between Edison, staff, and IEP, is the proper amount of fixed A&G costs that should be capitalized as a part of the combustion turbine cost. Edison uses 1% of the capital costs of the plant as a measure of levelized annual A&G costs over the life of the plant. Staff uses 1% of the capital costs of the plant as a measure of the first year A&G costs and escalates this figure over the life of the plant. The result is equivalent to a 1.6% levelized A&G figure. Staff argues that Edison used the 1% escalating figure in its most recent general rate case. IEP argues that at 2% levelized figure should be used, citing a 1982 staff study that showed Edison's A&G costs to be a 2% or higher percentage of fixed plant. Edison in this proceeding repudiated its rate case marginal cost A&G assumption and questioned the applicability of the staff calculations in Exhibit 16 upon which IEP relied in making its argument.

It is apparent from the record here that the relationship between A&G costs and fixed plant additions is not fully understood. We agree with Edison, however, that the degree to which A&G costs are actually avoided by QF purchases is problematic. Under these circumstances, a conservative approach is appropriate in prescribing the A&G measure. We will therefore adopt Edison's 1% levelized figure for A&G.

Staff, IEP, and Edison also disagree on the appropriateness of Edison's "differential fuel credit". Edison includes in its combustion turbine capital costs a measure of the increased fuel costs that occur, above the system marginal operating cost, when the combustion turbine is actually operated. We agree with IEP and staff that Edison should account for this increased marginal operating cost not in the combustion turbine capital cost, but in its estimate of the system marginal operating cost. In other words, the costs of operating the combustion turbine should be reflected in QF energy prices, not capacity prices.

Finally, we note that Edison in its brief argues that the staff's fixed charge rate in Exhibit 71 differs from Edison's rate for reasons other than the varying fixed charge rate assumptions of the two parties. This circumstance appears to be purely a computational problem. We will direct Edison in this order to file capacity prices that are based on combustion turbine costs that reflect our preceding conclusions about costs.

b. <u>SDG&E</u>

SDG&E's capacity price filing utilizes a combustion turbine capital cost of $400/kW. Staff argues, as it did in the case of Edison, that $450/kW is a more appropriate figure. Staff found the SDG&E estimate to be too low because of inadequate allowance for cost overrruns, pollution control requirements, new site costs and other factors. SDG&E counters that its allowance for cost overruns is consistent with historical experience, that it has included requisite pollution control costs, and that it is unrealistic to include new site costs given that SDG&E would be much more likely to add combustion turbines at existing sites.

IEP argues that the combustion turbine cost used in SDG&E's test year 1982 rate case (A. 59788), $618/kw, should be used for capacity prices here. SDG&E states in Exhibit 37 that the rate case figure reflects a 500MW combustion turbine development at a new site with an anticipated baseload mode of operation. The OIP-2 filing reflects the avoided costs of a 50MW peaking unit at an existing site.

We will adopt SDG&E's capital cost estimate of $400/kw. It is reasonably close to Staff's "generic combustion turbine" estimate and the reasons for its being lower, such as the use of existing plant sites, are justifiable on utility-specific grounds. We agree with SDG&E that their rate case cost estimate is based on a plant type that does not sufficiently reflect the marginal peaking capacity investment that we have chosen for the shortage cost proxy.

Staff and SDG&E differ on the proper escalation rates to be used for capacity costs, fixed O&M, and fuel prices. Consistent with our discussion of the Edison combustion turbine costs, we will adopt the staff estimates. We do, however, agree with SDG&E that more recent, lower inflation rates should also lead to a lower estimate of the incremental cost of capital that is used in the fixed charge rate. We will revise the staff figure of 16.5% down to 15.5%. This approach is consistent with the estimate used for Edison while also taking into account the different credit ratings of the two utilities.

The record is silent on whether SDG&E included an A&G cost in its combustion turbine cost estimate. We agree with staff, which argues in its brief that an A&G component should be included. SDG&E A&G costs should be commensurate with those adopted for Edison.

Staff and SDG&E are in agreement on fuel inventory costs, fixed O&M costs, and the economic life of the plant. We will adopt these figures. For the purposes of calculating capacity prices, SDG&E will be directed to utilize combustion turbine costs which conform to the foregoing conclusions.

c. PG&E

PG&E filed capacity prices that were based on combustion turbine capital costs of $770/kw. This estimate was taken from PG&E's most recent general rate case. (D. 93887). Staff argues that, unless the Commission uses a generic combustion turbine cost, it would be simpler to use the rate case number used by PG&E. IEP concurs that the rate case estimate should be used, but offers several suggestions about various combustion turbine costing assumptions should the issue be considered anew.

We do consider it to be important to examine the combustion turbine cost assumptions in this decision rather than merely accepting estimates from previous rate cases. We indicated in D.82-01-103 and D.82-04-071 that the combustion turbine was a reasonable proxy for shortage costs. The purpose of these compliance hearings was to examine the adequacy of the method by which the utilities translated this concept into capacity prices.

From the perspective of the record in this proceeding, in which three utility filings were considered together, PG&E's capital cost estimate from its rate case appears to

~~vary from that of the other utilities by an~~ unreasonable amount. This variance is wider than one could reasonably expect from utility-specific factors alone. Therefore, we will not adopt this estimate and will instead adopt the staff's generic combustion turbine capital cost of $450/kw for PG&E. This estimate is closer to our adopted capital costs for Edison and SDG&E.

We agree with IEP that if one combustion turbine cost estimate from PG&E's rate case is examined and updated here, other assumptions should be examined as well. We will therefore not adopt staff's use of the rate case escalation and discount rates. Instead, we will adopt for PG&E the more recent estimates for capacity price, O&M, and fuel price escalation that staff has recommended for Edison and SDG&E. We will adopt a 15.0% incremental cost of capital which is consistent with our adopted discount rate assumptions for Edison and SDG&E.

IEP notes that the rate case combustion turbine estimate did not include a fuel inventory cost. To ensure consistency, we will direct PG&E to include a fuel inventory cost component equivalent to that adopted for Edison.

We find that the assumptions used by PG&E in its rate case estimate as to the economic life of the turbine, fixed O&M costs, and fixed A&G costs are reasonable. We will direct PG&E to derive capacity prices based on combustion turbine cost assumptions adopted in the foregoing discussion.

2. <u>Adjustments in the Combustion Turbine Proxy for Firm Capacity Payments</u>

As noted earlier, in these compliance hearings the utilities proposed that their firm capacity prices be based on methodologies that adjust the combustion turbine shortage cost proxy for year-to-year variations in reserve margins and reliability. Staff supported these metholologies in concept, but criticized several specific elements of the methods. Also, staff argued that because of the uncertainty over the accuracy of the methods and the related assumptions, a "floor" on downward adjustments of the combustion turbine proxy should be adopted. The floor capacity price in any contract year would be 50% of the annual combustion turbine cost.

IEP, Occidental, the State Energy Task Force and other QFs opposed the utilities' methodologies, arguing that they were given inadequate opportunity to examine these methods in the hearings. Further, the limited examination that did take place showed that the utilities' methodologies were seriously flawed.

We will consider all of the parties' positions in the context of each utilities' proposed shortage cost methodology.

a. <u>PG&E</u>

PG&E proposes that the combustion turbine proxy be set as the maximum annual shortage cost and that this value should be adjusted downward in years in which reserve margins are forecasted to be above target levels. PG&E proposes that this downward adjustment be based on an Energy Reliability Index (ERI). The ERI is derived from PG&E's Generation Reliability and System Simulation Model (GRASS). The ERI is a probabilistic measure of the expected size and frequency of reduced electric energy deliveries which are forecasted to result from generation capacity limitations in future years. An ERI number is derived for each future year in which firm QF capacity prices must be calculated. In years in which PG&E's reserve margins are expected to be smaller than or equal to target levels (with loss of load probabilities greater than or equal to the target one day in ten years), the ERI adjustment factor is set at 1.0 and the QF capacity price is set at the full combustion turbine cost level. In years in which reserve margins are atypically large the ERI adjustment factor is calculated as the ratio of the ERI in the large reserve margin year in question to the ERI in a base year when reserve margins are at their target levels. This ratio, a number less than one, is multiplied by the full combustion turbine cost to produce a QF capacity price for that year which is less than the full combustion turbine proxy.

We believe that PG&E has presented an innovative methodology for measuring shortage costs. However, we agree with other parties in the proceeding that the method is underdeveloped and suffers from several important flaws in both concept and actual application.

One important conceptual flaw is that the ERI method is biased because it allows for downward adjustments in the shortage cost proxy when reserve margins are above target levels, but does not allow for upward adjustments in years in which reserve margins are below target levels. We agree with Occidental and IEP that such upward adjustments should be a part of any precise shortage cost methodology. Clearly, as noted earlier, the combustion turbine is a proxy for the equilibrium or average shortage cost value. Actual shortage costs will vary above and below the equilibrium value, due to the "lumpiness" of powerplant capacity additions. This circumstance is especially true in the case of shortage costs for the near term, a time frame in which unexpected demand increases cannot be met with new plant additions because of the lead time associated with new plant construction. In calculations of longer term shortage costs, an upper limit equal to the cost of a combustion turbine proxy may be appropriate, depending on the precision on forecasts.

A second conceptual problem with the PG&E method is that it treats many of the uncertain factors that affect future reserve margins in a deterministic fashion. It is a basic tenet of supply planning that the greater the uncertainty about future demand levels, plant start-up dates, and plant maintenance requirements, the greater the reserve margin "insurance premium" that is needed. For PG&E's assumptions not to reflect the uncertainty about these factors is to understate reserve needs. As PG&E has stated in its CFM-IV filing:

> "The explicit inclusion of uncertainty will always require a larger reserve capacity to maintain the same level of reliability, given the assumed certain outcome falls in the middle of the range of possible outcomes...PG&E's (supply) planning reflects this consideration." (Ex. 68).

We agree with Occidental that, if uncertainty leads PG&E to increase its estimates of shortage possibilities and reserve needs for its own supply planning purposes, PG&E, to be consistent, should also take this uncertainty into consideration in calculating capacity payments to QFs. If this approach is not used, QF capacity value will be understated.

Another shortcoming related to the development of the PG&E methodology is PG&E's failure to perform a sensivity analysis on the ERI model to investigate whether or not the ERI results would be drastically altered by small changes in input assumptions. PG&E has argued that the ERI results are not likely to be sensitive. Staff points out in its brief, however, that the evidence indicates otherwise. The relatively small adjustment PG&E made during the proceeding in its input assumption about load management achievements led to a relatively large change in the ERI result. In general, the lack of sensitivity analysis casts doubt on the validity of the ERI results.

Apart from these weaknesses in the PG&E shortage cost methodology itself, numerous questions arose during the hearings about the application of the methodology to the standard offers. It appears that PG&E used several erroneous input assumptions when it calculated EPI adjustment factors and derived its proposed QF capacity prices. Start-up dates for the Diablo Canyon nuclear plant and the Helms pumped storage facility were assumed to be January 1, 1982 and August 1, 1983 respectively, both of which are incorrect. Future forced outage rates on plants such as Rancho Seco and Contra Cost 1 were assumed to be much less than the outage rates experienced historically. The derating of the Pittsburgh 7 plant was not taken into account. Demand forecasts were based on older, higher oil price assumptions and therefore were probably understated. Demand may have also been understated, in turn understating shortage costs, because the forecast load management goals were assumed to have been fully achieved.[6/]

Forecasts of future reserve margin levels are obviously extremely difficult undertakings which involve many assumptions about future loads and resources. PG&E's assumptions were not adequately substantiated in the hearings. Many of the assumptions appear to have the effect of understating future shortage costs and QF capacity payments.

PG&E offered two revisions of its assumptions which lessen this problem to a certain degree. First, the extent of its assumed load management achievement was reduced. Second, PG&E offered to make a retroactive upward revision in QF capacity payments if the Helms and Diablo start-up dates were not realized.

6/ We note in passing that while load management goals should not be included, we do not agree with Staff and IEP that load management should not be included at all. Rather, we concur with Edison's argument in its brief that load management, utility resources, and QF power must be considered, to the extent feasible, simultaneously, not sequentially, in the estimation of future shortage costs. However, load management assumptions must be conservative, especially when estimating the impact of voluntary programs.

We consider the retroactive payment revision undesirable because it does not signal QFs prospectively about the value of their future performance. More importantly, we do not consider these two proposed revisions of PG&E's capacity input assumptions are sufficient to alter our conclusion that the EPI input assumptions result in understating shortage values and QF capacity payments.

Because of the methodological flaws and questions surrounding PG&E's input assumptions we will not adopt PG&E's shortage cost methodology. While we will not preclude new proposals in future hearings aimed at refining the shortage cost proxy, at this time we conclude that PG&E's firm capacity payments, like its as-available payments, should be based on the basic combustion turbine proxy, using the combustion turbine cost assumptions adopted previously in this decision.

b. SDG&E

SDG&E proposed a shortage cost methodology which is similar to PG&E's. In SDG&E's methodology, an annual "probability of need" is calculated using SDG&E's production simulation model, PROMOD. The probability of needing capacity varies from year to year as reserve margins vary. The maximum value of the probability of need is 1.0, and in such years QF capacity prices are set equal to the full combustion turbine. In years when reserve margins are above target levels, the probability of need is less than one and the full combustion turbine capacity price is adjusted downward accordingly.

In its brief SDG&E claims that certain criticisms of PG&E's method do not apply to SDG&E's methodology. In particular, SDG&E claims that it uses more realistic input assumptions in its reserve margin forecast. For example, forced outage rates on existing units are assumed in the PROMOD forecast to be similar to those experienced historically by the plants. Forced outage rates on new units are assumed to be higher than those experienced by other utilities with plants of the same type, to provide "a cushion against error". Finally, SDG&E asserts that it <u>has</u> taken into account the impact of more recent, lower oil price forecasts in its demand forecast and reserve margin forecast.

In evaluating SDG&E's shortage cost method, it is immediately apparent that this method includes certain flaws similar to those enumerated for PG&E. For example, a basic methodological shortcoming is that the shortage cost proxy can only be adjusted downward and can never exceed the equilibrium or average combustion turbine level. Further, an increasing shortage cost trend through the years can, under SDG&E's method, never be followed by any downward trend, even if this situation more accurately reflected reserve margin changes. Finally, with respect to input assumptions, it appears that uncertainty about new plant on-line dates was not taken into consideration and that, for example, an unrealistic assumption was made about SONGS 2 being fully available by the beginning of 1982.

It is difficult to evaluate the extent to which SDG&E's method suffers from flaws in data and methodology because SDG&E's shortage cost method was not sufficiently examined during the hearings. SDG&E changed its methodology late in the proceeding after staff had already undertaken its evaluation of SDG&E's capacity prices. SDG&E did not adequately substantiate its new method and the input assumptions that it used. The ALJ ordered SDG&E on October 15, 1982 to provide data on its input assumptions and its methodology in keeping with our decision in OII-26 which set up certain requirements to substantiate evidence in cases involving computer simulations. Such information was to be provided to staff and the State Energy Task Force during the briefing schedule. However, both staff and the State Energy Task Force indicate in their briefs that they had still not received the data at the time briefs were completed in mid-November.

Because SDG&E's methodology appears to have certain flaws similar to those found in PG&E's approach and because SDG&E did not adequately substantiate its proposed refinement of our adopted shortage cost proxy, we will not adopt SDG&E's proposal. Instead, we find that the basic combustion turbine cost is an adequate proxy for shortage costs and should be used for SDG&E's firm capacity payments. This finding is consistent with D.82-01-103, with SDG&E's as-available capacity price, and with our previous conclusions relating to PG&E's firm capacity price. As we noted in the case of PG&E's method, our adoption of the basic combustion turbine shortage cost proxy for firm capacity prices does not preclude the further consideration of more precise shortage cost methodologies in future hearings.

c. <u>Edison</u>

Edison's proposed refinement of the combustion turbine proxy represents a different methodology than that proposed by PG&E and SDG&E. Rather than adjusting the combustion turbine proxy to reflect the results of computer simulations of likely future reserve margins, Edison proposed that QF capacity prices should equal the price of wholesale market capacity contracts between 1982 and 1985 and full combustion turbine costs thereafter.[7] The wholesale market price that Edison primarily relies on for 1982-1985 QF capacity prices is the emergency capacity price in the California Power Pool Agreement. Secondarily, Edison states that this price is also supported by the Edison - California Department of Water Resources Contract and the Principles of Interconnected Operations for the Navajo and Four Corners Power Projects. Edison contends that its $24/kW/yr 1982-1985 capacity price for QFs is quite generous. Edison points out that it would only pay such a price for emergency purchases under its wholesale contracts if it were to take emergency power for the entire 12 months of the year. In Edison's view, such a circumstance is very unlikely.

The State Energy Task Force contends that the wholesale contracts that Edison relies upon for its 1982-1985 QF capacity price are complex energy and capacity exchange agreements that involve shared services. Because it is a part of such a package, the State Energy Task Force claims the emergency power price cannot be isolated and used by Edison in developing its shortage costs.

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7 The combustion turbine costs are based on the value of deferring a combustion turine over the length of the contract. This is a slightly different approach for deriving the levelized price for different contract periods than that used by PG&E. PG&E applies a real economic carrying charge to an annually inflating turbine cost and levelizes the resulting escalating payment stream. Both approaches should lead to the same result given the same assumptions and either is acceptable.

The State Energy Task Force's claim has merit. It is quite possible, for example, that, within these reciprocal exchange agreements, emergency power services are mutually underpriced by the parties to the agreement. If this is so, taking the California Power Pool Agreement as an example, then a QF which allows Edison to avoid a capacity purchase from PG&E would be avoiding Edison's capacity purchase costs and PG&E's costs which are not covered in the purchase price. The fact that the price of emergency power in the California Power Pool has not changed since 1964 despite inflation and narrower reserve margins makes this possibility quite plausible.

Edison argues that it is necessary to focus on the costs that it actually avoids when it does not make a wholesale contract purchase, not any additional value of the service that may not be reflected in the purchase price (or any additional cost that may be avoided by another utility elsewhere). However, if we return to the California Power Pool example, it can be seen that such a focus may not yield accurate avoided cost price signals. If PG&E and Edison were to base QF capacity prices on a mutually underpriced reciprocal exchange service, the additional costs that QFs actually avoid, but are not reflected in the price, would never be included in QF capacity prices of either utility. This possibility weakens the validity of Edison's argument.

A second criticism of the Edison method is that the wholesale contract price is not necessarily a reasonable proxy for the utility's marginal shortage cost. The existence of wholesale contract capacity does not indicate whether or not the contract capacity represents the marginal resource. Is the contract the most expensive increment of capacity on the system (more expensive than other capacity contracts or load management programs of other resources)? Is the contract the resource that would be avoided if QF power was accepted? Even within the narrow sphere of wholesale contracts alone, it is not clear that emergency power contracts are the type of contracts that would be displaced by constant purchases of firm QF power. Under emergency power agreements, infrequent use of the service is normally assumed by the seller. Constant firm purchases might lead to a different type of wholesale agreement and price. The latter might be a better measure of avoided cost.

A clear conclusion on the accuracy of using wholesale emergency contracts as the marginal shortage cost proxy would require more evidence about all of Edison's wholesale contracts, company-owned resources, and load management programs. We are hampered in our analysis, as we were in the case of SDG&E, by Edison's inadequate offering of data during the proceeding. For example, the State Energy Task Force submitted to Edison a data request on August 27 asking Edison for information about its capacity price methodology based on wholesale contracts. The information which was sought included (1) the contracts that were used to set the \$24/KW/yr 1982-1985 price and (2) other contracts that exist, but were not used to set the QF capacity price. This information is exactly the type required to ascertain the validity of the price calculation and the degree to which the contracts upon which that calculation is based represents the marginal resource in the context of all such contracts.

Edison responded on September 21 that "much of the specific information sought is proprietary in nature". During subsequent hearing dates, however, it because apparent that the contracts in question are public documents filed with the Federal Energy Regulatory Commission.

In view of the doubts cast on the wholesale capacity price resulting from the reciprocal exchange arrangements upon which it was based, and in view of the inadequate showing indicating that the chosen contract price was an accurate reflection of Edison's actual avoided shortage cost, we cannot adopt Edison's proposed methodology. As we have done in the case of PG&E's and SDG&E's firm and as-available capacity price and Edison's as-available capacity price, we will adopt the capital cost of the combustion turbine as a reasonable proxy for shortage costs for Edison's firm capacity prices. This conclusion does not preclude the adoption of a more precise shortage cost methodology for Edison in future hearings and does not preclude the use of wholesale capacity prices in such a methodology.

3. <u>Conclusions on Capacity Prices</u>

In D.82-04-071 we concluded that: "At present the gas turbine is the best surrogate we have for capacity and it is consistent with an energy payment based on oil or gas." (Mimeo, page 3.) We reaffirm that conclusion today. In reaffirming this conclusion we do not posit that the combustion turbine is the most exact measure of avoided shortage costs. Given the evidence in this proceeding we essentially face a choice between imperfect measures of avoided shortage costs: (1) the utilities shortage cost measure, which have been inadequately substantiated and shown to be biased downwards in certain respects and (2) the combustion turbine proxy which is also an inexact measure and has been argued to be biased upwards. Given this imperfect choice and the uncertainty surrounding avoided shortage costs, we choose the combustion turbine alternative because it gives a stronger incentive to cogenerators and small power producers. This is proper, we believe, because these power sources bring with them many important benefits to ratepayers which are difficult to quantity and not captured in the avoided cost calculation.

We will direct the utilities to file as-available and firm capacity price schedules based on the capital costs of the combustion turbine, using the combustion turbine cost assumptions adopted earlier in this decision. We also conclude that the possibility of developing a more refined shortage cost methodology which accounts for year-to-year variations in reserve margins is worth exploring further. The issue will be raised in PG&E's and SDG&E's current rate cases, and in Edison's five-year forecast energy price offer (A.82-04-46). Any revisions to capacity tables will be made prospectively for new contracts. They will not apply to QFs which have already signed firm capacity contracts.

Energy Payments

A. General

D.82-01-103 stated that energy payments should be derived from a utility's shortrun operating costs, reflecting the variable cost of providing an additional unit of electricity. In calculating the energy prices, the intent of the decision was "to capture as accurately and timely as possible the current marginal energy costs incurred by the utility." (D.82-01-103, page 31.) The decision stated that the current practice was to use the previous three-month oil costs and forecasted incremental heat rates. In a later decision (D.82-11-087), the Commission made a revision and adopted prospective fuel prices in the event that gas was the marginal fuel.

The parties in the case representing small power producers generally were concerned by the unpredictability of the energy prices and by their inability to verify the calculation of these numbers. Various suggestions were made to provide more certainty, including proposals to include formulas for energy in the contract, to use average annual incremental heat rates, to establish price floors, and to levelize the energy payments over time. In general, the utilities have rejected such proposals as being unworkable, overly burdensome, or unresponsive to changing conditions.

We resolve these conflicting concerns by ordering utilities to provide as much certainty as is possible in their contracts and procedures without undermining the basic concept of using the avoided energy price applicable to these standard offers. The risks QFs take relating to energy prices in these offers are not unlike the risks in a competitive spot market. For example, small power producers take the risk of changing utility fuel costs in future years as they influence the marginal energy rate. It is also consistent for incremental heat rates to fluctuate since, in fact, these rates will vary depending on future supply and demand conditions in utility operations.

SDG&E argues that the Commission's program to develop small power production "significantly reduces the QF's obligation to compete in an open and free market for the sale of QF generated power." Noting that "the QF receives a payment for its power from a regulated environment instead of an open market", SDG&E argues that "[t]his substantial reduction of the risk in a QF's operation, compared to an open market business operation, is an unprecedented preferential benefit provided by the State of California to unregulated businesses." (Brief, page 3.) We disagree. As described above, QF prices behave similarly to those in a competitive supply market, and the pricing does create considerable risks for QFs, not unlike those in a competitive market. In fact, our concern is that the administratively established prices in this program may create <u>more</u> risks for QFs than would open market prices. Unlike a free market, administrative changes can affect basic pricing methodologies, not just changes in supply and demand conditions. We agree with QFs that these risks should be mitigated whenever possible.

One major administrative risk implied by the proposed contracts is the possibility of a change in pricing policy by future Commissions. Specifically, as the contracts currently are written, some future Commission could order that a new pricing policy be adopted with prices derived at less than avoided costs. We do not believe such discretion is appropriate. While a future Commission may have the prerogative to implement pricing policy changes prospectively for new small power contracts, QFs which have already built projects should received payments derived from the pricing methodology in existence when the project was built. Otherwise, far too much price uncertainty will exist. Accordingly, we will order that utilities include a provision in all their standard offers before us which assures QFs that they will receive payments throughout the life of the specific project derived from the utility's full shortrun avoided energy costs, as approved by this Commission. This requirement will ensure that a framework is established firmly, with prices derived from a utility's full avoided costs. Since these contracts are viewed as reasonable, per se, the utility's expenses for such purchases can be assured (D.82-01-103, page 24). Such a provision does not add to utility risks as suggested by the utilities.

The second major administrative risk for small power producers not present in a competitive market is the model used for calculating the avoided cost payment. Unlike most markets in which buyers and sellers meet at arm's length to establish prices (i.e., the stock market or a commodity market), the prices established for small power producers are derived from models in possession of the utilities as approved by this Commission. Not surprisingly, the small power producers are skeptical of this arrangement and would at least like these models to be more explicit and understandable. We agree that this concern is significant. We will therefore require that utilities present, in detail, the assumptions behind their energy price calculations and that QFs have an opportunity to critique the assumptions in the utility models.

To provide greater certainty and clarity, some QFs suggest that an energy price formula be written into the QF contract. We do not find such an approach to be feasible. The pricing formula is highly complex and could not suitably be incorporated. Furthermore, while QFs should have the certainty that their prices will reflect the utilities marginal variable costs, the actual model for calculating such costs may become more refined in the future. A specific formula would preclude such refinements. By clearly establishing that prices should reflect the utilities' shortrun avoided costs in the contract and by giving QFs an opportunity to review and comment on the utilities' calculations, we believe sufficient certainty is provided as to how these payments are to be derived.

B. Determination of Energy Prices

While the policy to establish prices from the utilities' shortrun marginal operating costs is generally understood, there remains a considerable debate on how to calculate those rates. The utilities' marginal operating costs vary almost continuously, and at least at this time the metering technology does not exist to signal prices so frequently. As a result, the average marginal cost applied for a particular time period must be used. One issue concerns how long this periods should be and under what conditions the prices may be adjusted from the average marginal rates. A second major issue concerns whether the methods used by utilities for calculating the marginal operating costs for a particular period are accurate.

We generally resolve these issues in two ways. First, to the extent possible, this decision addresses the specific concerns raised by the parties relating to the calculation of energy prices. However, it is clear from this proceeding that not all of the potential issues relating to the calculation of energy prices were addressed. We expect that the parties will want to offer further comments and refinements in the future. Therefore, in addition to resolving many specific issues here, we will provide a procedure by which QFs and other parties can provide comments in the future. We do not provide this procedure as a forum to relitigate issues, but to allow new issues to surface. Small power producer pricing remains in an evolutionary stage, and we have no doubt that issues will continue to arise about how prices should be established within the guidelines established in D.82-01-103.

1. Incremental Heat Rates

One significant issue in this case was how often a utility's incremental heat rates should be revised for determining prices to small power producers. Incremental heat rates, which reflect the efficiency with which utilities can burn fuel at the margin, are one component in the determination of the marginal cost of electricity. IHRs vary depending upon what plants are in operation at any particular time.

Currently, incremental heat rates are determined biennially in the utilities' general rate cases, with heat rates varying by time of day and season. These incremental heat rates are used for determining the prices during the two-year period after a rate case is completed, using fuel costs which are updated quarterly (for PG&E and SCE) or three times a year (for SDG&E). If actual incremental heat rates deviate from the projected average heat rate developed in a rate case due to hydro conditions or any other reason, this change is not reflected in the quarterly prices.

QFs generally favor using the average annual heat rate approach because it provides more price stability. Administratively, QFs also object that utilities may deviate from the average annual heat rate when it suits their interests (e.g., when hydro conditions are favorable and the incremental heat rates generate relatively low prices). PG&E suggests that average annual heat rates be used now, but suggests that projected actual year heat rates (accounting for hydro conditions) might be desirable in the future to more closely reflect actual shortrun operating costs.

By separate petitions for modification filed September 10, 1982, CMA and Imotek, Inc. asked the Commission to clarify D.82-01-103, and find that utilities should use average annual incremental heat rates for determining avoided costs, as determined in the most recent rate case. The petitioners argue that actual year heat rates create instability in QF prices and are unverifiable. We will respond to this petition in this opinion.

We resolve that, for now, average year incremental heat rates should be used in the determination of avoided costs as determined in the utilities' rate cases. We have no procedure at this time for verifying more current estimates, and we do not think it appropriate to adopt more frequent estimates without giving parties the opportunity to comment on the methodology. However, we conclude that actual year incremental heat rate calculations would be preferable because they more accurately reflect actual marginal operating costs. QFs that are able to respond to the higher price signal in a dry year, for example, would have a greater incentive to provide energy when it is more needed. On the other hand, small-hydro producers whose fluctuations in electric supply parallel those of utility hydro plants are likely to be overpaid using average hydro years, as in the current method, since they would be likely to produce relatively little in low hydro years (when actual avoided costs are relatively high) and relatively more in high hydro years (when actual avoided costs are relatively low).

While we are adopting average annual heat rates now, we will ask utilities by September 30, 1983 to make proposals for a procedure to use projected actual year incremental heat rates. The utilities in their proposals should clearly set forth how they intend to forecast hydro conditions which would then be used to forecast actual year heat rates. The IHR forecasts probably should be made in the spring to take into account hydro conditions. We will not adopt any proposal until parties have had an opportunity to review and comment on it. Utilities should not deviate from the current two-year review procedure until the deviation has been expressly approved by this Commission.

Another issue raised by staff was how to handle new plants that come on line which effect IHRs. D.82-01-103 at page 31 states that IHRs determined in rate cases should not include new power plants because both the operating dates and operational characteristics of new plants are generally unknown. However, should a new facility begin operation between cases, staff recommends that the IHRs be revised in an ECAC proceeding. We will adopt this suggestion.

Both SDG&E and Edison argue that they should not file incremental heat rate data since such data are not explicit outputs of their models. The utilities use probablistic models, which predict the likelihood of a particular plant being on line in any particular hour, and estimate the expected average electricity price based on that model. At some cost the models could be adapted to produce incremental heat rates as outputs. We agree with small power producers that such information would be valuable and should be provided. Current and expected heat rate data would provide QFs with the ability to determine more realistically prices in future periods. Such costs currently are included as utility administrative expenses. Such accounting would appropriate in this case.

2. Marginal Fuel Costs

Many of the parties were concerned with the fuel costs used in determining the avoided energy costs. Concerns were raised whether forecasted fuel prices, prior period fuel prices, or retrospective prices should be used and how the determination of themarginal fuel at any particular time would be made.

Currently, the energy prices are set by utilities at the beginning of a quarter, and QFs can anticipate that payments will be based on those prices throughout the quarter, except for SDG&E which establishes rates three times a year in ECAC. Adjustments are not made at the end of the quarter to reflect actual conditions during that quarter. This procedure gives QFs a clear and predictable price upon which they can base operations for future periods, but it also results in a relatively less accurate determination of the shortrun operating costs than if prices were established retrospectively with fuller knowledge of what actually occurred. Some suggestions were made in the proceeding that the prices be adjusted at the end of the quarter to reflect actual prices paid during the quarter for fuel. Payments to QFs would be retroactively adjusted at the end of the quarter to coincide with actual fuel prices paid during that quarter.

We conclude that the current procedure of prospectively establishing prices is preferable. This procedure gives QFs a clear price signal from which to determine its operations for the upcoming quarter. In reaching these prospective determinations, we will attempt, as accurately as possible, to project the fuel mix which will occur in the future quarter. Any variations in the projected price should likely be as high as they would be low, and deviations should cancel out over time. Retrospective adjustment would undoubtedly create significant controversy, be cumbersome and destabilize the market for small power producers.

In D.82-11-087, the Commission ordered the utilities to use current natural gas prices for the determination of prospective avoided operating costs, but to continue to use oil into inventory when oil is the marginal fuel. We will continue to adopt this approach for now, though we would consider refining the oil and natural gas price numbers to include projections instead of current prices in the future. For now, we conclude that projecting oil and natural gas prices would be unduly complicated.

A major controversy in this case was the determination of whether oil or gas is the marginal fuel at any particular time. In recent months, oil in inventory has been more expensive than natural gas. QFs have been concerned that utilities have been burning oil while claiming that natural gas is nearly always the marginal fuel. In response, utilities argue that they must burn oil in inventory either to avoid underlift payments or for various other reasons which preclude oil from actually being the marginal fuel. IEP questions the utilities' assertions and suggest, as a simplifying assumption for calculation, that oil should be presumed to be the incremental fuel on any day it represents 10% of the generation mix. Staff in evaluating this issue concludes that oil is not generally an avoided fuel at this time, and that the 10% oil mix assumption is arbitrary.

It appears that the question of whether oil or gas is the marginal fuel will involve specific issues that vary in each quarter. Accordingly, our approach will be to ask each utility to file its projected marginal fuel mix in each quarter and allow parties an opportunity to critique these projections. Each quarter the utilities should also submit information on their actual experience in the prior quarter. Any decisions reached by the Commission to modify these prices should provide guidance for future quarters.

Much time was spent in this proceeding on the issue of whether Edison avoided oil in the first quarter of 1982 or whether it primarily avoided gas. As some of the parties point out, the resolution of this issue has implications for future quarters as well. Edison argues that while oil was burned during this past year, it was not marginal because it was burned either for testing or to avoid underlift charges in Edison's long-term contracts.

Edison's response appears to be accurate. We conclude that the basic conceptual problem is that the oil prices used in the determination of avoided costs are based on long-term contract prices and therefore may not reflect current fuel markets. When a utility avoids burning oil, it may not be able to avoid the full long-term contract price paid for it when it must either sell the oil on the spot market at a price less than the contract price or refuse to take additional oil from its supplier to control inventory and pay underlift charges. It appears to be reasonable that the avoided cost therefore should be based either on the spot market price or the long-term price less the underlift charge. The utilities apparently simply assumed that the avoided cost of oil was less than gas when underlifts are taken into account and therefore assumed that their avoided fuel was natural gas. Given the current oil and gas mix and the current price relationships, such a simplifying assumption seems reasonable.

We cannot agree that oil should be presumed to be the incremental fuel when it is 10% of the daily use. Such a standard would be arbitrary. We are sympathetic to a more detailed analysis of marginal oil use in future proceedings in the determination of the marginal energy costs. The issue of whether oil or gas is the marginal fuel is complex and will depend upon specific circumstances. This issue is one that we would expect to arise in future proceedings to review the utilities's price offers, which we describe below.

Another issue in the proceeding is whether the fuel used to warm-up facilities should be viewed as marginal and calculated in the avoided cost payment. We agree with staff that the cost of warm up fuel cannot be included at this time since it is unclear that such fuel is avoided as a result of purchases from QFs.

Another issue relating to fuel costs is whether SDG&E should use its G-61 commodity rate for determining the avoided natural gas costs for its electricity utility generation. The staff and others recommend that the higher GN-5 rate be used, which is the rate established for pricing between SDG&E's gas and electric departments. The G-61 rate is the general commodity rate which SDG&E purchases all of its gas requirements.

We conclude that staff's position is correct. When the electric department of SDG&E purchases electricity from a QF, ratepayers avoid electric production with costs derived from the GN-5 rate for the purposes of calculating SDG&E's electric rates. By establishing QF prices using the GN-5 rate, ratepayers are indifferent between purchases from QFs and utility generation, consistent with avoided cost principles. To base prices on the G-61 rate would result in an underdevelopment of QF resources, leading to uneconomic use of natural gas in utility boilers. Use of the G-61 rate would also result in an inconsistent pricing system between QFs in Edison's and SDG&E's territory. Edison purchases gas from Southern California Gas Company at the GN-5 rate.

Utilities argue that fuel is not avoided when it is being burned to maintain spinning reserves. By definition, we agree. In the event fuel is being burned in the facility to allow it to be available for future periods, the availability of QFs does not allow the utility to avoid that fuel.

It is evident that the determination of the marginal fuel costs for utilities will remain a controversial subject and that the parties will want to be involved in reviewing the utilities determinations. As CMA points out, the dollars involved are large and will undoubtedly grow in the future as the QF market develops. It is important that we establish an understandable and balanced forum in which parties can review and comment on these prices.

We will therefore adopt the following procedure. In the case of PG&E and Edison, we will order the utilities to file prices for energy payments one month prior to the quarter in which the energy prices apply. These prices and a detailed description of the assumptions used to derive them should be filed with the Commission. In addition, the utility should make available this information to interested parties for their review. In the event either staff or the interested parties object to the proposed prices, a motion to adjust the price may be filed to the Commission. In the motion, the specific concern must be stated and a recommended resolution suggested. The Commission will decide what further action to take depending upon the nature of the motion.

In the event no action is taken by the Commission by the time a quarter begins, the utilities' prices will go into effect. These prices may be adjusted upward and applied retrospectively in the event the Commission later reaches a determination that the prices posted were too low. However, no downward adjustments will be made retrospectively to avoid pricing uncertainty for QFs.

SDG&E currently is establishing its prices three times a year in ECAC proceedings. We will continue this procedure. Like Edison and PG&E, SDG&E should spell out the assumptions used in deriving its numbers.

We expect utilities to forecast as accurately as possible their actual marginal operating costs for future quarters, including their expected fuel mix, and to provide their assumptions to interested parties. We expect that as we reach decisions relating to various issues regarding price in the future, utilities will incorporate those decisions. Over time the utilities' procedures should become fairly understandable and routine. We have no doubt that parties will question utility determinations, and we expect to review them carefully. However, we do not intend to relitigate issues in proceeding after proceeding.

For this procedure to work, it is incumbent upon utilities to present their information clearly and understandably. QFs must be able to understand how prices are being determined to make intelligent investment decisions. We expect that utilities will keep all data relating to QF prices well organized in a central place to permit parties to review the calculations.

C. Adjustments to Energy Prices

A number of issues were raised in the proceeding regarding adjustments to energy prices for various purposes. We consider these issues in this section.

1. Avoided Transmission and Distribution Costs

Little or no evidence was presented in this proceeding demonstrating that QFs allow utilities to avoid transmission and distribution system costs. Therefore, none are included in the avoided cost payments filed by the utilities. We find this approach to be appropriate at this time.

2. Variable Operations and Maintenance Costs

There was general agreement that variable operating and maintenance costs should be included in the avoided cost determinations. However, PG&E and SDG&E include these costs in their energy payments while Edison includes them with its capacity payment. For consistency, we will order that these costs be included as part of the energy payment. In the regular price filings, the assumptions regarding the derivation of variable O&M should be included.

3. Line Losses

D.82-01-103 ordered applicants to "include costs or savings from line losses in the aggregate" (Ordering Paragraphs 6(a) and 8(e)). The Commission created an exception that line losses will be examined individually for "projects one MW or larger developed at sites remote from load centers."

The record in this proceeding indicates that this issue inadequately studied by the utilities to determine appropriate loss rates. PG&E's study does not differentiate between remote sites and other QFs, while SDG&E and Edison have not undertaken a study at all. In the absence of such a study, we will adopt a loss factor of 1.0 to be applied by all utilities for all QFs at this time. This resolution essentially assumes that QFs line losses are equal to utility plant losses, which seems reasonable lacking better information. We will also adopt the suggestion that loss factors be established for three voltage levels.

Additionally, we will adopt the staff position that studies be performed by utilities to determine the aggregate line losses of QFs. PG&E should report on this subject in 6 months and SDG&E and Edison in one year.

The record indicates that at this time adjustments for line losses for remote sites is beyond our current capabilities. We will therefore suspend the use of specific line losses for remote sites until the problem is better understood. As part of the studies required of utilities, we will ask for an analysis of how to identify remote QFs and how to reflect a different loss rate. Until such studies are performed, remote QFs will not have individual line losses adjustments.

PG&E suggests that individual line losses should be established. This approach would not comply with D.82-01-103. The individual determination of line losses would create great complexity and would very likely result in frequent disputes between the utility and QFs. Aggregate line loss determinations are appropriate at this time.

4. Transformer Losses

An issue was raised about whether transformer losses should be included in the avoided cost payment, and if so, how that loss should be determined. The staff suggests an appropriate solution: simply place the meter on the utility side of the transformer, thereby automatically accounting for the transformer losses in the meter reading. We will adopt this recommendation. If a QF desires to have a meter on its side of the transformer, it may negotiate a transformer loss rate with the utility.

D. Refusal to Purchase and the Hydro Spill Rate

One of the more complex issues relating to energy payments regards the periods in which a utility may refuse to purchase from QFs or offer lower prices to reflect current conditions in the utility system. As described earlier, price is established for electricity purchases for a time period based on projected average marginal costs. The actual avoided costs incurred will vary throughout the period, varying around the average established.

There are certain conditions in which the actual avoided costs deviate so significantly from the average that special treatment may be warranted. In particular, D.82-01-103 found that when the utility actually incurs costs by purchasing energy from a QF (a "negative avoided cost" condition), the utility should have the right to curtail QFs. In D.82-04-71, the Commission also concluded that when a utility must spill water over its own hydroelectric facilities in order to purchase from QFs, a lower price is appropriate. The decision did not, however, permit a lower price to be established during periods when economy energy is purchased or when avoided costs are positive. Anticipated economy purchases were to be averaged in the avoided cost applied for the entire time period.

Allowing utilities to pay lower rates or curtail customers unexpectedly creates significant complications for QFs because of unwieldy notification requirements and price instability. It is also very difficult to establish what the lower rate during periods of economy energy or hydro spill should be. For this reason we previously decided to very narrowly define the period and to include the expected economy energy purchases in the average rate for the entire period. What is lost in precision is gained in administrative workability and price certainty.

The parties in this proceeding suggest alternatives and refinements to this approach. Certain QFs suggest fixed limits on the number of hours that they can be curtailed or offered the lower hydro spill rate. A number of proposals were made to limit the applicability of curtailment and hydro spill conditions. Staff proposed that a 100-hour limit be established for curtailment and hydro spill conditions, while the IEP suggested that a total of 200 hours be applied to both. Staff suggested that in the event the QF is required to curtial more than 100 hours, it should be paid for the additional hours based on what it would have produced in event curtailment had not been invoked. Staff argues that it is unlikely that QFs would be curtailed for longer than 100 hours in any event, and the added certainty about being paid makes the provision worthwhile. Utilities, in general, oppose such restrictions in the contract, arguing that such provisions would be inconsistent with D.82-01-103 and could tend to overpay QFs.

Procedurally, we agree with the utilities that restrictions on the number of hours that curtailment and hydro spill conditions apply would be inconsistent with D.82-01-103 and D.82-04-071. Those decisions attempt to very narrowly define the conditions in which either term could be applied in order to reduce uncertainty for QFs. However, lacking any evidentiary basis, neither placed limits on the application of those provisions.

While we are sympathetic of the concerns of QFs that they must understand what the outside limit of the application of these provision could be, we have no evidentiary basis to determine what that limit should be. We will, therefore, order utilities to undertake studies to estimate the maximum probable limit for hydro spill and curtialment conditions likely to occur in future years in order to provide QFs with more certainty about the likelihood of those provisions being imposed. These studies should be submitted to the Commission and provided to parties within 3 months. Based on these studies, we will entertain proposals to modify D.82-01-103 to establish limits in the contracts for the refusal to purchase and the hydro spill conditions.

1. The 600-Hour Curtailment Option

Utilities have suggested that as an option, QFs be offered a curtailment provision that applies to periods of economy energy purchases and which includes a 600-hour annual limit. While we welcome and encourage such an offer being available as an option, the offer itself is outside the scope of these compliance proceedings. The standard offer should be based on the negative avoided cost and hydro spill conditions outlined in the original decisions. We will view the 600-hour curtailment provision option as a nonstandard contract for now because we have not reviewed the details of how the curtailment provisions would work or how they would affect the marginal energy prices. We support the concept, because it would provide greater pricing precision, and permit greater economy energy purchases.

2. Implications of Curtailment on Firm Capacity Payments

An issue arose on how curtailment provisions relate to the firm capacity provisions. We conclude that QFs should be presumed to be available during curtailment periods and should be eligible for any ouput payments (even if not actually provided) since the QFs are being curtailed by the utilities. We will therefore adopt the staff's suggestion that the contracts be modified to reflect these conclusions. This resolution comports with D.82-01-103 at page 81, which states that QFs signing firm capacity contracts should be paid for capacity during times of non-purchase.

3. Internal Use of Energy During Curtailment

Certain parties suggest that cogeneration facilities operating under simultaneous purchase and sale contracts be permitted to use energy internally in the event of curtailment. We reject this proposal. As staff points out, curtailment is likely to occur in periods of extremely low demand, and any further reduction in demand caused by internal use of electricity would likely reduce the value of curtailment and be costly for the utility. If a QF agrees to sell all of its output under simultaneous purchase and sale, the output should be subject to curtailment as for any other QF.

4. Notice Requirements

In order to assist QF planning, longer notice requirements for curtailment were suggested. D.82-01-103 established notice guidelines. We do not see any reason to change them here. Of course, utilities should give as much notice as possible of impending curtailment.

E. Price Floors and Levelized Payments

Suggestions were made in this proceeding to establish a price floor for energy payments and to levelize energy payments. Both of these suggestions are clearly outside the scope of these compliance hearings. The levelized payment option was addressed and rejected in D.82-01-103 (Pages 55-56) and the floor concept was not discussed at all.

If a floor price were established, some reduction of the energy price would be necessary to remain within the avoided cost concept. The floor reduces QF risks and creates the possibility that at some point the floor price paid might be above avoided cost. In return for this security, a lower price during the rest of the time is appropriate. We would encourage utilities to negotiate nonstandard contracts with floors or levelized payments if QFs are interested.

Further Modifications of Contracts

This decision is the first in these applications. We will issue later in 1983 another decision regarding other issues raised in this proceeding which may result in further modifications to these contracts.

QFs interested in signing contracts between now and the time of a final decision may be reluctant to sign until the Commission resolves the remaining issues. To relieve this uncertainty somewhat, we will give QFs who sign contracts between the effective date of this decision and the time a final offer stemming from these compliance hearings takes effect the opportunity to switch from the interim contract to the final contract. QFs may not switch from one standard offer to another, but may adopt the final version of the particular offer signed.

Findings of Fact

1. The California Public Utilities Commission has a continuing interest in promoting the development of cogeneration and small power production facilities.

2. By D.82-01-103 in Order Instituting Rulemaking (OIR) 2, each electric utility was required within 45 days of the effective date of that order to file standard offers to be made to qualifying facilities for (a) as-available energy and capacity based on a short-run avoided cost methodology, (b) firm capacity based on a short-run marginal cost methodology, and (c) energy and capacity provided by QFs below 100 kW in size.

3. The offers required by D.82-01-103 were included in the applications which are the subject of this order.

4. Evidentiary hearings were held with respect to A.82-03-26 (PG&E), A.82-03-37 (Edison), and A.82-03-78 (SDG&E) to determine each of these utilities' compliance with the requirements of D.82-03-103 and other related orders in OIR 2; the reasonableness of provisions included in the utilities' offers, but not specifically addressed in the OIR 2 decisions; and the factual bases for the prices contained in each of the standard offers.

5. Consideration of issues recited in Finding 4 above for A.82-03-62 (Sierra Pacific Power Company), A.82-03-67 (Pacific Power & Light Company) and A.82-04-21 (CP National Corporation) have been deferred until the resolution of A.82-03-26, A.82-03-37, and A.82-03-78.

6. An additional issue properly addressed during the evidentiary hearing was the appropriate methodology for determining capacity costs, based on the shortage cost concept, under a utility's firm capacity standard offer. Revisions of the methodology for calculating a utility's as-available capacity payment is reserved for the utility's general rate case as specified in D.82-04-071.

7. For a decision to be issued in this proceeding prior to the end of 1982, only certain issues raised during the hearings and in briefs can be addressed. The remaining issues which are not resolved by this order will be considered as early as possible in 1983.

8. The issues chosen for consideration in this order relating to the utilities' capacity and energy payments will provide QFs with sufficient options to make the economic decisions necessary for determining the merits of proceeding with or continuing a particular project.

9. Payments for as-available capacity do not reflect any value for contract length, notice, termination or sanctions, since such provisions are not part of an as-available offer.

10. Firm capacity is viewed as an increase in the utility's supply of electricity with corresponding performance standards, termination provisions, and sanctions.

11. D.82-01-103 requires that (a) firm capacity payments reflect availability during system peak periods including such factors as dispatchability; reliability; contract duration, termination, and sanctions; scheduling of outages; and availability during emergencies; (b) the value of each of these factors are to be calculated based on standards comparable to performance standards the utility would impose on its own plants; (c) the sum of each of these factors are to be included in the resulting capacity value; (d) a QF that exceeds operating standards normally expected of utility plants is to be able to earn a higher capacity payment; and (e) when resource limitations exist to reliable operations, plant capacity factor may be a better measure of reliable operation than availability.

12. Each of the utilities proposed a different approach to performance standards in their firm capacity standard offers.

13. Three general types of performance standards have been proposed in the utilities' filings—the first based on a level of peak period availability (PG&E's Option 1), the second based on a level of peak period output (PG&E's Option 2, SDG&E's Option 2, and Edison's single option), and the third requiring only a certain contract duration with no specific requirement for peak period output or availability (SDG&E's Option 1).

14. PG&E's Option 1 availability standard requires the QF to be dispatchable and available during emergencies and to maintain a certain level of peak period reliability. The option also imposes termination provisions for nonperformance and allows for scheduled maintenance.

15. As modified herein, PG&E's Option 1 is reasonable and in compliance with D.82-01-103.

16. PG&E's Option 2 output standard ensures reliable operation during peak periods and emergencies and, like Option 1, imposes termination provisions for nonperformance with an allowance for scheduled maintenance.

17. As modified herein, PG&E's Option 2 is reasonable and in compliance with D.82-01-103.

18. An 80% summer peak hour availability or output requirement under PG&E's Options 1 and 2 is reasonable and, with PG&E's revised reduction of payments provisions, is a sufficiently flexible measure of QF performance.

19. SDG&E's Option 2, an output-based performance offer, requires only a 50% level of output during all peak and semi-peak hours. This standard of performance is not commensurate with the

utility plant avoided by QF purchases, which plant would have a higher level of peak period availability than 50%. Additionally, termination provisions are not imposed for failure to meet this standard.

20. SDG&E's Option 2 is not in compliance with D.82-01-103.

21. Edison's output-based performance standard fails to focus on peak-period availability, with a 50% performance level which is too lenient for the peak period and an emergency availability requirement which is too stringent and places too much emphasis on one aspect of peak period availability.

22. Edison's output based performance standard is not in compliance with D.82-01-103.

23. SDG&E's Option 1, which merely requires a contract commitment for a specified period with no peak period availability or output requirement, fails to reflect the performance standards for firm capacity offers required by D.82-01-103 and is not an option to purchase firm capacity as defined by that order.

24. SDG&E's Option 1 is not in compliance with D.82-01-103.

25. It is necessary for the utilities to refile their standard offers for firm capacity to conform to D.82-01-103.

26. To comply with D.82-01-103, all utilities must file standard offers with payments options based on both a QF's availability and energy production. PG&E's Options 1 and 2 serve as basic models for such options, as modified consistent with this decision.

27. To achieve overall compliance with D.82-01-103 and this order, the following principles should be incorporated in any utility's firm capacity standard offer:

a. Dispatchability must be defined to give a utility the right to require only increases, not decreases, in a QF's operation. Any other definition permits unwarranted and unresonable interference with a QF's operations. Dispatchability need not be limited to on-and midpeak periods and emergencies if an approach like that used in PG&E's Option 1 is adopted.

b. Each payment option must provide for payments in excess of a utility's capacity costs for QFs whose performance exceeds that of the utility's plants. To receive the higher payment, the QF's performance must consistently exceed the minimum level of availability of the peaking unit used as a proxy to calculate the utility's shortage costs. A peak period availability or capacity factor in excess of 85% is a reasonable performance standard to require of QFs entitled to capacity payments in excess of 100% of the shortage cost proxy. An 80% reliability factor is reasonable for offers based on 100% of a utility's capacity costs. For an availability option which permits the higher payment, a more certain measure of the QF's dispatchability is required than presently provided in PG&E's Option 1 in order to determine whether and at what level the QF actually exceeds the utility plant's operation.

c. PG&E's proposal with respect to the treatment of small hydro QFs whose payments are based on the five dry year average, but are experiencing a "drier" year than that average, is reasonable and should be adopted for all utilities with one modification. It is reasonable to permit hydro QFs to be paid during the "drier" year for the amount of capacity, if any, actually delivered to the utility. Capacity payments should resume at the contract price when hydro conditions once again reach the level used to determine the capacity rating.

d. Essential elements of a scheduled maintenance standard are a reasonable allotment of days for both routine maintenance and major overhauls, sufficient notice to aid utility system planning, and appropriate timing to avoid periods of greatest demand on the utility system. The scheduled maintenance allowance should be uniform for all utilities and should include all of the elements and requirements listed in the discussion of scheduled maintenance in this decision.

e. PG&E's revised approach for reducing payments under either its availability or energy output payment options for nonperformance is reasonable and should be adopted in all utility standard offers for firm capacity. This modified approach permits payments for capacity actually delivered during a 15-month probationary period with the potential of the original payment level being reinstated or the QF's capacity derated at the end of the period depending on the QF's performance during the peak months. The difference between the contract capacity and the reduced capacity is appropriately subject to contract termination provisions. For the capacity actually delivered during the probationary period, an allowance or credit for forced outages at the level otherwise specified in the utility's standard offer should be included. No retroactive payment is necessary.

28. No provision is required in a firm capacity standard offer to permit as-available capacity payyments during a start-up period. A QF seeking as-available capacity payments during the period before its firm capacity operations commence has the option of signing a short-term as-available capacity contract.

29. Each of the utilities properly responded to D.82-01-103 by including termination provisions in their firm capacity standard offers.

30. The utilities' termination provisions must be reasonable.

31. Termination provisions should encourage QFs to fulfill their contractual obligations, provide reasonable certainty of the consequences of termination, and make the utility and its ratepayers whole.

32. There is no reason for termination provisions to vary greatly between utilities with respect to the basic requirements of such provisions.

33. Liquidated damage clauses, which limit damages to the amounts or formula prescribed in the clause and provide a party with advance knowledge of how the damages for termination will be calculated, are desirable and reasonable for inclusion in every utility's standard offer for firm capacity.

34. It is reasonable for the liquidated damage clause to cover reimbursement of unearned capacity payments. The utilities' methods for calculating this reimbursement are reasonable, with the exception of the need for a uniform imposition of and standard for interest to be charged on the amount refunded.

35. The published Federal Reserve Board three months Prime Commercial Paper rate (plus 50 points for SDG&E) is currently used to calculate interest on the utilities' various accounts and is a reasonable rate to apply to the repayments required of a QF whichterminates its firm capacity contract with prescribed notice.

36. It is reasonable for the utilities to include liquidated damage clauses to cover the replacement costs associated with QF termination and to provide a reduction or elimination of those damages for a QF which gives the prescribed advance notice of its termination.

37. Each utility's standard offer for firm capacity must distinguish between those QF's terminating with prescribed notice, for which replacement damages are eliminated, and those which do not.

38. The specific notice required for termination should depend on the amount of capacity being terminated and may be utility-specific. The proposals of SDG&E and PG&E are reasonable; Edison should be required to prescribe a table similar to those proposed by PG&E and SDG&E varying the length of notice according to the amount of capacity being terminated.

39. For QFs terminating without prescribed notice, it is reasonable for all of the utilities to adopt PG&E's approach to calculating the damages to be added to the refund of overpayments, with one modification. The adopted damage formula should reflect the time needed, as reflected in the notice table, to replace the lost capacity.

40. The utilities' calculation of damages can properly refer to future capacity prices.

41. Any requirement that a QF provide evidence of its ability to make potential termination payments is burdensome and unreasonable.

42. It is reasonable for each utility's firm capacity standard offer to include examples of the operation of its termination provisions.

43. A reduction in capacity should not result in a complete termination of an agreement; however, the termination provisions can be applied to the amount being reduced.

44. D.82-01-103 clearly provides for a limitation of one year to conversions from the simultaneous purchase and sale of energy to the sale of surplus only and for the application of termination provisions to QFs which undertake such a conversion.

45. It is reasonable for a utility to provide that a QF which undertakes the conversion referred to in Finding 44 above be subject to termination provisions only for the amount by which the contract capacity is reduced. This approach complies with D.82-01-103 and the application of termination provisions to capacity reductions. It should be used by each of the utilities.

46. Edison's inclusion of a notice requirement for the termination of an as-available capacity contract is unreasonable, is in conflict with D.82-01-103, and should be deleted. That decision specifically states that termination provisions are not appropriate for offers to purchase as-available power.

47. For the standard offers that are the subject of these compliance hearings, D.82-01-103 requires that avoided costs be defined according to avoided short-run marginal costs. One component of this definition, avoided shortage costs, should be the basis for firm and as-available capacity payments.

48. In D.82-01-103 and D.82-04-071 the Commission adopted the capital costs of a combustion turbine as a proxy for shortage costs.

49. D.82-04-071 specified that as-available capacity payments are to be based on the full cost of the combustion turbine and that any refinements of this proxy would only be considered in future general rate cases.

50. Pursuant to an ALJ ruling, the utilities were allowed to introduce into these compliance hearings methodologies which adjust the full combustion turbine shortage cost proxy for firm capacity payments.

51. Combustion turbine costs vary from one utility to another because of different financing costs, environmental requirements, and locational factors.

52. It is not reasonable for estimates of combustion turbine costs calculated at a given time to vary from one utility to another on the basis of general economic indices.

53. Edison's combustion turbine capital cost estimate of $415/kW for a January 1, 1982 plant on line date is reasonable.

54. Staff's 23-year plant economic life for the Edison combustion turbine estimate is reasonable and consistent with D.93887.

55. The escalation and discount rates used by staff for the Edison combustion turbine cost estimate are reasonable for the purposes of making that estimate.

56. Combustion turbine fuel inventory costs will escalate over the life of the plant and, for the purposes of the Edison combustion turbine cost estimate, 50% of the staff oil escalation rate is a reasonable figure to use for fuel inventory escalation.

57. Edison's fixed administrative and general costs assumption is reasonable for purposes of calculating its combustion turbine cost estimate.

58. The increased system marginal operating costs resulting from the operation of the combustion turbine are more accurately reflected in avoided energy costs rather than avoided capacity costs.

59. SDG&E's 1982 combustion turbine capital cost estimate of $400/kW is reasonable for the purposes of QF pricing.

60. The SDG&E incremental cost of capital for the purposes of combustion turbine cost estimation is 15.5%.

61. Accurate combustion turbine costs for SDG&E include fixed administrative and general costs and staff's proposed escalation rates.

62. Staff and SDG&E are in agreement on fuel inventory costs, fixed O&M costs, and plant economic life assumptions for combustion turbine cost estimation. These assumptions are reasonable.

63. The staff's 1982 generic combustion turbine capital cost of $450/kW is reasonable for the purposes of PG&E's QF pricing.

64. The escalation rates used by staff for the Edison and SDG&E combustion turbine cost estimation are also accurate rates for PG&E's combustion turbine costs.

65. A 15.5% incremental cost of capital is a reasonable assumption for combustion turbine cost estimation for PG&E.

66. An accurate PG&E combustion turbine cost will include a fuel inventory cost commensurate with that found reasonable for Edison.

67. Plant economic life, fixed operation and maintenance costs, and fixed administrative and general cost assumptions adopted for combustion turbine cost estimation in D.93887 are reasonable for the purposes of the combustion turbine cost estimation used for PG&E's QF pricing.

68. PG&E proposes to adjust the combustion turbine shortage cost proxy used to calculate firm capacity prices to reflect year-to-year variations in reserve margins, using PG&E's Energy Reliability Index (ERI) methodology.

69. The ERI methodology is an innovative approach to measuring shortage costs.

70. The ERI methodology is conceptually flawed and biased downward because it only allows for downward, and not upward, adjustments in the annual shortage cost proxy.

71. A precise shortage cost methodology will allow for upward adjustments in the equilibrium shortage cost when loss of load probabilities are greater than the target level.

72. The ERI methdology is conceptually flawed and biased downward because it treats uncertain factors such as plant start up dates and plant maintenance requirements in a deterministic fashion in estimating future shortage costs and reserve needs.

73. The absence of a sensitivity analysis casts doubt on the validity of ERI results.

74. PG&E utilized several erroneous input assumptions when it used the ERI methodology to derive firm capacity prices.

75. The accurate estimation of future shortage costs requires, to the extent it is feasible, the simultaneous rather than sequential consideration of load management programs, utility resources, and QF power.

76. PG&E's proposed revisions of its firm capacity price methodology to use different load management assumptions in the estimation of future ERI numbers and to include retroactive capacity payments if Helms pumped storage plant and Diablo Nuclear power plant startup dates are not realized do not remove the downward bias in its ERI-based capacity prices.

77. For the calculation of firm capacity prices, SDG&E has proposed a shortage cost methodology that adjusts the combustion turbine proxy for year-to-year variations in reserve margins.

78. The SDG&E method is conceptually flawed because it only allows for downward adjustments in the annual shortage cost proxy, not upward adjustments.

79. The SDG&E method is flawed because it does not allow year-to-year increases in shortage costs to be followed by decreases in those costs.

80. In calculating firm capacity prices using its shortage cost method, SDG&E did not adequately allow for utility plant start up date uncertainty and included an unrealistic assumption about the 1982 availability of the SONGS 2 nuclear plant.

81. SDG&E did not adequately substantiate its shortage cost methodology nor its input assumptions.

82. Given the same input assumptions, calculation of annual combustion turbine costs using either a plant deferral concept or a real economic carrying charge concept should lead to the same result and either is reasonable.

83. For the calculation of firm capacity prices, Edison has proposed a shortage cost methodology that bases 1982-85 shortage costs primarily on wholesale emergency capacity prices in the California Power Pool Agreement and secondarily on the Edison-California Department of Water Resources Contract and the principles of interconnected operations for the Navajo and Four Corners Power Projects.

84. The wholesale contracts that Edison utilizes for 1982-85 firm QF capacity prices are complex energy and capacity exchange agreements that involve shared reciprocal services.

85. The fact that the price of emergency capacity in the California Power Pool has not changed since 1967 despite inflation and narrow reserve margins makes more likely the possibility that this agreement is a mutually underpriced reciprocal transaction that is not an accurate proxy for avoided shortage costs.

86. Edison did not adequately substantiate its claim that the emergency capacity price is the marginal resource avoided by firm QF capacity purchases.

87. The shortage cost methodologies for firm capacity prices proposed by PG&E, SDG&E, and Edison in these compliance hearings are unreasonable.

88. Further hearings are required before more refined shortage cost methods can be adopted.

89. The capital cost of the combustion turbine is a reasonable proxy for shortage costs to be used for as-available and firm capacity prices.

90. It is reasonable that energy prices in the as-available, firm and less than 100 kW offers should reflect as nearly as possible a utility's marginal variable operating costs.

91. The current standard offers create unnecessary risks for QFs that energy prices in some future period might not be derived from a utility's avoided costs.

92. It is reasonable for each contract to include language that energy prices will be derived from the utilities' marginal variable operating costs, as approved by the Commission, throughout the life of the project.

93. It is not feasible to include an energy price formula in standard price offers.

94. It is reasonable for interested parties to have the opportunity to review and comment on the utilities' calculation of energy prices.

95. The determination of energy rates derived from the utilities' marginal operating costs is in an evolutionary stage. Refinements will emerge over time.

96. It is reasonable for utilities to use average year estimates of incremental heat rates, as determined in rate cases, for the derivation of energy prices until the Commission approves a more refined methodology.

97. Actual incremental heat rate and fuel use data filed regularly would be useful for the evaluation of future period energy prices.

98. It is reasonable that the input of new plants which affect the incremental heat rates be determined in an ECAC proceeding.

99. Projected energy prices are less precise than retrospective calculations, but provide more pricing certainty for QFs.

100. Current natural gas prices more closely reflect marginal operating costs than do historical costs.

101. Oil may be burned to control inventory or for testing without being a marginal fuel.

102. Fuel used to warm-up facilities is not necessarily avoidable.

103. SDG&E avoids natural gas at the GN-5 rate, not the G-61 rate.

104. Fuel is not necessarily being avoided when used to maintain primary reserves.

105. No evidence now exists that transmission and distribution costs are avoided by QF purchases.

106. It is reasonable that variable operating and maintenance costs be included explicitly in the energy price derivations.

107. Insufficient data exists on line losses at this time. A reasonable assumption is that losses are equal to the line losses of utility plants, thus implying an aggregate line loss factor for QFs of 1.0, except for secondary line losses, which can reasonably be assumed to be the utility's marginal line losses.

108. Until sufficient evidence is presented by utilities for the identification and valuation of losses from remote sites, the loss for all QFs for energy can reasonably be established at 1.0.

109. Transformer losses need not be established if the meter is on the utility side of its transformer.

110. Limited evidence exists on the maximum probable number of hours utilities might invoke either for refusals to purchase or hydro spill conditions.

111. Restricting the number of hours for hydro spill or refusal to purchase is inconsistent with D.82-01-102 and D.82-04-071.

112. The option to pay QFs a higher capacity payment in return for up to 600 hours of curtailment during periods of economy energy purchases, while desirable, is an issue outside the scope of these compliance hearings.

113. Internal use of energy by QFs on simultaneous purchase and sale during curtailment would reduce demand and possibly exacerbate load problems the utility is seeking to solve through curtailment.

114. A levelized or price floor energy option is outside the scope of these proceedings.

Conclusions of Law

1. The Commission should contiunue to encourage the development of qualifying cogeneration and small power production facilities.

2. The standard offers of PG&E, Edison, and SDG&E should include capacity and energy payment provisions which comply with our decisions in OIR 2 and are reasonable.

3. The capacity and energy payment provision of the utilities' standard offers for as-available capacity and energy and firm capacity should be modified in keeping with the discussion and findings of this decision.

4. To promote the signing of standard offers by QFs, this order should be made effective today.

O R D E R

IT IS ORDERED that:

1. Within 45 days of the effective date of this order, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E) shall file with the Commission's Docket Office an original and twelve copies of appropriate amendments to the standard offers included in Applications (A.) 82-03-26, 82-03-37, and 82-03-78 consistent with this decision and the ordering paragraphs contained herein.

2. Each utility's standard offer for firm capacity shall include the following requirements governing the performance standards to be applied to a qualifying facility (QF):

a. Each standard offer shall include two payment options, one based on a QF's availability and the other based on a QF's energy production or output. PG&E's Standard Offer No. 2, Appendix C, Options 1 and 2, as modified in accordance with this order, shall serve as models for these payment options.

b. Dispatchability shall be defined to permit the utility to require only increases, not decreases, in a QF's operation. Dispatchability need not be limited to on- and mid-peak periods and emergencies if the utility's payment option based on availability is similar to PG&E's Option 1.

c. Each payment option for firm capacity shall provide for payments in excess of a utility's capacity costs for QFs whose performance exceeds that of the utility's plants. To receive the higher payment, the QF's performance shall consistently exceed a peak period availability or capacity factor of 85%. For offers based on 100% of a utility's capacity costs, a QF shall only be required to maintain an availability or capacity factor of 80%. For a payment option based on a QF's availability which permits the higher payment, each utility shall include in the standard offer a method of determining whether and to what extent the QF has been dispatchable at a level of 85% or better.

d. Each utility's standard offer for firm capacity shall provide that hydroelectric QFs, which have their capacity ratings based on the five dry year average, shall not have their capacity terminated or derated when their failure to meet minimum performance requirements is due solely to the occurrence of a dry year which is drier than the five dry year average. During drier year conditions, a hydro QF shall be paid for the amount of capacity, if any, actually delivered to the utility. Capacity payments shall resume, at the contract price, when hydro conditions once again reach the level used to determine the capacity rating.

e. Each utility's standard offer for firm capacity shall include an allowance for scheduled maintenance which provides as follows: (1) Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. (2) A QF may accumulate unused maintenance hours on a year-to-year basis up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. (3) Reasonable advance notice to the utility of a scheduled outage shall be 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six months for a major overhaul. (4) Major overhauls shall not be scheduled during the peak summer months. Reasonable efforts to schedule or reschedule routine maintenance outside the peak summer months shall also be made, but in no event shall outages for scheduled maintenance exceed 30 peak hours during the summer peak months. (5) No restrictions shall be imposed on the use of the scheduled maintenance allowance during the initial period of operation (i.e., the first six months). (6) Capacity payments shall apply during allowed outages for scheduled maintenance.

f. Each utility's payment options for firm capacity shall include provisions for the reduction of capacity payments in the event the QF fails to meet the minimum performance requirements. For both payment options, a probationary period not to exceed 15 months shall be adopted. For an availability option, like PG&E's Option 1, if a QF fails to meet the minimum performance requirements, it shall continue to receive capacity payments for the amount of dispatchable capacity available during the probationary period. If after the expiration of this period, the QF has not demonstrated an ability to provide its full contract capacity to the utility, that capacity shall be derated and subsequent monthly payments limited to the new contract capacity. The amount by which the QF's capacity is reduced shall be subject to termination provisions. For an output option, like PG&E's Option 2, the QF shall earn capacity payments during the probationary period for the amount of capacity actually delivered. If the QF fails to deliver the full contract capacity during each of the following year's peak months, the contract capacity shall be derated to the monthly amount of capacity actually delivered during the peak months. The amount by which the QF's capacity is reduced shall be subject to termination provisions. Under both otions, for capacity actually delivered during the probationary period, an allowance or credit for forced outages at the level otherwise specified in the utility's standard offer shall be included. The standard offer shall not include a provision for retroactive payments.

3. Edison's single payment option for firm capacity based on a QF's output and SDG&E's firm capacity payment Options 1 and 2 are not in compliance with D. 82-01-103 and shall not be included in any standard offer for firm capacity.

4. The utilities' standard offers for firm capacity shall not include provisions for a QF to receive as-available capacity payments during the start-up period prior to the commencement of its firm capacity operations.

5. Each utility's standard offer for firm capacity shall include termination provisions which meet the following requirements:

a. Each utility shall provide for the reduction of capacity payments under the circumstances and in the manner provided in Ordering Paragraph 2(f) of this decision. Reductions in contract capacity shall not result in a complete termination of the contract but the amount by which the capacity is reduced shall be subject to termination provisions.

b. Each utility's standard offer for firm capacity shall require a QF terminating with prescribed notice to reimburse the utility for unearned capacity payments. Each of the utilities' methods for calculating this repayment, which are otherwise reasonable, shall include the requirement that interest be charged on the amount refunded. The interest charged shall be the published Federal Reserve Board three months' Prime Commercial Paper rate (plus 50 basis points for SDG&E).

c. The specific notice required for termination with notice shall vary depending on the amount of capacity being terminated. Tables similar to those in PG&E's and SDG&E's standard offers for firm capacity shall be included in each of the utilities' standard offers.

d. Each utility's standard offer for firm capcity shall require a QF terminating without prescribed notice to refund overpayments and to cover the utilities' replacement costs for the lost or reduced capacity. The offers shall include a liquidated damage clause calculating this additional payment for replacement costs similar to that prescribed in PG&E's Standard Offer No. 2, Appendix D (which reflects the actual notice given), with one modification. The adopted formula shall reflect the time needed, as indicated by the notice table, to replace the lost capacity. The utilities' calculation of their damages may refer to future capacity prices.

e. The utilities' termination provisions shall not require a QF to provide evidence of its ability to make potential termination payments.

f. Each utility's standrd offer for firm capacity shall include examples of the operation of its termination provisions.

g. The requirements of D.82-01-103 with respect to conversions from the simultaneous purchase and sale of energy to the sale of surplus only shall be reflected in a utility's standard offer for firm capacity. Termination provisions shall only apply to the amount by which the contract capacity is reduced as a result of the conversion.

6. A standard offer for as-available capacity shall not include any notice requirement for termination.

7. The utilities shall file, along with the amendments to the standard offers ordered in Ordering Paragraph 1 above, firm and as-available capacity prices based on 100% of the capital costs of the combustion turbine, using the combustion turbine cost estimates adopted in this decision.

8. Edison's combustion turbine capital costs shall be based on the following assumptions:

a. A $415/KW 1982 combustion turbine cost.

b. A 23-year economic life.

c. Escalation and discount rates proposed by staff for Edison in this proceeding.

d. Fuel inventory costs proposed by staff with the exception that staff's inventory escalation rate shall be reduced by 50%.

e. Administrative and general costs which, on a levelized basis, shall be equivalent to 1% of the combustion turbine capital cost.

f. No differential fuel credit.

g. Fixed operation and maintenance costs to which staff and Edison have agreed in this proceeding.

9. SDG&E's combustion turbine capital cost shall be based on the following assumptions:

a. A $400/KW 1982 combustion turbine capital cost.

b. A 15.5% incremental cost of capital.

c. Fixed administrative and general costs commensurate with those adopted for Edison.

d. Fuel inventory costs, fixed operations and maintenance costs and plant economic life to which staff and SDG&E have agreed in this proceeding.

e. Staff's proposed escalation rates for SDG&E.

10. PG&E's combustion turbine capital cost shall be based on the following assumptions:

a. A $450/kW 1982 combustion turbine cost.

b. Escalation rates adopted for Edison and SDG&E.

c. A 15% incremental cost of capital.

d. Fuel inventory costs commensurate with those adopted for Edison.

e. Plant economic life, fixed operation and maintenance costs; and fixed administrative and general costs adopted for combustion turbine cost estimation in D.93887.

11. More refined shortage cost methodologies such as those proposed by the utilities in this proceeding for firm capacity payments shall be examined for possible application to QF pricing in SDG&E's and PG&E's current general rate cases and hearings on Edison's five-year energy price offer (A.82-04-46). Any revision in capacity prices that is adopted by the Commission because of this examination shall only apply prospectively to QFs that sign after the date of the orders in those proceedings.

12. Each utility's standard offer for energy shall reflect the following:

a. Each utility shall modify its as-available and firm capacity contracts, and its contract for QFs less than 100 kW to state that energy prices will be derived from the utilities' full avoided operating costs, as approved by the Commission, throughout the life of the contract.

b. Utilities shall file with the Commission's Docket Office beginning six months from the effective date of this order an original and twelve copies of their actual average incremental heat rates and fuel use quarterly, in the case of PG&E and Edison, and three times a year, in the case of SDG&E. The relevant models shall be modified to make whatever changes are required.

c. Utilities shall use the average year incremental heat rates, as determined in the most recent rate case, for the derivation of energy prices until the Commission approves refinements.

d. The utilities shall file with the Commission's Docket Office by September 30, 1983 an original and twelve copies of a plan for estimating actual year incremental heat rates prospectively.

e. Utilities shall propose incremental heat rate revision in Energy Cost Adjustment Clause (ECAC) proceedings after new power plants come on line.

f. PG&E and Edison shall file with the Commission's Docket Office an original and twelve copies of prospective energy prices quarterly, 30 days prior to the date the prices take effect. Included with the filing shall be a clear, comprehensive description of how the prices were derived, in order to permit staff and interested parties to comment on them. Gas prices used for avoided energy costs shall be tentative and finalized using the price in effect on the effective date of the price change.

g. Absent Commission action, these price offers shall take effect on the scheduled effective date.

h. SDG&E shall file its energy prices three times a year in parallel with ECAC proceedings. Unless the Commission orders revisions, these prices shall become effective on the scheduled effective date. SDG&E shall provide a clear, comprehensive description of how the prices were derived.

i. SDG&E shall use the GN-5 natural gas rate for the determination of its energy prices.

j. Until revised line loss adjustment factors are approved by the Commission, PG&E's, Edison's, and SDG&E's transmission and primary distribution loss adjustments for energy shall be set at 1.0. Marginal line losses shall be used for PG&E's, SDG&E's, and Edison's secondary distribution loss adjustment for energy.

k. PG&E shall complete a revised line loss study in cooperation with staff and QF representatives and file an original and twelve copies with the Commission's Docket Office within six months of the effective date of this order. The study shall include a methodology for identifying and determining losses from remote sites.

l. SDG&E and Edison shall complete line loss simulation studies in cooperation with staff and QF representatives within two years and file an original and twelve copies of the results with the Commission's Docket Office.

m. Utilities shall include variable operating and maintenance costs in energy prices.

n. Utilities shall permit meters to be fixed on the utility side of a transformer. Transformer loss provisions shall be removed from standard contracts if a QF decides to put the meters on the utility side.

o. Offers to include 600 hours of curtailment in exchange for a higher energy rate the rest of the time, to levelize energy payments, or to adopt floors shall be viewed as nonstandard offers at this time, and outside the scope of these proceedings. Any such provisions shall not be included in standard offers.

p. Utilities shall delete any language which would reduce capacity payments for QFs during periods when they fail to perform under capacity contracts due to the utility refusing to purchase from the QF.

q. PG&E, Edison, and SDG&E shall file with the Commission's Docket Office within three months of the effective date of this order an original and twelve copies of studies estimating the average and maximum probable application of refusal to purchase and hydro spill provisions in future years.

13. The petitions for modification filed by CMA and Imotek, Inc. in OIR 2 are dismissed.

This order is effective today.

Dated December 30, 1982, at San Francisco, California.

RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
Commissioners

I will file a concurring opinion.

/s/ LEONARD M. GRIMES, JR.
Commissioner

Commissioner Priscilla C. Grew, being necessarily absent, did not participate.

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

Joseph E. Bodovitz, Executive Director

APPENDIX A
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LIST OF APPEARANCES

Applicants: Daniel E. Gibson, David L. Ludvigson, Jo Shaffer, and Ken D. Oleson, Attorneys at Law, for Pacific Gas and Electric Company; Margaret A. Glodowski, Attorney at Law, for Sierra Pacific Power Company; Thomas F. Mulvaney, Attorney at Law, for CP National Corporation; Stoel, Rives, Boley, Fraser and Wyse, by Thomas H. Nelson, Attorney at Law, for Pacific Power & Light Company; Margaret Sullivan and Wayne P. Sakarias, Attorneys at Law, for San Diego Gas & Electric Company; and Eugene Wagner, Richard K. Durant, Clyde E. Hirschfeld, Carol B. Henningson, and Frank J. Cooley, Attorneys at Law, for Southern California Edison Company.

Interested Parties: Chickering & Gregory, by C. Hayden Ames, Attorney at Law, and C. M. Laffoon, for Geothermal Generation, Inc.; Robert Burt, for California Manufacturers Association; James J. Cherry, Attorney at Law, for Independent Power Producers Association; Janet M. Curry, for Department of Water Resources; Robert Danziger, Attorney at Law, for Sunlan Energy Corporation; Michel Peter Florio and Robert Spertus, Attorneys at Law, and Sylvia Siegel, for Toward Utility Rate Normalization (TURN); James Helmich, for Helmich Engineering; Mark Henwood, for Henwood Associates, Inc.; Steven F. Hirsch, Attorney at Law, and Laura B. King, for Natural Resources Defense Council, Inc; Catherine Johnson, Gregg Wheatland, Kathy Weinheimer, and Daniel Meek, Attorneys at Law, for California Energy Commission; Morrison & Foerster, by Charles R. Farrar, Jr. and Alan Cope Johnson, Attorneys at Law, for Great Western Malting Company, Kerr-McGee Chemical Company, and Kimberly-Clark Corporation; Jane S. Kumin, Attorney at Law, for Natomas Company and Thermal Power Company; John C. Lakeland, for Mass-Production Systems; W. J. Lawrence, for Western Energy Associates; Philip R. Mann, Attorney at Law, for CMA Cogeneration Group and P. R. Mann & Associates; Graham & James, by Boris H. Lakusta, David J. Marchant, Thomas J. MacBride, and James B. Henly, Attorneys at Law, for Graham & James; Wayne L. Meek, for Simpson Paper Company; Michael McQueen, Attorney at Law, for Union Oil Company of California; Hanna & Morton, by R. Lee Roberts, Attorney at Law, for Hanna & Morton; Donald G. Salow, for Stone & Webster

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Management Consultants, Inc.; Robert W. Schempp, for Metropolitan Water District of Southern California; Petty, Andrews, Tufts & Jackson, by Allen J. Thompson, Attorney at Law, for California Independent Energy Producers; Randall Tinkerman, for Transition Energy Projects Institute; Harry Winters and David A. Dorinson, Attorney at Law, for University of California; Robert M. Loch, Attorney at Law, for Southern California Gas Company; Donna M. Bronski and Don Dier, for Department of General Services; Gordon E. Davis, William H. Booth and Richard C. Harper, Attorneys at Law, for Brobeck, Phleger & Harrison; Grattan, Gersick & Karp, by John P. Grattan, Attorney at Law, and John V. Hilberg, for Calcogen, Inc.; Ken Haas, Attorney at Law, for Windfarms, Ltd.; Janice G. Hamrin, for Independent Energy Producers Association; Neil K. Holbrook, for California Wind Energy Association; Jeffrey B. Jackson, and Thomas D. Clarke, Attorneys at Law, for Central Plants, Inc. and Pacific Hydropower Company; Peter S. Reis, Attorney at Law, for Texaco, Inc.; Leonard L. Snaider, Attorney at Law, and Robert Laughead, P.E., for the City and County of San Francisco; Mark Farman, for Resource Management International; Carl E. Salas, for O'Brien Associates, Inc; Jasper Williams, Attorney at Law, and William Swanson, for Stanford University; Jerry R. Bloom, Attorney at Law, for Kimberly-Clark Corporation; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for Federal Paper Board; Sutherland, Asbill and Brennan; Edward J. Grenier, Jr., Esq.; and Earle H. O'Donnell, Esq.; Hanna & Morton, by R. Lee Roberts, Attorney at Law, and William C. Prentice, for Ultrasystems, Inc.; Ernest Lampert, for United Energy Corporation; Brobeck, Phleger & Harrison, by Gordon E. David, William H. Booth, and Richard C. Harper, Attorneys at Law, for Imotek, Inc.; Terry Trumbull and Robert F. Conheim, Attorneys at Law, for the California Waste Management Board; Peter S. Merrill, for Cogenerating Power Company; William S. Shaffran, Deputy City Attorney, for John W. Witt, City Attorney, for the City of San Diego; John Donald Eppick, for County Sanitation Districts of Los Angeles County; Gordon E. Davis and William H. Booth, Attorneys at Law, for U.S. Windpower, Inc.; and Matthew V. Brady, Attorney at Law, Doug Knight, and Vincent Schwent, for themselves.

Commission Staff: Brian T. Cragg and Lynn T. Carew, Attorneys at Law, and John Quinley.

(END OF APPENDIX A)

COMMISSIONER LEONARD M. GRIMES, JR., Concurring:

I concur in today's decision and write separately to express my views on projects which are designed to convert solid waste into electrical energy. I believe that these projects are of special value since they address the problem of public waste disposal in addition to providing all the benefits associated with alternative energy development.

Despite some efforts at recycling, we are still a throw-away society. Thousands of tons of waste are generated in our cities each day to the point where garbage may be the principal product of our urban centers. As the public officials responsible for "managing" our garbage are well aware, the economic and environmental costs of municipal waste are substantial.

Spurred on by landfills which are full and near-full and the difficulty of securing additional disposal capacity, a number of California cities have planned waste-to-energy systems ranging from 5 to 38 MW. These projects are among the most capital-intensive endeavors undertaken by local governments. Their success, in part, will depend on the terms and conditions under which the cities will be paid for the power they produce.

While today's decision on the short term standard offers does not address waste-to-energy projects specifically, the decision should be of some assistance to these projects. The firm capacity output option may be attractive to waste-to-energy producers. The long term offer which is being developed may also be a useful option. Should non-standard contracts be necessary, I urge PG&E, SDG&E, and Edison to make every effort to sign reasonable contracts.

In my opinion, the risk to electric ratepayers from waste-to-energy projects is mitigated by the fact that such projects will be developed and operated by public agencies which are clearly interested in the long term operation of their facilities. Also, attempts to shield electric ratepayers may ultimately prove to be futile. Risks not absorbed by electric ratepayers are simply shifted to garbage ratepayers. In many cases, they will be the same people responsible for generating the garbage in the first place.

LEONARD M. GRIMES, JR., COMMISSIONER

San Francisco, California
January 5, 1982

ALJ/km

Decision 82 12 120. DEC 30 1982

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision 82-02-103 in Order Instituting Rulemaking No. 2.	Application 82-03-26 (Filed March 8, 1982)
SOUTHERN CALIFORNIA EDISON COMPANY, application for 3 standard offers for purchase of electric power from cogeneration and small power production facilities.	Application 82-03-37 (Filed March 8, 1982)
Application of SIERRA PACIFIC POWER COMPANY, for approval of its standard offer to purchase cogeneration and small power production facilities.	Application 82-03-62 (Filed March 16, 1982)
Application of PACIFIC POWER & LIGHT COMPANY for Approval of Certain Standard Offers Pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-03-67 (Filed March 18, 1982)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for an Order by the California Public Utilities Commission Directing SDG&E to Purchase Power From Qualifying Facilities Based on Standard Offers and to Make Certain Changes or Additions to its Tariffs Affecting Purchases from Qualifying Facilities.	Application 82-03-78 (Filed March 22, 1982)

Application of CP NATIONAL CORPORATION for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.) Application 82-04-21 (Filed April 8, 1982)

Rulemaking on the Commission's own motion to establish standards governing the prices, terms, and conditions of electric utility purchases of electric power from cogeneration and small power production facilities.) OIR 2 (Petition for Modification Filed September 10, 1982)

(See Appendix A for appearances)

O P I N I O N

Introduction

This decision represents a further step by this Commission toward its stated goal of promoting the development of cogeneration and small power production facilities, alternatives to the traditional generation of electric power through the use of fossil fuels. Our policy, developed in previous decisions, will be served by this order's clarification and further definition of the proper relationship between public utilities and these alternate generation resources.

To date, the most significant proceeding in this regard has been Order Instituting Rulemaking (OIR) 2. OIR 2 was commenced to establish standards governing the prices, terms, and conditions of utility purchases of power produced by qualifying cogeneration and small power production facilities (qualifying facilities or QFs). The proceeding was stimulated by our own independent action and analysis, as well as the requirements of both state law (Public Utilities (PU) Code § 2821) and federal law (the Public Utility Regulatory Policies Act of 1978 (PURPA)). PU Code § 2821 requires the Commission to "approve and establish equitable charges" to be paid to privately owned generation facilities. PURPA and the resulting regulations adopted by the Federal Energy Regulatory Commission (FERC) specify rules governing a public utility's purchase of power from cogenerators and small power producers who qualify for the benefits of the law. The FERC regulations require state implementation.

On January 21, 1982, we issued Decision (D.) 82-01-103 in OIR 2. The decision ordered the major California electric utilities to file standard offers for power purchases from qualifying facilities based on avoided cost principles. We concluded that avoided cost pricing would promote the maximum efficient development of these alternative resources.

The standard offer ordered by D.82-01-103 was intended to describe not only the prices to be paid to QFs, but the rights and obligations corresponding to those prices. The standard offer is, in other words, an economic package in which the prices and the contract terms are inextricably bound together.

In order to meet the varied needs of QFs, the standard offer, designed to recognize the two basic components of a power purchase - energy and capacity, provided five different options. The options, expressed as separate offers, were further distinguished by the time within which they were required to be filed by the utilities. A shorter time frame was assigned to those offers which we felt could be reviewed more expeditiously. The offers and filing periods were as follows:

1. Within 45 days of the effective date of D.82-01-103, the utilities were ordered to file standard offers for:

   a. As-available energy and capacity based on a short-run avoided cost methodology.

   b. Firm capacity based on a short-run marginal cost methodology.

   c. Energy and capacity provided by QFs below 100 kilowatts (kW) in size.

2. Within 90 days of the effective date of D.82-01-103, the utilities were ordered to file standard offers for:

   a. Energy based on a forecast of energy payments for up to five years tied to either an as-available or firm capacity option.

   b. Firm capacity based on a utility's long-run marginal costs developed from the utility's resource plan.

The scope of the present proceeding is limited to those offers for which a 45-day filing was set in D.82-01-103, as listed under item 1. above. Five-year forecasted energy payments and long-term firm capacity offers will be reviewed in subsequent proceedings (Application (A.) 82-04-44, A.82-04-46, and A.82-04-47).

In D.82-01-103, the Commission outlined the procedure which would be followed in the approval of the offers filed after 45 days. Following staff review, the offers were to take effect two weeks after the date of filing unless otherwise suspended by the Commission. Each of these offers would then be reviewed in subsequent evidentiary hearings to determine the utility's compliance with D.82-01-103 and the factual basis for the prices contained in the offers. By D.82-04-071 (April 12, 1982), a subsequent order modifying D.82-01-103 and denying rehearing, all utilities were required to amend their initial filings to conform to the prescribed modifications and cure specific deficiencies identified in D.82-04-071. The presently effective offers were filed in May and July 1982.

<u>Procedural Background</u>

A. <u>Prehearing Matters</u>

Compliance hearings as required by the Commission in D.82-01-103 commenced with a prehearing conference held on May 10, 1982, in San Francisco, California. At that time, the presiding administrative law judge (ALJ) announced that at page 144 of D.82-01-103 the Commission had prescribed the scope of the hearings as follows:

> "These evidentiary hearings...will be narrowly restricted to the issues of each utility's compliance with the requirements of this decision and of the factual basis for the prices contained in each standard offer. The evidentiary proceeding will <u>not</u> be a forum for reexamining the issues resolved in this decision." (Emphasis original.)

During the prehearing conference, however, it became clear that, even with this limitation on the hearings, there remained numerous issues related to both the utilities' compliance with D.82-01-103 and subjects not resolved by that decision, but relevant to the standard offers. More than 25 parties voiced their concerns and offered suggestions with how to proceed in this complex matter.

Based on statements made at the prehearing conference and subsequent written statements filed by applicants and the Commission staff (staff) on May 14, 1982, an ALJ ruling was issued on May 19, 1982. The ruling included the following determinations:

1. To initiate hearings, the completion of staff reports related to the applications of Southern California Edison Company (Edison) (A.82-03-37), Pacific Gas and Electric Company (PG&E) (A.82-03-26), and San Diego Gas & Electric Company (SDG&E) (A.82-03-78) were necessary. Several of the applicant utilities had argued that their applications were intended to comply with the orders issued in OIR 2. Therefore the response of staff or interested parties to those filings were required in order to identify the issues.

2. Following receipt of staff's report on Edison, public hearings would commence on July 12, 1982, with Edison's direct showing.

3. Hearings on the applications of Sierra Pacific Power Company (A.82-03-62), Pacific Power & Light Company (A.82-03-67), and CP National Corporation (CP National) (A.82-04-21) would be deferred until staff reports could be issued on those applications.

4. The ALJ concurred with the staff that issues to be considered in this proceeding extended to questions dealing with provisions included in the utilities'

applications, although not specifically addressed by the Commission in its OIR 2 decisions, as well as an applicant's compliance with those orders.

5. The tariffs required by D.82-01-103, Ordering Paragraphs 18 and 19 (standby rates) and Ordering Paragraph 21 (parallel generation), should be considered an integral part of the subject standard offers for purposes of assessing their compliance with OIR 2 and must therefore be made part of each of the subject applications.

B. Hearings

1. Expert Testimony

Following this ruling, 40 days of hearing were held between July 12, 1982 and October 15, 1982, in San Francisco. During that time, testimony was presented relating to the applications of PG&E, Edison, and SDG&E. Between the applicant utilities, the Alternate Generation and Rate Design Sections of the staff, state and local government agencies, and businesses and individuals presently or potentially operating or involved with cogeneration and small power production facilities. a total of 41 witnesses were called to testify. Many of these witnesses, who included experts in engineering, economics, law, and management, testified more than once during the hearings. Interested parties, representing various types of QF development, accounted for 17 of these witnesses. Seventy-four exhibits were received into evidence.

2. Statements

During the course of the proceeding, a number of individuals had expressed their desire to offer statements, as opposed to testimony, during hearing. In response to these requests, the ALJ, in noticing the hearing dates to be reserved for the testimony of interested parties, also set a specific date for public statements.

On August 30, 1982, 18 people offered their views relating to the standard offers at issue. These individuals were uniformly concerned that various provisions of the utilities' standard offers were not in keeping with this Commission's and PURPA's policy of encouraging the development of qualifying facilities. In particular, these individuals questioned the utilities' bases for the calculation of their avoided costs and the reasonableness of certain provisions of the standard offers which they considered to be penalties or obstacles to QF development.

Most of those making statements either were purchasers or sellers of small, home-sized (1 to 10 KW) wind generators. Their chief concern was the level of insurance required of QFs under the standard offers. It was argued that the premium level exceeded both the revenue benefit to be derived from installation of a wind generator as well as any risk created by such a facility. All agreed that the present insurance requirements would stifle the growing potential of this alternate resource.

In addition to these statements, other individuals either took the opportunity during other regularly scheduled hearing days to make statements or wrote letters to the Commission on the subject. These statements and correspondence, which were most frequently industry-specific, raised concerns similar to those expressed in other testimony and comments and asked the Commission to adopt standard offers which would encourage, not discourage, QF production.

C. Consideration of Firm Capacity Methodology

During the hearings PG&E and Edison attempted to offer testimony and question the staff on the proper methodology for determining the as-available capacity and firm capacity prices to be paid to QFs. By oral ALJ ruling on July 20, 1982, all parties were precluded from addressing this issue on the grounds that the issue had been resolved in OIR 2 and was beyond the scope of these compliance proceedings. This ruling was based on a review of the language of D.82-01-103 and D.82-04-071 in OIR 2 and consultation with the assigned Commissioner's office. On July 26, 1982 PG&E filed a motion with the Commission seeking reversal of this ruling. Edison filed a similar motion on July 29, 1982.

The assigned Commissioner concluded that this matter did not need to be referred to the Commission, but rather should be resolved by further ALJ ruling. Upon consideration of the petitions of PG&E and Edison and further review of the applicable Commission decisions, it was determined that the ALJ's ruling should be reversed in part and affirmed in part. Specifically, it was concluded that this proceeding was the proper forum for addressing the issue of the appropriate methodology for determining capacity costs, based on the shortage cost concept, under a utility's firm capacity standard offer. Revision of the methodology for calculating a utility's as-available capacity payment adopted in D.82-04-071, however, was reserved for the utilities' general rate cases as specified in that decision.

Testimony by all parties on the issue of the proper methodology for calculating a utility's firm capacity price was heard over a 10-day period following the presentation of all other testimony. In order to expedite the submission of this matter, certain information proposed by PG&E relating to this issue was directed to be served on the parties after the final day of hearing.

D. <u>Submission</u>

At the conclusion of the final day of hearing on October 15, 1981, and in an ALJ ruling issued that same date, A.82-03-26, A.82-03-37, and A.82-03-78 were submitted upon the following:

1. The submission by PG&E of an additional proposal and adjustment related to the Energy Reliability Index used by PG&E in calculating its shortage costs on which PG&E's standard offer for firm capacity will be based.

2. The filing of concurrent briefs on November 15, 1982.

PG&E was directed to serve its proposal on all appearances in this proceeding. Any party wishing to address or request a hearing on this proposal was directed to do so in the briefs due on November 15. Requests for hearing were to include a specific identification of the basis for the request and any questions to be addressed in cross-examination.

On the final day of hearing, SDG&E was also directed to furnish a copy of its input assumption data ~~upon~~ to staff, which had formally requested it on October 15, and ~~upon~~ to the State Energy Task Force, prior to the end of the briefing schedule. According to the briefs, this material had not been received by that time.

On October 25, 1982, PG&E filed its proposal. PG&E also submitted on November 2, 1982, a recalculation of its annual Energy Reliability Index adjustment factors based on a "low" load management scenario.

Between November 15 and 17, 1982, concurrent briefs were filed by a total of 16 parties including PG&E, Edison, SDG&E, staff, the Independent Energy Producers (IEP), the California Manufacturers Association (CMA), Occidental Geothermal, Inc. (Occidental), Ultrasystems, Inc., Federal Paper Board Company, Inc., the Regents of the University of California (UC), Calcogen, Inc., the California

Energy Commission (CEC), the State Energy Task Force, the California Waste Management Board, Kimberly-Clark Corporation, and Simpson Paper Company. Any delays in filing were attributable to breakdowns in required support systems. Correspondence was also received at that time addressing issues similar to those presented in the briefs.

<u>Positions of the Parties</u>

The testimony received during hearing in this proceeding was sponsored by numerous witnesses representing a variety of interests, including those of the applicant utilities, government, and private industry. The views of 16 of the appearances regarding this record have been expressed in concurrent briefs. Other parties, although providing testimony, have chosen not to file briefs, in some cases apparently due to a lack of economic resources. Still others have addressed the issues raised during hearing in correspondence to the Commission. To provide an overall description of the parties' basic viewpoints, we have summarized the positions below.

A. <u>Utilities</u>

All three utilities, PG&E, Edison, and SDG&E, believe that their applications are in full compliance with this Commission's decisions in OIR 2. Each asserts that the record fully supports this conclusion.

The utilities are also of the opinion, however, that to promote the continued development of QF power, certain amendments to their standard offers may be desirable. Each utility asks that it be recognized that any suggested modifications of its standard offers do not result from a failure to comply with OIR 2, but rather are aimed at better achieving the goal of QF development.

According to their briefs, the determination or adoption of any standard offer amendment by a utility was greatly influenced by the utility's perceived responsibility to its ratepayers. The utilities believe that the PURPA mandate requiring prices paid for QF power to be just and reasonable to ratepayers is embraced in the concept of avoided cost. Under that concept, the utility is to pay the QF a price equal to the cost the utility would have incurred had it generated the electricity itself or purchased the power elsewhere. The ratepayer should therefore remain indifferent to whether the utility or the QF produces the power.

This principle of ratepayer indifference has led the utilities to conclude that a standard offer must result in a proper allocation between QFs and utilities of the risks associated with the transaction. Should business and economic risks be shifted to the utility and its ratepayers disproportionate with the benefits to be received from QF production, a ratepayer would no longer remain indifferent since that risk would ultimately be translated into additional costs to the ratepayer.

The utilities' briefs also reflect the view that the standard offer is a single, integrated economic package. SDG&E specifically advises that the division of issues in its brief is arbitrary since all of the standard offer provisions relate to price in one way or another.

B. Staff

The staff states that its primary concern is whether or not the utilities' standard offers comply with this Commission's decisions in OIR 2. Staff is of the opinion, however, that to develop effective standard offers the issue of compliance should include an examination of (1) the propriety of contract terms which the Commission has yet to direct be included or excluded from the standard offers. (2) the determination of a utility's true avoided costs. and (3) the need for standardization of contract terms between different utilities' standard offers.

Like the utilities, the staff's recommendations are intended to achieve the proper balance of ratepayer and QF interests. The risks associated with the standard offers, however, are viewed somewhat differently by the staff than by the utilities. In particular, the staff notes that the QF market is still in its infancy. This circumstance has two results - the need for continued encouragement for its development and an increase in the risks which potential investors and owners perceive are associated with a QF's operations. It is the staff's belief that ratepayers who will benefit from the increased development of alternate energy resources should share in the risks related to this emerging industry.

C. Private Industry

This category includes a total of eight parties representing the interests of currently operating or potential QFs. Among these parties were two associations: IEP, representing a group of California cogenerators, small power producers, and related businesses, and CMA, representing industries some of whom desire to participate in QF programs and other who do not. Briefs were also filed by Occidental, Ultrasystems, Inc., Federal Paper Board Company, Inc., Calcogen, and Kimberly-Clark Corporation and Simpson Paper Company, who sponsored a joint brief.

The participation of all of these parties has focused on challenges to either the utilities' compliance with OIR 2 or their proposed methodologies for calculating their firm capacity payments, an issue included within the scope of this proceeding. Influencing the positions taken by these parties has been their particular perception of the risks associated with the utility-QF transaction and the proper allocation of those risks. It is the opinion of the industry that to require the QF to bear certain of these risks will ultimately stifle the development which the Commission specifically sought to encourage in OIR 2.

According to these parties, among the risks facing QFs is the inability to obtain financing for projects and predict, on the basis of the contract terms, what each QF can expect in the future. These concerns have been heightened by a substantial drop in avoided cost payments to QFs. This circumstance has jeopardized the operations of current producers and the projects of potential QFs.

Because of this asserted instability in the industry, QFs in their testimony and briefs have been most concerned with the utilities' methods for calculating avoided costs, the availability of data to verify those calculations, the standards of performance required of QFs, the ambiguity and lack of standardization with respect to certain contract terms, and the utilities' assignment of particular risks to QFs, including the risk of future regulatory changes.

It is the view of the industry that QF production reduces the risks to which ratepayers would otherwise be exposed by utility operations. For this reason, it is the industry's position that QF development should not be stifled by the improper calculation of price, the absence of proper incentives, or a demand for performance which exceeds that of a utility's own plants.

D. State Government

Besides this Commission's staff, briefs were filed by four other state governmental entities: the CEC, the California Waste Management Board, the State Energy Task Force, and UC. With the exception of the CEC, each of these entities ~~are~~ is involved directly in the development of alternate generation ~~resources~~ facilities. ~~for the ultimate benefit of the State.~~

The positions expressed by these parties have been formulated based on a strong desire for the continued encouragement of QF development and for the resolution of problems created by unique arrangements and resources in which the State, in certain cases, intends to be involved. With respect to this latter circumstance, this Commission has been asked to consider the special needs and benefits of projects converting solid waste into energy and the impact on the standard offer of the State itself being a party to or potential beneficiary of the agreement.

Aside from these special concerns, the views of these state entities mirror those held by the QF industry. The utilities' avoided cost calculations are questioned, while standardization of and certainty in contract terms are urged. It is the opinion of state government that its recommendations take into consideration the appropriate allocation of risks between QFs and ratepayers.

E. Positions Expressed in
Testimony or Correspondence

The participation of four of the interested parties to this proceeding was limited to the receipt of their testimony; no briefs were filed. These parties included the California Wind Energy Association (CalWEA), ~~who~~ which indicated that its financial resources for participation were limited; American McGaw, a manufacturer owning a 2,800 kilowatt (kW) cogeneration facility in California; Henwood Associates, consultants negotiating contracts and arranging financing for QFs; and the County Sanitation Districts of Los Angeles County, the City of Commerce, and the City of Long Beach, local government entities with an interest in waste-to-energy projects.

The sole purpose of the two exhibits sponsored by CalWEA was to challenge the insurance requirements of the utilities' standard offers. Because of the high cost of such insurance and the documented safety of farm- and home-sized wind generators, CalWEA has urged the modification or elimination of the utilities' insurance provisions for wind systems of 20 kW or less. The testimony of the County Sanitation Districts expressed concerns regarding waste-to-energy projects similar to those contained in the testimony and brief of the California Waste Management Board. American-McGaw's testimony covered issues and expressed opinions comparable to those of other industry representatives. Henwood Associates focused on perceived shortcomings in Edison's standard offers.

At the time of submission of this matter, Helmich Engineering, United Energy Corporation, and Hudson Lumber Company wrote to this Commission indicating their views. Mr. James E. Helmich of Helmich Engineering is an appearance of record, while the latter two corporations are members of IEP. Price fluctuation, which in one case has directly affected operations, was the primary concern of these companies. Like other individuals who have written to the Commission during the course of these proceedings, a resolution of this matter before the end of 1982 was urged to ensure the continued development of the QF industry.

Scope of the Decision

Before commencing our discussion on the issues raised in this proceeding, we must first consider two requests made by several parties regarding the scope and timing of this decision. It is the view of the QF industry that for its development to continue (1) an order resolving all of the issues relating to the subject standard offers must be reached and (2) that order must be issued expeditiously, preferably before the end of 1982. The standard offer is seen as a single, unseverable economic package, the provisions of which must be known before a QF can commence or continue its operations.

Unfortunately, with the extensive participation and record in this matter, the earliest submission date for these applications was November 15, 1982. As a result, we have been left little time to prepare an order which would resolve all of the standard offer issues this year, while simultaneously giving the proper weight and consideration to all of the views presented.

For this reason, although we recognize that the standard offer provisions are interrelated, we can address in this decision only certain of the issues arising from those offers. We believe, however, that the subjects chosen, i.e., the basic price issues and certain contract provisions, will provide sufficient options for QFs to make the economic decisions necessary for determining the merits of proceeding with or continuing a particular project.

By adopting this approach, we will be able to consider fully the record which the parties have spent appreciable time and effort developing. All appearances should be assured, however, that those issues which are not discussed in the order will be addressed as early as possible next year.

Specifically, this decision will examine the utilities' bases for and standard offer provisions relating to capacity payments and energy payments. Our discussion of capacity and energy payments will include consideration of such issues as performance requirements, termination, and periods of curtailment. We will also consider the propriety of providing for the conversion of standard offer contracts signed after the effective date of this order to the standard offers ~~standard offers based upon the utilities' short-run or long-run marginal costs which are ultimately~~ approved. in our forthcoming second opinion in this proceeding.

Capacity Payments

Because this proceeding was primarily intended to determine the utilities' compliance with our decisions in OIR 2, a basic understanding of those orders, as related to each of the issues to be considered, is critical. With respect to payments for capacity, this Commission concluded in D.82-01-103 that energy delivered on either an as-available or firm basis resulted in a utility avoiding capacity costs. Avoided capacity costs are those costs associated with ensuring the reliability of the production and delivery of electricity which the utility avoids incurring by purchasing power from a qualifying facility.

In OIR 2, the utilities had questioned whether any capacity costs are avoided when energy is delivered to the utility only as it becomes available. D.82-01-103 recognized, however, that as-available power, when aggregated, did in fact result in a reduction in demand upon the utility and thereby avoided certain capacity costs, including those associated with generation and generation-related transmission. Payments for as-available power, however, would not reflect any value for contract length, notice, termination, or sanctions since such provisions would not be part of an as-available offer.

In contrast, firm capacity was viewed as an increase in the utility's supply of electricity with corresponding performance standards, termination provisions, and sanctions. By definition, firm power is provided in predetermined quantities at predetermined times with sufficient legally enforceable guarantees of deliverability to permit the purchasing utility to avoid the construction of a generating unit or the purchase of ~~less~~ firm power elsewhere. A QF providing firm capacity, ~~which this Commission found to have no aggregate value equivalent to as-available capacity,~~ was determined to avoid costs additional to those related to as-available power. This result was to be reflected in the firm capacity payment.

With respect to the amount to be paid QFs for their output, D.82-01-103 requires "full avoided cost pricing of power from qualifying facilities." (Mimeo, at page 26.) For purchases of both firm and as-available capacity, PG&E, Edison, and SDG&E were directed to base their payments on each utility's estimate of its current shortage costs using a combustion turbine facility as a proxy.

Although recognizing that the combustion turbine was a somewhat less attractive methodology for firm, as opposed to as-available capacity, payments, we concluded in D.82-04-071 that revisions to the adopted methodology would only be considered in the future. For as-available capacity prices, consideration of such revisions was set for the utilities' general rate cases. No specific time, however, was identified for examining modifications of the methodology for calculating firm capacity payments. As stated previously, by ALJ ruling, the proper forum was found to be this proceeding.

Because the firm capacity payment should reflect certain factors not included in the as-available capacity price, the following discussion will commence with an examination of the utilities' standard offer terms governing performance and termination in a firm capacity contract. We will then review the methods by which the utilities have calculated the prices to be paid for both firm and as-available capacity.

A. Performance and Termination <u>Provisions in Firm Capacity Contracts</u>

Consistent with the applicable FERC regulations, D.82-01-103 states:

> "The firm capacity payment properly reflects the factors recited in Part IV,A, above related to the availability during system peak periods, including:
>
> "a. Dispatchability,
>
> "b. Reliability,
>
> "c. Contract duration, termination, and sanctions,
>
> "d. Scheduling of outages, and
>
> "e. Availability during emergencies.

"The value of each of these factors shall be calculated, based on standards comparable to performance standards the utility would impose on its own plants. These standards must, however, be fair to QFs and not impose unnecessary burdens that will discourage the development of these preferred resources. The sum of each of these factors and the resultant capacity value will be offered on both a dollars per kW per year and a cents per kWh basis as currently done. A QF that exceeds operating standards normally expected of utility plants should be able to earn a higher capacity payment." (Mimeo, at page 57.)

To aid in the development of standard offers incorporating these basic principles, D.82-01-103 provided further definition of the factors to be reflected in the firm capacity payments. This amplification of each factor can be summarized as follows:

1. Dispatchability. According to D.82-01-103, dispatchability is achieved in [illegible] offers by time basing capacity and energy prices and requiring QFs to maintain availability during peak load periods with a reasonable allowance for forced outages. QFs are to be expected to operate at maximum capacity on notice to meet utility needs for capacity during peak load periods and emergencies consistent with resource limitations.

2. Reliability. Reasonable requirements for reliable operation and availability during utility system peak load periods are to be imposed in the standard offers. These requirements, however, should not be unduly restrictive or complicated or impose standards of reliability greater than the utility plants the QF displaces. When resource limitations exist to reliable operations, such as with wind parks, plant capacity factor may be a better measure of reliable operation.

3. Contract duration, termination, and sanctions. QFs should be provided the option for levelized capacity payments for

periods up to 25 to 30 years. Other than general statements requiring fair contract requirements, the exact terms for provisions relating to termination and sanctions were not specified.

4. Scheduling of outages. A utility purchasing firm capacity from a QF may reasonably require the QF to schedule maintenance of that generation during periods established by the utility. The utility must provide reasonable periods for QF scheduled maintenance and only request deferments in the customer's requested maintenance schedule on 60 days' notice. Capacity payments must not be reduced during scheduled maintenance periods.

5. Availability during emergencies. A QF must be expected to operate at maximum capacity on notice to meet utility needs for capacity during emergencies.

Other than our recognition that plant capacity factor, as opposed to availability, might be a better measure of the reliable operation of certain technologies, D.82-01-103 did not endorse any special treatment for specific resources other than small hydroelectric facilities. For hydro QFs larger than 100 kW, adjustments for dry year unavailability were to be made in determining the QF's base stream flow and monthly firm capacity rating. A hydro QF would be allowed to use either (1) flow data directly applicable to the QF's facility, when available, or (2) the flow data for the area closest and most similar to the QF's facility, using areas sufficiently limited in size so that the true value of local areas would not be lost or obscured. The minimum June through August flow, from which the monthly firm capacity rating was to be derived, would be based on the five lowest flow years taken from a 50-year minimum continuous record. If this data could not be developed, utilities and QFs would agree upon a shorter time period with fewer minimum flow years averaged into a monthly capacity rating. For both options, capacity values were to be paid in dollars per kW per month and otherwise subject to the requirements of a firm capacity sale.

In examining the utilities' compliance with the OIR 2 decisions, we will first consider the issues relating to all of the above factors, except for termination. A review of the utilities' proposed termination provisions will follow in a separate section.

1. Performance Requirements

A finding of compliance or noncompliance with the requirements of D.82-01-103 enumerated above requires an understanding of each of the utility's standard offer provisions relating to performance. Additionally, the positions of both utilities and interested parties must be considered.

a. PG&E Standard Offer No 2, Appendix C - Firm Capacity Price Schedule

PG&E's standard offer provisions governing the conditions of firm capacity payments are set forth in Appendix C of its Standard Offer No. 2 (Firm Capacity and Energy Power Purchase Agreement). PG&E's minimum performance requirements are inextricably tied to the type of capacity payment chosen by the QF. These two payment options are described in Section C-5 of Appendix C. ~~as follows:~~

Under Option 1 the monthly payment for capacity, paid in dollars per KW per month, is one-twelfth of the product of the designated per KW annual contract capacity price multiplied by the contract capacity (the amount of energy in kW to be sold and delivered) and by the appropriate loss adjustment factor. In order to receive these 12 equal monthly payments, the QF must meet performance standards which essentially make it dispatchable by

PG&E. Specifically, PG&E requires the QF's contract capacity to be available (dispatchable by or delivered to PG&E) during all on-peak hours of the peak months of June, July, and August, subject to a 20% allowance for forced outages in any month. The contract capacity must also be dispatchable throughout the rest of the year subject to a 20% monthly allowance for forced outages and a designated allowance for scheduled maintenance. During these months other than the peak months, the QF may accumulate and apply the 20% forced outage allowance for any consecutive three-month period. Dispatchability is defined by PG&E as the QF being operable and capable of being called upon at anytime to deliver capacity at any level up to the full contract capacity. The QF must demonstrate that its facility is fueled by a reliable fuel supply and that adequate fuel storage is available to deliver power as requested by PG&E's system dispatcher.

Option 2 provides for payments to QFs, again in dollars per kW per month, for the amount of capacity actually delivered. A formula for calculating this payment is specified in Option 2 and includes a 20% forced outage allowance credit for each month. Although a QF electing Option 2 must deliver its contract capacity to PG&E during the peak hours of the peak months subject to a 20% forced outage allowance, no other performance requirements are imposed for the rest of the year. During the summer peak months, the 20% forced outage limitation and the measurement of performance according to deliveries means that the QF must deliver the contract capacity at least 80% of the peak hours, thus, achieving a peak period capacity factor of 80% during the summer months. During the rest of the year the QF is paid for capacity according to how much energy is delivered, but there is no specified performance level that must be met.

Under Option 1 the QF is dispatchable and has its performance judged according to its availability or ability to deliver whereas under Option 2 the QF is not dispatchable and has its performance judged according to its output or actual deliveries. Also, under Option 2, performance is only judged during the peak summer months whereas under Option 1 there are certain year-round requirements. Apart from these basic differences the remaining provisions of Appendix C are, for the most part, identical for both options. These provisions include a limitation on contract capacity price used to calculate QF payments under either option of 100% of PG&E's shortage costs.

Additionally, to qualify for firm capacity payments, outages for scheduled maintenance (i) cannot occur within the first six months of operation, (ii) cannot occur between May and October unless otherwise agreed to in writing with PG&E, (iii) cannot be undertaken without six months' prior written notice to PG&E's system dispatcher, and (iv) cannot exceed a total of 35 days in any 12-month period. Both options permit capacity payments to continue during the period allowed for such scheduled maintenance.

Section C-3 of Appendix C governs failures to meet the minimum performance requirements. Essentially, this section applies (i) if an Option 1 QF fails to have at least 80% of its contract capacity available during the peak hours of the peak summer months or the allowable percentage, taking into account properly accumulated allowances for forced outages, ~~in other nonpeak months~~, or ~~in~~ (ii) if an Option 2 QF fails to deliver at least 80% of its contract capacity during the peak hours of any of the peak months. If the reason for this failure is other than a forced outage or force majeure, PG&E may immediately suspend the payment of capacity charges for a probationary period not to exceed 15 months. If a QF can meet its minimum requirements during the probationary period, PG&E will pay the QF all capacity payments suspended during the probationary period and reinstate regular capacity payments. If a QF cannot meet the minimum requirements during the probationary period, PG&E may derate the contract capacity to either actual or reasonably expected deliveries, with the quantity by which the capacity is reduced being subject to termination provisions. If the failure to meet minimum requirements was caused by a forced outage,[1/] the QF will ~~have~~ not receive capacity payments ~~suspended only~~ for the month in which this circumstance occurred. During a force majeure, capacity payments will be continued for a period of 90 days following the occurrence.

Finally, PG&E's Appendix C provides no special provisions for any technology other than hydroelectric projects. The only separate provisions for small hydro QFs deal with the determination of the QF's monthly capacity rating. The procedure followed by PG&E mirrors the requirements of D.82-01-103, i.e., with the average dry year being based on the average of the five years of the lowest annual generation as derived from 50-year natural flow data. The small hydro QF is otherwise required to meet the minimum performance requirements for either payment option chosen.

(1) <u>Positions of the Parties</u>

During the hearings and in briefs, both criticism of and support for PG&E's performance requirements were voiced. Generally, IEP, whose views were shared by the State Energy Task Force, found all of the utilities' proposals too rigid and, like the CEC, endorsed statewide performance standards ~~that are~~ which would be more flexible. IEP asserts that PG&E's offer improperly excludes wind and waste-to-energy facilities by imposing overly strict performance standards

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1/ PG&E defines forced outage as any outage resulting from a design defect, inadequate construction, operator error, or a breakdown of the mechanical or electric equipment that fully or partially curtails the electrical output of the QF.

during summer peak periods and inflexible scheduled maintenance requirements. Other parties, including CMA, Calcogen, and Kimberly-Clark, however, endorse PG&E's approach which allows performance to be measured by availability as well as energy production. The staff concludes that, with certain modifications, PG&E's Option 1 is a reasonable model for an offer based on availability.

Parties both supporting and disputing PG&E's general approach, however, also had a number of specific recommendations. To begin with, it was urged that payments above 100% of PG&E's shortage costs should be offered to QFs whose performance exceeds the operating standards normally expected of PG&E plants. The staff suggests that payments should be provided up to 125% of PG&E's ~~avoided~~ capacity costs and should be calculated according to a recommended formula for an additional capacity credit. Staff also suggests that PG&E's definition of dispatchability be modified to give the utility the right to require only increases, not decreases, in a QF's operation and to limit dispatchability to on- and mid-peak periods and emergencies.

IEP and other QFs ask that statewide maintenance standards be adopted which would allow (a) hourly use of the allotted time, (b) an additional 45 days or use of accumulated unused days every three years for major overhauls, and (c) notice requirements related to the amount of time to be used for the outage (i.e., 24 hours' notice for a maintenance period less than 24 hours, seven days' notice for maintenance in excess of 24 hours, and six months' notice for major overhauls). The special needs of waste-to-energy projects ~~who~~ which require 55 days a year for maintenance should also be recognized.

IEP and the staff also argue that all capacity payments should not be suspended during PG&E's probationary period. IEP testified during hearing that such an interruption in cash flow could cause a QF to fail to meet its debt service obligations. Both the staff and IEP recommend that during the probationary period the QF be paid for the actual level of capacity performance it can achieve. At the end of the period, payments should be reinstated based on the level of operation at which the facility can reliably perform. Staff states that the capacity payments suspended for the capacity actually delivered should include an allowance for forced outages.

Finally, a number of the parties recommend that adjustments be made in PG&E's approach for small hydro and waste-to-energy facilities. Staff concludes that since the contract capacity of a small hydro facility is based on the average of five-years low flow during peak months, such a facility should not be further penalized for failing to meet PG&E's peak availability standard in years when flow is less than the five dry year average. Staff recommends that PG&E's performance factor, part of the payment calculation for Option 2 QFs, should be set at 1.0 in establishing the nameplate capacity for small hydro and that the peak availability requirement should be waived.

For waste-to-energy projects, the staff asks the Commission to consider developing over the next year the proper data and methodology required to base capacity payments to waste-to-energy projects on the combined performance of all such projects during the peak months. The group performance would be compared to a utility's baseload plants and the individual waste-to-energy facility would be paid according to its performance as compared to that of the group.

(2) <u>PG&E's Response</u>

In its brief, PG&E asserts that the provisions of its Appendix C are in full compliance with the OIR 2 decisions. Only to accommodate QF development does PG&E suggest any modification of its approach. In particular, it is PG&E's opinion that no adjustments to its minimum performance requirements are necessary for specific technologies, such as wind or solar, since a QF which cannot meet those requirements is less valuable to the utility than one which can. Further, a QF always has the option of signing an as-available contract which was specifically designed to accommodate resource uncertainty.

With respect to payments above 100% of PG&E's shortage cost for QFs whose performance exceeds that of utility plant, PG&E argues that such a payment should only be made to QFs that can actually outperform utility combustion turbines and only if they can do so on a consistent basis. PG&E allows QFs to have a "liberal" 20% peak period forced outage rate under its standard offer but contends that its own peaking units have forced outage rates that ~~a~~ are actually less than this amount. Therefore, for QFs to receive payments in excess of the combustion turbine shortage cost proxy, they must outperform this higher standard of the combustion turbine (i.e., a 10% or 15% forced outage rate). Further, they must commit to ~~do this~~ achieve this performance on a consistent basis.

On the issue of scheduled maintenance, PG&E contends that the standard offer should not become a "lowest common denominator" contract which is stretched to ~~accommodate~~ specific technologies that cannot meet reasonable requirements. For a QF which cannot meet PG&E's requirements, a special agreement or an as-available contract again is always an option. PG&E is willing, however, to allow a QF when it enters the contract either (1) to take only a portion of the allowed number of days per year for scheduled maintenance and combine the remaining days over three years into maintenance periods for major overhauls or (2) arrange an average of 35 days per year over the life of the contract allowing an increasing number of days for maintenance as the project ages.

PG&E is also of the opinion that a probationary period of at least 15 months is necessary to allow PG&E to assess the level of capacity the QF can reliably deliver or make available during the peak months after it has failed to perform. PG&E is willing, however, to redraft its provisions covering the suspension of payments during this period in keeping with the suggestions made by IEP during hearings.

Specifically, PG&E proposes that under Option 1, if a QF fails to meet the minimum performance requirements, it will continue to receive capacity payments for the amount of dispatchable capacity available during the probationary period. If after the expiration of this period, the QF has not demonstrated an ability to provide its full contract capacity to the utility, that capacity will be derated and subsequent monthly payments limited to the new contract capacity. The amount by which the QF's capacity is reduced will be subject to termination provisions.

For Option 2 QFs, the same opportunity to earn capacity payments during the probationary period for the amount of capacity actually delivered will be provided. If the QF fails to deliver the full contract capacity during each of the following year's peak months, the contract capacity will be derated to the lowest monthly amount of capacity actually delivered during the peak months. The lost capacity will again be subject to termination provisions.

Although PG&E claims to disagree with the staff's position on capacity payments to small hydro QFs, its conclusions appear to be in keeping with the recommendations in staff's brief. Specifically, PG&E concludes:

"1. Hydro QFs which have their capacity ratings based on the five dry year average should not have their capacity terminated or derated when their failure to meet the minimum performance requirements is due solely to the occurrence of a dry year which is drier than the five dry year average.

"2. During 'drier' year conditions, capacity payments to hydro QFs should be suspended. Capacity payments should resume, at the contract price, when hydro conditions once again reach the level used to determine the capacity rating." (PG&E's concurrent brief, at pages 31-32.)

b. Edison Standard Offer No. 2 Part I, § 13 (General Terms and Conditions - Availability) and Appendix B. 2 <u>(Capacity Payments for Firm Power Purchases)</u>

Unlike PG&E, which offers payments for firm capacity based on availability or energy production, Edison's standard offer provides only one basis of payment for a firm power purchase - the QF's energy production. [¶ continued next page.]

Basically, under Edison's firm capacity offer, the QF is paid according to its output or capacity factor. In addition, its emergency availability is considered.

The QF's output or capacity factor is taken into account in two ways in the payment provisions ~~given~~ included in Appendix B. 2 of Edison's Standard Offer. First, the QF is paid more for achieving a higher capacity factor, or a level of kWh output that is a higher percentage of the maximum possible kWh output given the kW contract capacity. At an 80% capacity factor the QF is paid 100% of the per kW capacity price for each kW of contract capacity. At higher capacity factor levels, representing performance in excess of that Edison's plants, the price paid per kW is escalated further, up to a maximum of 124% of the basic per kW capacity price for 100% capacity factor performance.

The second way in which output is taken into account is through Edison's "hurdle factor". If a QF output falls below a 50% capacity factor (the "hurdle"), its capacity payment is cut in half for that period. Edison claims that this hurdle factor takes into account QF reliability, because QFs that do not perform within a certain range (greater than the hurdle) are less reliable and less valuable.

The "hurdle factor" is the only aspect of Edison's offer that indirectly requires a prespecified level of output. As noted earlier, under PG&E's output-based option, QFs must meet an 80% summer peak output requirement or face probation and termination of all or part of their contract capacity. Here, QFs must meet a 50% output level in any month (not just peak summer months) or their payments are reduced. Under the Edison scheme, termination penalties would not apply.

Edison's offer also has an emergency availability requirement. Emergency availability is defined in Section 13.2 as follows:

> "At Edison's request seller shall, within 30 minutes of such request, make all reasonable effort to deliver power at an average rate of delivery at least equal to the (contract) capacity... during periods of emergency."

If the QF Seller fails to respond, its capacity payments are reduced by one-half for the six months following the request "until Seller demonstrates (the) ability to deliver full capacity pursuant to Section 13, Part I, or until Seller responds to a subsequent request for full capacity, in which case the six-month capacity payment reduction shall be waived for the remaining reduced payment monthly billing periods." In all cases, however, the reduced payment will apply to the month in which the Seller fails to respond to a capacity request.

In addition to these requirements contained in Appendix B. 2., Section 13 also provides that a QF which fails to respond to an emergency when first requested by Edison will not have its capacity payments reduced. However, after this initial request, whether complied with or not, any subsequent failure by the QF to comply with a request by Edison will result in the aforementioned 50% reduction of capacity payments specified in Appendix B. 2. Failure to comply with a request during an existing six-month reduced capacity payment period will extend that period to six months following the latest failure.

Edison contends that its "availability factor" provides a specific way of valuing QF emergency availability, one of the factors that required by D.82-01-103 ~~calls for~~ to be reflected in the firm capacity payment. The availability criterion is somewhat analogous to the availability required under PG&E's dispatchability option (Option 1) except that there is no allowance for forced outages as in the PG&E's example, and under the Edison's offer the requirement is a part of an output or capacity factor-based payment scheme.

Edison's payment formula also reflects adjustments for scheduled maintenance. Specifically, Edison allows a maximum of 480 hours (20 days) per year for scheduled maintenance and an additional 1,080 consecutive hours (45 days) once every three years for major overhauls. In Part I, Section 8.4, of its offer, Edison defines reasonable advance notice of scheduled outages, including any reduction in capacity availability, as 24 hours for an outage of less than one day, one week for an outage of one day or more, and six months for major overhauls. The off-peak hours are to be used for scheduled and routine maintenance and the QF is required to make reasonable efforts to limits its outages during on-peak and mid-peak periods.

(1) Positions of the Parties

Many of the parties found the same general shortcomings in Edison's offer as PG&E's. For example, QFs complain that here, as in the case of PG&E, many performance requirements are rigid, "all or nothing" type requirements that do not adequately reward partial performance.

In addition, a number of specific criticisms of Edison's offer were raised. In particular, several QFs complain that Edison has failed to make an offer based on availability similar to PG&E's. Staff agrees that Edison should have an availability option. In staff's view, the forced outage rate is the proper performance criterion under such an option. Staff also contends that this availability option should reflect, as Edison's current "output" offer does, a higher payment for operation better than Edison's plants.

QFs note that whereas PG&E's performance requirements would appear to exclude technologies that cannot be dispatchable (Option 1) or meet an 80% summer peak output requirement (Option 2), Edison's offer would not exclude any technologies. In other words, under Edison's offer, there would be no lower limit or absolute eligibility for the firm capacity contract, as even QFs that cannot meet the availability and hurdle factors would receive some capacity payment, however small. Still, many parties object to the hurdle and availability factors as being too rigid and harsh. The deletion or adjustment of these factors is recommended, particularly for certain technologies.

Staff observes that Edison's own plants would have difficulty meeting a 30-minute response time required by Edison for QF emergency availability. Instead, staff argues that Edison should only require that a QF make reasonable efforts to respond to an emergency as soon as feasible consistent with its capabilities. CMA also agrees that technical feasibility is the proper criterion for meeting any emergency and argues that lack of emergency availability should not have such a major impact on capacity payments since it represents only a small fraction of a utility's total avoided costs. IEP suggests that the availability factor should not be applied to a QF on full or partial forced outage which has notified Edison in advance.

IEP recommends that a sliding scale be used in applying the hurdle factor rather than a single 50% capacity factor cutoff. IEP contends that this sliding scale will better reflect the actual level of capacity the QF is contributing to the system. The State Energy Task Force voices the concern that neither the hurdle factor nor the availability factor is applied to Edison's own plants and that these factors require QFs to meet a stricter performance test than utility plants.

If the availability and hurdle factors are to be adopted as proposed by Edison, several of the parties urge that the availability factor be waived for solar (both solar-thermal and solar-photovoltaic) and wind technologies, with wind's nameplate capacity being derated by 20%. For reasons similar to its suggested modifications of PG&E's offer for small hydro, staff recommends that Edison's period capacity, hurdle, and availability factors be set at 1.0 for hydro QFs whose capacity rating is based on the average of the five lowest flow years. For waste-to-energy projects, IEP and the California Waste Management Board ask that these QFs be given a longer time to respond to an emergency consistent with the technology (eight hours) and that the calculation of their capacity payment not include the hurdle factor.

Most parties endorsed Edison's basic approach to the allowed time and notice for scheduled maintenance. IEP, for instance, recommends Edison's offer as a model for statewide scheduled maintenance standards. IEP would only modify Edison's language by increasing the yearly allowance for scheduled maintenance to 35 days. For waste-to-energy projects, the California Solid Waste Management Board again recommends a yearly allowance of 55 days.

(2) Edison's Response

Like PG&E, Edison believes that its performance criteria for firm capacity payments fully comply with the OIR 2 decisions. In particular, Edison asserts that both its availability and hurdle factors are reasonable. Edison argues that QFs that cannot consistently achieve a capacity factor above its 50% "hurdle" are less reliable and less valuable and they should, therefore, have their capacity payment reduced as Edison does in its standard offer. Similarly, Edison believes that a QF ~~that~~ which is not available during emergencies is less valuable and that this situation also ~~too~~ warrants reduced capacity payments.

Edison argues that the emergency availability requirement is appropriate even Edison does not impose a similar requirement on its ~~if the utility's~~ own plant ~~does not have such a requirement~~ and ~~the utility~~ its plant and the QF plant are treated differently. Edison contends that it is appropriate to treat the two differently since they have different obligations. The utility, by virtue of its retail franchise, has an obligation to serve customers at all times whereas the QF has no incentive beyond price to serve Edison's ratepayers during emergencies. Edison contends that the 30-minute response time that it requires for QF emergency availability is reasonable and that any adjustments to this requirement should only be considered on a case-by-case basis.

Edison does offer to modify the application of its hurdle and availability factors for specific technologies. In particular, Edison has adopted the adjustments suggested by the staff for wind, solar, and hydro with the exception of retaining the period capacity factor for small hydro to permit the capacity payment to be based on actual performance.

Edison also states that it is willing to pay QFs in dollars per kW per month based on availability, but only if the QF is fully dispatchable and its as reliable as Edison's generating resources. According to Edison this dispatchability and reliability will require (1) an accurate measurement of QF availability during each time period for each season; (2) detailed, accurate, and verifiable QF records with periodic company review to determine a QF's actual energy production; (3) a QF being the functional equivalent of an Edison combustion turbine or the purchased power used by Edison to develop its shortage costs; (4) a QF's performance being measured individually and not in the aggregate; and (5) full dispatchability permitting the utility to increase and decrease generation. As in the case of PG&E, staff disagrees with this view of dispatchability and recommends that Edison should not have sole discretion over a QF's operation and should be allowed only to require increases in a QF's production or availability.

In recognition of the wide variation of QF's scheduled maintenance requirements, Edison endorses modification of its standard offer to allow more flexibility in scheduled maintenance allowances. Specifically, Edison will provide 35 days of scheduled maintenance per year and a year-to-year accrual of unused maintenance days, not to exceed 45 days.

c. SDG&E Standard Offer for Firm Capacity, Section 6 (Purchase Price of Energy and Capacity) and Exhibit C (Capacity Payment Schedule for Firm Capacity QFs)

SDG&E offers two payment options to QFs signing its firm capacity contract. Both options, set forth in Exhibit C of the offer, are based on energy production, as opposed to availability, and the choice of capacity payment option is limited by the payment option selected for the QF's sale of energy to SDG&E. If a QF elects energy Option 1 (as available energy), it will be paid for capacity only according to capacity Option 1. A QF choosing energy Option 2 (five-year forecast) can be paid for capacity under either capacity Option 1 or 2. The two options for capacity payments are based on two different performance criteria which must be met for payment.

Under Option 1, capacity payments are made on the basis of the QF's output or energy ~~production~~ actually delivered. A QF~~s~~ starts with a certain levelized annual capacity price in dollars per kW which varies depending on the length of the contract that the QF ~~they~~ signs ~~up for~~ and the ~~their~~ year its operation ~~of~~ start~~up~~s. This annual price is spread to different hours within the year based on a "supply factor", an allocation factor that values capacity more during seasonal or daily peak demand hours. The resulting ¢/kWh capacity prices for different time periods are paid to the QF for all the kWh energy output that it provides in each time period. There are no pre-specified output or availability performance levels that must be met. There are no conditions or limitations on scheduled maintenance.

Option 2 is entitled Payment by Capacity (\$/kW-month). Under this option, payment is based on output or capacity factor and requires that certain peak period performance standards ~~requirements must~~ be met. The Option 2 monthly capacity payment equals the product of the Equivalent Capacity Factor (ECF) and the appropriate \$/kW number in the capacity table again determined by the length of the contract and the QF's operation date. The ECF is calculated as follows:

$$ECF = \frac{Q \times A}{C \times (H-S) \times R}$$

Under this formula, Q represents the delivered energy in kWh during monthly on-peak and semi-peak time periods; A is a monthly capacity allocation factor differentiated by season; C is the contract capacity; H stands for the total monthly on-peak and semi-peak hours; S is a QF's monthly scheduled maintenance during on-peak and semi-peak hours, which is not to exceed 75% of H; and R is the reliability of SDG&E's system alternative capacity source. R currently has a value of 0.85.[21]

21/ SDG&E bases this 85% reliability on its own peaking plants, which it asserts have, at most, a 15% outage rate.

To be paid under this formula, a QF must (a) deliver enough output during peak and semi-peak hours of the month so that the monthly ECF is greater than 0.5 and (b) schedule outages at least six months in advance during periods acceptable to SDG&E. Scheduled outages must not exceed 720 hours (30 days) in any 12-month period. Agreed dates for scheduled maintenance cannot be changed without notice.

If the QF fails to meet the minimum performance provisions set forth in Exhibit C, SDG&E will immediately suspend or reduce the capacity payments to the QF for a probationary period. The terms and conditions of this suspension, set forth in Section 16.5 of the standard offer, are similar to those in PG&E's standard offer, except that the probationary period is not to exceed 14, as opposed to 15, months.

(1) Positions of the Parties

Unlike their response to the offers of the other utilities, a number of QFs, generally represented by IEP, endorse SDG&E's approach and urge its adoption for both PG&E and Edison.[3/] IEP believes that SDG&E's two-option contract will appeal to a wide variety of QFs. in IEP's opinion, ~~IEP believes that~~ SDG&E's Option 1 ~~rightly~~ correctly recognizes the valuable contribution which a QF can make to the utility system just by signing a long-term commitment. Although a QF could achieve a higher payment agreeing to the more stringent requirements of Option 2, a QF who agrees to Option 1 will receive

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3/ IEP specifically suggests that PG&E's and Edison's offers would be acceptable if an option like SDG&E's Option 1 were also part of those offers.

a payment 15% below that of an Option 2 QF simply by making a long-term commitment.4/*

Other parties, however, did find ~~certain alleged~~ deficiencies in SDG&E's offer. ~~certain respects.~~ Among other things, several parties ~~First, it was~~ pointed out, ~~and~~ that SDG&E does not have an option (such as PG&E's) which values QF's performance based on availability rather than energy production. Further, ~~Secondly,~~ it was claimed that SDG&E does not allow payment above the 100% shortage cost level for QFs that exceed the performance of utility plant. Staff contends that under Option 1 ¢/kWh payments, a QF that achieves a 100% capacity factor, a performance level better than utility plants, will only receive 100% of the combustion turbine capital cost proxy, not some higher level. Staff would have the Option 1 QF receive 100% of the shortage cost proxy for 80% capacity factor output, and 125% for 100% output. Similarly, under Option 2, staff would have the QF receive 100% of the capacity price for an 80% capacity factor, rather than 85% as now specified by the reliability factor, R. Use of the 80% standard by staff is based on their estimate of the average reliability of SDG&E's plants or its system as a whole.

None of the parties suggested any adjustments to SDG&E's payment options or performance requirements for specific technologies. Comments regarding PG&E's suspension of payments provisions and scheduled maintenance allowance were equally applicable to SDG&E.

4/* QFs under Option 1 receive 100% of the $/kW annual capacity price for a 100% capacity factor during the year, while QFs under Option 2, by virtue of the "R" in the formula listed above, receive 100% of the $/kW annual capacity price for an 85% capacity factor performance.

(2) SDG&E's Response

SDG&E is willing to modify its firm capacity offer so that the choice of capacity option will not be limited by the type of energy payment chosen. However, SDG&E concludes that both its capacity payment Options 1 and 2 are reasonable and consistent with OIR 2. According to SDG&E, Option 1, ~~which~~ reflects an aggregate value of firm capacity and is intended for QFs which are unable or do not desire to guarantee a minimum degree of availability. Under these circumstances, Option 1 will be a useful tool in making the standard offers widely applicable to QFs. SDG&E acknowledges, however, that the factors recited in D.82-01-103 for inclusion in a payment for firm capacity are actually contained in its capacity payment Option 2.

With respect to Option 2, SDG&E does not believe it is necessary to have an availability option under which ~~wherein~~ the QF is dispatchable. SDG&E concludes that it would be impossible to measure availability when it is not based on actual output, but is ~~and must be~~ based on a measure of forced outages and the potential to produce output. Further, SDG&E argues that its Option 2 is ~~based sufficiently on~~ actually reflects availability since ~~in that~~ it requires QFs to produce a certain amount during peak and semi peak hours. ~~and when such production occurs the QFs are obviously "available".~~ ~~It's~~ SDG&E's minimum ECF of 0.5 under Option 2 is a standard of peak period reliability and availability.

SDG&E disagrees with staff's contentions about payments above 100% of the shortage cost. For Option 1 type QFs, SDG&E argues that they are less reliable and therefore should only receive a maximum of 100% of the shortage cost for 100% capacity factor output (similar to the as-available capacity payment). For Option 2 QFs, SDG&E argues that payments above 100% are allowed for capacity factor performance above 85%. This 85% standard is based on a conservative assumption of ~~their~~ its combustion turbine plants' reliability. ~~They~~ SDG&E

disagree with staff's use of an 80% standard, as it incorrectly is based on system reliability rather than peak or plant reliability. Use of the latter standard appropriate in order to be consistent with the ~~The latter should be used, they say, because it is the plant used as the~~ shortage cost proxy approach.

SDG&E offers no changes to its provisions governing suspension of payments or scheduled maintenance. SDG&E observes that its scheduled maintenance allowance is already sufficiently flexible, particularly since ~~the~~ restrictions on maintenance only apply ~~to maintenance conducted~~ during peak and semi-peak periods.

d. Discussion

In D.82-01-103 the utilities were directed to draft a firm capacity contract, designed for QFs that could meet certain operating standards, and an as-available capacity contract, designed for QFs that could not, or did not desire to, meet such standards. The operating or performance standard, envisioned in D.82-01-103 for firm capacity QFs was to be a standard which required QF availability during system peak periods. The standard was to be designed to reflect aspects of peak period availability such as dispatchability, reliability, availability during emergencies, scheduling of outages, and contract duration, termination, and sanctions. QFs that signed ~~an~~ contracts as firm power sources were to meet this ~~un~~specified standard of performance.

We have before us three general types of performance standards in the utilities' filings. The first is a performance standard based on a level of peak period availability ~~that a QF must meet~~, as ~~This is~~ exhibited by PG&E's Option 1. The second is a performance standard based on a level of peak period output ~~that a QF must meet.~~ ~~This is~~ as exhibited by PG&E's Option 2, SDG&E's Option 2, and Edison's single ~~[illegible]~~ payment offer. The third is a performance standard that requires only a commitment to a certain contract length ~~[illegible]~~ with ~~and~~ no specific peak period output or ~~or~~ availability. This approach is embodied in ~~is~~ SDG&E's Option 1.

We find that PG&E's Option 1 availability standard, with ~~certain~~ the modifications discussed below, is in compliance with the requirements of D.82-01-103. Indeed, as ~~the language of that decision is~~ the requirements of D.82-01-103 are oriented towards ~~requiring~~ QF peak period availability, this availability type of standard most clearly follows from ~~our earlier~~ this decision. Under this option the QF is dispatchable and available for emergencies. Moreover, because of the limitations on peak period forced outages, peak period reliability is assured. Nonperformance is deterred ~~[illegible]~~ the application of termination ~~[illegible]~~ provisions. Requirements are made for scheduled maintenance.

All three utilities have proposed a performance standard that is based on a QF ~~[illegible] of~~ achieving a certain level of peak period output. D.82-01-103 specifically allows for a performance option ~~[illegible]~~ based on capacity factor or output, rather than ~~of~~ availability. Output requirements are an indirect way to assure availability for nondispatchable units.

~~The [illegible] we will discuss in [illegible].~~ We consider ~~[illegible]~~ PG&E's Option 2 with ~~certain~~ the modifications discussed below, to be in compliance with D.82-01-103. Under this option the QF must deliver its contract capacity to PG&E at least 80% of the time during the peak hours of the peak summer months. During other periods there are no ~~pre~~specified performance requirements, other than scheduled maintenance limitations.

Turning to the aspects of peak period availability required in ~~taken from~~ D.82-01-103, ~~[illegible]~~ it is clear that ~~under [illegible]~~ the peak period output requirement in PG&E's Option 2 assures reliable operation during the hours of the year ~~where~~ when reliability is most important. The QF under Option 2 is not dispatchable, but the peak period output requirement and the general weighting of capacity prices toward peak and semi-peak hours assures that QFs will operate during most, if not all, of the same periods as they would have had they been under the dispatcher's control. D.82-01-103 specifically allows for non-dispatchable QFs to be accommodated in the firm standard offer. Time-of-use pricing and peak period output requirements under Option 2 will also assure that QFs will be delivering their capacity during the most likely emergency periods. Finally, maintenance scheduling and ~~provisions for~~ termination provisions apply ~~here~~ as they do in the case of PG&E's Option 1.

The essential ~~aspect of the standard of~~ requirement of performance under both PG&E's Options 1 and 2 is the 80% summer peak hour availability or output requirement. IEP has argued that this standard is too stringent and ~~is~~ one that many utility plants could not meet. We consider the standard to be reasonable for QFs that sign up as firm sources and receive capacity payments based on the combustion turbine. Evidence in ~~the~~ this proceeding, with which IEP concurred, indicated that utility peaking plants, such as combustion turbines, have an average peak period availability of greater than 80%.

We do agree with IEP that PG&E's options are too stringent in other ways, such as ~~the~~ its requirements for scheduled maintenance. As discussed below, we will require certain changes ~~on~~ with respect to this and other ~~features~~ performance requirements.

IEP also argues that ~~the~~ an 80% peak availability or output requirement is too inflexible and is of an "all or nothing" nature. We disagree. Under the reduction in payment provisions ~~that~~ which PG&E proposed in its brief, discussed below, a QF that does not achieve the 80% availability or output standard will still receive a payment commensurate with its actual production. and will have the opportunity to have its original capacity payment reinstated if its availability or output reaches the 80% level during the probationary period.

The flexibility of the standard is also enhanced because it may, if need be, only apply to part of the QF's total capacity. In other words, if a 10-MW QF facility produces consistently at a 5-MW level and sporadically at higher levels, the QF can sign up for 5 MW of firm capacity (which meets the 80% standard) and sell the rest of its output on an as-available basis. ~~(where capacity payments, albeit smaller ones, also apply).~~

SDG&E's Option 2 is, like PG&E's Option 2, ~~an~~ based on the QF's output ~~based performance standard~~. In certain cases, however, the option imposes a ~~it is~~ more lenient ~~than~~ performance standard than PG&E's ~~standard in that it only requires~~ by requiring only a 50% output level ~~and~~ which the QF may fail to meet and still not be exposed to ~~does not lead to probation and possible~~ termination ~~sanctions if the standard is not met~~ or probation provisions. On the other hand, ~~it~~ the 50% standard applies to peak and semi-peak hours during all months of the year, not just summer month peak hours. ~~Also, it does not allow~~ Partial capacity payments are also not allowed for performance that is somewhat below the standard. If the 50% level is not met, the QF receives ~~6%~~ no payment for that month.

We ~~cannot~~ do not find SDG&E's Option 2 to be in compliance with D.82-01-103. The 50% standard is, in our view, not an adequate level of peak availability and reliability, even if it does apply to more hours of the year. The firm capacity performance standard should be oriented toward the system peak hours ~~where~~ when reliability is of greatest concern. It should be a level of reliability that is commensurate with the utility plant that is avoided by QF purchases. Utility plant has a higher level of peak period availability than 50%. Also, it is more reasonable, in our view, to allow more flexibility than SDG&E allows by giving partial payment, rather than zero payment, for performance below the standard. ~~rather than zero payment.~~ Further, ~~the~~ SDG&E's zero payment for nonperformance ~~provision~~ does not differentiate between temporary and repeated nonperformance. More flexibility should be allowed for temporary nonperformance, ~~and~~ with ~~sanctions and~~ termination provisions ~~should apply~~ applied only to continued ~~to repeated~~ nonperformance.

We also find that Edison's output-based performance standard is not in compliance with ~~the intent of~~ D.82-01-103: Edison's basic performance standard is a 50% output level, incorporated ~~[illegible]~~ in its "hurdle" factor. In ~~the~~ Edison's offer this standard applies to all periods - peak, mid-peak, and off-peak - in all months of the year. ~~Noncompliance~~ Failure to meet this standard results in a 50% reduction in the capacity payment. ~~Also~~ Edison also requires ~~[illegible]~~ emergency availability, ~~[illegible]~~. ~~[illegible]~~ Failure to meet this standard - ~~[illegible]~~ results in an additional ~~a~~ 50% reduction in the payment. ~~also~~

~~The~~ Edison's performance ~~standards~~ ~~is~~ do not adequately focus~~es~~ on peak period availability as ~~[illegible]~~ required by D.82-01-103. Apart from the emergency availability requirement, there is little differentiation between required peak and off-peak performance. ~~and~~ The 50% output level is ~~[illegible]~~ is also too lenient for the peak period. On the other hand, ~~[illegible]~~ the emergency availability requirement, ~~it~~ is too stringent and places too much emphasis on one aspect of peak period availability. It is for these reasons that we find that Edison's performance requirements for firm capacity QFs do not comply with D.82-01-103. ~~[illegible]~~

The final type of performance standard that we must consider is ~~[illegible]~~ SDG&E's Option 1. This ~~standard~~ option appears to be a hybrid of the standard offers approved in OIR 2, an offer which could ~~[illegible]~~ lead essentially to a long-term as-available capacity contract. Although a QF ~~[illegible] in~~ electing SDG&E's Option 1 ~~[illegible]~~ would be committing its resource for a specified period of time at a price which would vary by time of energy delivery, the QF would not be required either to be available during peak periods and emergencies or to match the reliability of SDG&E's own plants. We understand the reasons many QFs have found such an option desirable, i.e., the opportunity to have payments which would be levelized and possibly greater than those paid an as-available producer. Nevertheless, Option 1, failing to reflect the required performance standards, is not an option to purchase firm capacity as defined in D.82-01-103. While we might consider such a hybrid in the future, it was ~~not~~ neither contemplated ~~in that order and is not~~ by nor in compliance with that ~~order~~ decision.

Because of our conclusions, it will be necessary for the utilities to refile their standard offers in conformance with this order. Although we believe that PG&E's Options 1 and 2 can serve as appropriate models for firm capacity standard offers based on availability and energy production, even these offers require modification. ~~Further~~, Neither SDG&E nor Edison will have compiled with the OIR 2 decisions until each offers ~~a~~ payment options based on a QF's availability and energy production equivalent to ~~that~~ those offered by PG&E, as modified herein. ¶ To achieve overall compliance with this decision and OIR 2, the following principles should ~~also~~ be incorporated in the utilities' firm capacity standard offers:

(1) Dispatchability. We concur with the staff that the definition ~~for~~ of dispatchability used in PG&E's Option 1 and any other offer based on availability should give the utility the right to require only increases, not decreases, in a QF's operation. At this time the language employed by PG&E (required capacity deliveries "at any level up to the full contract capacity") is ambiguous, but appears to permit both upward and downward dispatchability. We agree with the staff that the ability of a utility to interfere with a QF's operations in such a manner is unwarranted and unreasonable. The utility should not be in a position to unilaterally jeopardize a QF's operation and in turn reduce its payments. Regarding dispatchability, D.82-01-103 ~~our prior order~~ required only that a QF be sufficiently dispatchable to be available for a utility's increased needs during peak periods and emergencies. For these reasons, we also find Edison's approach to dispatchability too restrictive.

We do not believe it is necessary, however, to define dispatchability as limited to on- and mid-peak periods and emergencies if an approach like PG&E's is used. Such a limitation is both implicit and explicit in PG&E's Option 1. For the peak months, a QF signing Option 1 is required to have 80% of its capacity available only during the peak hours and for the remainder of the year need only maintain a somewhat flexible forced outage rate. Because PG&E offers no method for checking on a QF's ability to respond in every hour of each day, but rather uses an on-call approach, ~~such~~ a QF will at least have the minimum ability to respond consistently to system emergencies which cannot be predicted.

While we could adopt Edison's response-time (30 minutes) criterion for emergencies, we believe that the record in this proceeding is not sufficient to designate a specific response time for all utilities and that PG&E's requirements essentially accomplish this same result by ensuring a QF's readiness to perform. The only time PG&E would possibly need to increase a QF's supply is at times when its own demand increases (i.e., peak, semi-peak, and emergencies). PG&E's approach allows a QF to meet all of these performance factors without placing an unreasonable burden on a QF's operation or one inconsistent with PG&E's plant operations.

(2) <u>Payments in Excess of a Utility's Capacity Costs</u>. We conclude that an option is not in compliance with D.82-01-103 or this order unless it provides for payments in excess of a utility's capacity costs to QFs whose performance exceeds that of the utility's plants. We do not believe that a firm capacity QF must be the exact functional equivalent of a utility's peaking combustion turbine to receive an offer based on 100% of a utility's capacity costs. However, we do agree with PG&E that to receive higher payments the QF's consistent level of performance should exceed the minimum level of availability of the peaking unit used as a proxy to calculate the utility's shortage costs. Such a requirement will ensure that the utility will not pay more than its avoided costs, the previously determined level of payment found reasonable for QF purchases.

Testimony during hearing indicated that the availability factor of a combustion turbine could range from 80% to 94%. To receive higher payments, a QF should at least meet a comparable level of performance during the utility's peak periods. We believe that it is reasonable, therefore, to require that a QF achieve a peak period availability or capacity factor in excess of 85% before receiving capacity payments in excess of 100% of the shortage cost proxy. Thus, a utility's payment options should include an offer to pay a price higher than the utility's stated capacity costs for those QF's (1) who demonstrate an availability of 85% or better during time periods similar to those specified in PG&E's Option 1 or (2) who deliver capacity during the peak periods at a capacity factor of 65% or better under an output option like PG&E's Option 2. Under these circumstances, a QF who performs at this higher level could receive up to 118% of a utility's shortage cost. ~~for availability ...~~

We believe, however, that an additional requirement should be imposed in an availability option which permits the higher payment. PG&E currently intends under its Option 1 to measure a QF's dispatchability by placing the QF "on-call". We believe ~~however~~ that a more certain measure of the QF's dispatchability should be required if a QF is to receive payments above a utility's avoided costs in order to ensure whether and at what level the QF actually exceeds utility plant operations. Such a demonstration is therefore required not only to justify the higher payment, but to determine the appropriate level of that payment.

For this reason, we will direct the utilities to include in their standard offers a reasonable method of determining the QF's consistent ability to be available at a forced outage rate of 15% or less. Although SDG&E argues that more operating experience is required to determine a QF's forced outage rate, ~~we~~ it is our view ~~believe~~ that having set the standard (performance at an availability factor of 85% or better) the utility can devise methods to review the QF's actual performance. It is only in this case of higher payments that Edison's reporting requirements which it felt were necessary for a QF to be dispatchable might be appropriate.

(3) Adjustments for Specific Technologies. Edison proposed certain adjustments in its firm capacity performance standards for solar and wind technologies. Basically, Edison is willing to ~~will~~ waive its emergency availability standards for both technologies and waive the 50% "hurdle" or output standard for wind. under these circumstances, ~~[illegible]~~ the capacity payment for wind would be reduced by 20% while the solar payment would ~~not~~ be unaltered ~~[illegible]~~. As we have not found Edison's performance standard to be in compliance with D.82-01-103, these modifications ~~[illegible]~~ are essentially ~~moot~~ irrelevant. As discussed earlier, we believe that the performance standard that we have adopted, modeled after that proposed by PG&E, ~~standard offer,~~ offers sufficient flexibility for QFs that can meet a specified level of performance. QFs ~~that~~ which cannot meet ~~a~~ the specified level of performance can sign an as-available capacity contract or enter into negotiations for a nonstandard ~~offer~~ contract.

D.82-01-103 did provide ~~the~~ a special capacity price adjustment, however, for small hydro facilities. We do find that some clarification of ~~the~~ this adjustment ~~[illegible]~~ is required. Based on the discussion in staff's brief, it now appears that staff and PG&E are actually in substantial agreement regarding the conditions to be applied to small hydro facilities operating in a "drier" year than the five dry year average.

We find the recommendation made by PG&E in response to this issue, recited supra, to be reasonable with one exception. In its brief PG&E has suggested altering its contract provisions governing the suspension of payments for failure to meet ~~the~~ its minimum performance requirements. Instead of suspending all payments, PG&E will modify its offer to specifically permit payment for the capacity actually delivered during the probationary period. Because we intend to adopt this approach, we believe it is consistent to permit hydro QFs operating ~~[illegible]~~ during the "drier" year to be paid for the amount of capacity, if any, actually delivered to the utility during ~~the~~ the "drier" year period, ~~[illegible]~~ Following the "drier" year, the QF's capacity payments will be reinstated or reduced depending on the level of performance it achieves, consistent with PG&E's reduction in payment approach. [¶ continued next page.]

With this modification PG&E's recommendation should be included in every utility's firm capacity standard offer for hydro QFs whose payments are based on the five dry year average.

(4) Scheduled Maintenance. As in the case of availability requirements, we believe that scheduled maintenance requirements in the firm capacity offer should be reasonably consistent ~~across~~ between utilities. We agree with PG&E that our standards for firm capacity should not be formulated based on the "lowest common denominator" and should not jeopardize avoided cost value. However, we also conclude that scheduled maintenance standards should be sufficiently flexible to permit various types of QF operation. Essential elements of ~~a~~ any scheduled maintenance ~~[illegible]~~ allowance should be ~~are~~ (1) a reasonable allotment of days for both routine maintenance and major overhauls, (2) sufficient notice to aid utility system planning, and (3) appropriate timing to avoid periods of greatest demand on the utility system.

We believe that these basic principles are embodied in Edison's approach to scheduled maintenance with certain modifications. Therefore, an offer which complies with this decision and OIR 2 must allow the following:

> a. Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis.

b. A QF may accumulate unused maintenance hours on a year-to-year basis up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls.

c. Reasonable advance notice to the utility of a scheduled outage will be 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for a major overhaul), and six months for a major overhaul.

d. Major overhauls shall not be scheduled during the peak summer months. Reasonable efforts to schedule or reschedule routine maintenance outside the peak summer months should also be made, but in no event shall outages for scheduled maintenance exceed 30 peak hours during the summer peak months.

e. No restrictions should be imposed on the use of the scheduled maintenance allowance during the initial period of operation (i.e., the first six months).

(5) Reduction of Monthly Payments. For payment options based on either availability or energy production, we generally adopt PG&E's altered approach for reducing payments following a failure to meet the utility's minimum performance

requirements. PG&E's original proposal provided that such a failure would result in a total suspension of capacity payments for up to 15 months. Its modified approach, however, would permit payments for capacity actually delivered during the probationary period with the potential of the original payment level being reinstated or the QF's capacity derated at the end of that time depending on the QF's performance during the peak months. If the QF is unable to deliver its promised firm capacity, the utility should have the ability, as suggested by PG&E, to make that determination over a reasonable period of time. Given the peak month periods of all three utilities, a probationary period of 15 months is reasonable.

Within that time, however, the QF should not experience a total cessation of cash flow if it has a capacity contribution ~~or~~ to make to the utility's system. The complete suspension of monthly payments when this circumstance exists is an unreasonably harsh penalty to impose on a QF whose failure to perform may have resulted from its level of operation during a single peak month. To permit the QF to continue to be paid for capacity actually delivered during the probationary period is a necessary and reasonable part of a more flexible performance requirement.

We agree with PG&E that the QF's ability to meet the minimum performance requirements in peak months following its failure should be used to determine whether its original capacity payment will be reinstated or its contract capacity derated. The difference between the contract capacity and the reduced capacity is appropriately subject to contract termination provisions. In using this approach, no retroactive payment ~~will~~ at the end of probation would be necessary. ~~Finally,~~ We also adopt staff's recommendation that, for the capacity actually delivered during the probationary period, an allowance or credit for forced outages at the level otherwise specified in the agreement should be included.

(6) As-Available Capacity Payments <u>Prior to Firm Capacity Delivery</u>

During hearing one additional recommendation was made by IEP witness Philip M. Huyck, which although not strictly a compliance issue, does relate to the performance required under a firm capacity contract. It was Huyck's suggestion that QFs under a firm capacity contract who produce energy during start-up periods before the facility is ready to begin delivery of firm capacity should receive an as-available capacity payment up to the time that ~~we~~ they firm capacity operations commence. Although PG&E and Edison agree in general principle with this proposal, staff asserts that the theoretical basis which supports a payment for as-available capacity does not exist for such a payment during a start-up period. Because of the generally short period involved for start-up and the fact that a utility would probably not have a large number of generating plants in start-up at the same time, there can be no aggregation of energy, as in the case of as-available capacity, to serve as the basis for the utility avoiding capacity costs. Staff suggests that under these circumstances only as-available energy payments should be allowed.

After reviewing IEP's recommendation, we find SDG&E's response to this issue to be the most appropriate. Specifically, SDG&E states at page 21 of its concurrent brief:

> "...If a QF has declared an Operation Date, which is defined to be the date the plant is deemed to be capable of reliably delivery of energy and capacity..., the QF will be expected to provide capacity from that date. If the QF is unprepared to deliver capacity at the Operation Date, a different date should be chosen. If the QF anticipates there will be start-up problems, but believes it is entitled to receive some capacity

> payments, SDG&E suggests that the QF execute an as-available contract of short duration to cover the period in which the QF anticipates start-up difficulties. When the QF is confident that it can provide firm capacity, [it] can commence performance under a firm capacity contract."

By adopting this approach, no additional provisions will be required in the firm capacity contract which might be in conflict with the basis of that offer or, as pointed out by the staff, the theory of an as-available capacity offer. SDG&E's suggestion illustrates the existing options available to a QF under the offers we have already approved.

2. Termination Provisions

While D.82-01-103 specifically included contract termination as a factor to be reflected in firm capacity offers and payments, the decision set forth no specific guidelines governing such provisions. The utilities have properly responded to OIR 2 by including termination provisions in each of their firm capacity standard offers. Within these provisions are liquidated damage clauses intended to reimburse the utility for unearned capacity payments made to QFs and, in some cases, the utility's costs of replacing the lost capacity. Certain of the offers place a value on, and in turn propose a reduction in the damage amount for advance notice of termination.

In addition to issues related to ~~generated by~~ the damage clauses of the utilities' standard offers, some of the QFs questioned the application of termination provisions to a conversion from a simultaneous purchase and sale of energy ~~arrangement~~ to a sale of surplus only. The proposals of the utilities and the views of the other parties on each issue are summarized below followed by our resolution of the particular issue.

a. Damage Clauses

(1) PG&E - Standard Offer No. 2, Appendix D

PG&E's standard offer for firm capacity distinguishes between two types of termination: termination with prescribed notice (Appendix D. Section D-2) and termination without prescribed notice (Appendix D. Section D-3). The length of the prescribed notice is directly related to the amount of the contract capacity being terminated or reduced. This notice ranges from three months for 1,000 kW or less to 60 months for over 100,000 kW.

In the event the prescribed notice is given, the QF terminating its contract is only required to refund to PG&E an amount equal to the difference between the capacity payments already paid by PG&E and the total capacity payments which PG&E would have paid based on the period of the QF's actual performance (i.e., repayment of overpayments in the early contract years that arise from levelization of the capacity price). Interest is to be paid on the refund at the prime rate as published by the Bank of America. For the amount of capacity terminated, the QF will receive, from the date of notice to the date of actual termination, capacity payments based on the capacity price adjusted to the period of the QF's actual performance.

For termination without prescribed notice, a QF is required to make the refund described above, as well as the following additional payment:

> "Seller shall pay PGandE a one-time payment equal to the amount of contract capacity being terminated times the difference between the current capacity price on the date of termination for a term equal to the balance of the term of agreement and the contract capacity price, pro-rated for the length of notice given, if any, by multiplying by one minus the ratio of the actual number (as set forth in paragraph D-2). In the event that the current firm capacity price is less than the contract capacity price, no payment under this paragraph D-3 shall be due either Party." (Section D-3.)

In support of its termination provisions, PG&E points out that the levelized capacity payments made under a firm ~~capacity~~ capacity contract provide a steady revenue stream to the QF with a greater portion of the contract income being received in the early years. Without full contract performance, overpayments should be recaptured to ensure that the QF is only paid based on the costs the utility actually avoided from the QF's operation. In PG&E's view, interest on this refund is reasonable in recognition of the time value of money.

PG&E also believes that its method of calculating damages for termination without adequate notice is consistent with the principles of contract law. Specifically, PG&E contends that it has used an established measure of damages: the difference between the contract price and the replacement cost. According to PG&E, the presence of this provision also serves to encourage QFs to give adequate notice of termination, while limiting the damages caused by a QF to one year's worth of the replacement cost differential.

(2) Edison - Standard Offer
No. 2, Part I, Section 5

Under Edison's standard offer, a QF terminating the agreement is required to reimburse Edison for unearned capacity payments according to the following formula: (1 - X/N) times the total value of capacity payments paid to date of termination, where "X" is the number of completed years of service from the initial firm capacity delivery date and "N" is the firm contract length. No specific formula is designated for damages associated with Edison's replacement costs. Edison also requires a QF to provide evidence, "to Edison's satisfaction," of its ability to make potential termination payments.

Edison defends its approach, which places no value on advance notice, as requiring the contracting parties to live up to their obligations unless uncontrollable forces intervene. Edison is critical of contract provisions permitting a QF to "buy out" the remaining term of its contract, i.e. PG&E's proposal, since such provisions will encourage QFs to ignore their obligations. According to Edison, whenever a QF terminates, even with notice, the utility and its ratepayers are damaged at least to some extent by the utility having delayed or eliminated construction because of a QF's availability.

(3) SDG&E - Firm Capacity Standard Offer, Section 16

SDG&E's firm capacity standard offer includes termination provisions similar to PG&E's contract. A distinction is made between a QF terminating with prescribed notice, for which the basis for reimbursement is specified (Termination Payment A, Section 16.2) and termination without prescribed notice, for which an additional one-time payment is required (Termination Payment B, Section 16.4). The major differences between the two utilities are SDG&E's notice periods (ranging from 12 months for 5,000 kW to 60 months for 20,000 kW or more), its adopted interest rate (simple interest of 12% per year), and its calculation of replacement damages. With respect to the latter difference, Termination Payment B is the sum of Termination Payment A and a one-time payment calculated by taking an adjusted capacity price, based on the QF's actual performance, and inflating that figure by 1% per month for the period of the QF's performance. This figure minus the original firm capacity price is then multiplied by the ~~amount~~ number of KWs terminated by the QF.

SDG&E supports its approach on grounds similar to those urged by PG&E. SDG&E also points out that adequate notice has a value since it permits the utility sufficient time to purchase or construct additional capacity. SDG&E does note, however, that only to enhance certainty in the contract terms did it adopt a simple interest rate of 12% per annum. Further, in SDG&E's view, while its method for calculating its one-time Termination Payment B is reasonable, its complexity might require a different approach, preferably that suggested by the staff below.

(4) Staff

The staff's proposed termination provisions are designed to reflect the principles that (a) standard offers should specify the consequences of a QF's termination; (b) termination provisions should encourage QFs to fulfill their contracts, but also encourage the QF to provide sufficient notice to allow a utility to replace the lost capacity; and (c) damages for termination should be calculated to make the utility and ratepayer whole. Guided by these principles, the staff adopts an approach that is somewhat similar to those proposed by PG&E and SDG&E.

Specifically, the staff endorses the distinction between QFs which provide adequate notice and those which do not. Staff adopts the notice periods proposed by SDG&E and the general concept of the recovery of overpayments with interest calculated at the prime rate as determined by a common reference source. According to the staff, however, the additional payment required of a QF which fails to give the minimum notice should equal ~~to~~ 50% of the amount of the capacity overpayment ~~of capacity~~ calculated without accrued interest. The full "penalty" should be reduced in direct proportion to the length of notice the QF gives as compared to the prescribed notice period. Staff argues that the ~~second lack of notice type of~~ penalty should be based on a number that is known at the time the contract is signed, not an uncertain future capacity replacement cost figure. Staff therefore bases the additional payment required of QFs who fail to give adequate notice to ~~its lack of notice penalty on~~ the ~~levelization~~ overpayment to be refunded ~~penalty~~, ~~the latter of~~ a payment which could be calculated for different termination dates at the time the contract was ~~is~~ signed.

Staff also urges that a probationary period like that prescribed by PG&E should be applied by all the utilities not only to failures to deliver contracted capacity, but also to failures to maintain QF status or pertinent governmental authorizations, permits, and licenses. With respect to the latter failures, the 15-month period would provide time within which to correct those deficiencies without a QF risking total contract termination.

The staff also argues that a QF should not be required to provide evidence of its ability to make potential termination payments. Finally, the staff recommends that the utilities should ~~also give~~ include clear examples in the standard offer of the operation of their termination provisions.

(5) Other Parties

CMA urges that the staff's recommendation of a "50% penalty" for early termination be rejected as arbitrary. According to CMA, the QF and the utility should submit the matter to arbitration at the time of termination with the burden on the utility to show its actual damages. Other parties seem to suggest that any of the proposed termination "penalties" are arbitrary and should be rejected.

(6) Discussion

Our review of the utilities' termination provisions is not one to determine the utilities' compliance with OIR 2, since our decisions gave no specific directions in this regard, but rather the reasonableness of the utilities' proposals. In making this evaluation, we must initially decide what termination provisions should accomplish and whether those provisions should be standardized between the utilities.

On the first question, we agree with the staff that termination provisions should encourage QFs to fulfill their contractual obligations, provide reasonable certainty of the consequences of termination, and make the utility and its ratepayers whole. With respect to contract standardization, we conclude that there is no reason for the termination provisions to vary greatly between utilities with respect to the basic requirements of such provisions. The type of damages caused to a utility by a QF's termination would essentially be the same for ~~energy~~ every utilit~~ies~~y with the actual amount of those damages differing depending on each utility's capacity prices. Without such ~~constancy~~ consistency between termination provisions, a QF could be too greatly advantaged or disadvantaged, for no apparent reason, solely on the basis of its location.

Each of the utilities ~~have~~ has chosen to include liquidated damage clauses in ~~their~~ its offer~~s~~. Such clauses are not "penalties" as argued by some QFs, but are in fact an accepted method of making the party who is not terminating whole. The benefits of a liquidated damage clause include the limitation of damages to the amounts or formula prescribed in the clause and the parties' advance knowledge of how the damages for termination will be calculated. These characteristics of liquidated damage clauses make them desirable and reasonable for inclusion in a utility's standard offer for firm capacity.

We must next consider, however, what elements of a utility's damages should properly be covered by such a clause. All of the utilities have prescribed some method for reimbursement of unearned capacity payments. We believe that such reimbursement is appropriate for the reasons recited by PG&E. In particular, the utility is not required to pay more than its avoided costs for the purchase of energy from a QF. Any payment over this amount arising from price levelization should therefore be refunded to the utility.

The methods chosen by the utilities to calculate this reimbursement appear to result in essentially the same measure of repayment and are reasonable. The only element of the repayment which requires further consideration is the interest to be charged, if any, on the amount refunded. We conclude that to reflect the time value of money, an interest charge is required and further that such a charge should be determined uniformly by the utilities by reference to one source.

While various suggestions have been made, i.e. simple or prime interest rates, we believe that an appropriate standard is that used in relation to the utilities' balancing accounts. Specifically, we have adopted the commercial paper rate as the charge on funds held in the Energy Cost Adjustment Clause (ECAC) balancing account. In doing so we have made these observations: (1) a variable monthly interest rate, as opposed to a fixed rate, reflects actual market conditions; (2) compounding of interest best reflects the actual burden on the utility and ratepayer; (3) commercial paper is the lowest cost form of short-term borrowing available to the utilities for financing under-collections; (4) the Federal Reserve Statistical Release, G. 13, is a reliable indicator of the interest rate applicable to commercial paper, prime three months; and (5) recognition should be given of the higher cost of financing for SDG&E. (D.91296, 3 Cal PUC 2d 197 (1980).) In D.91296, based on these findings, PG&E, Edison, and SDG&E were ordered to conform the interest rates applicable to their various accounts to "the published Federal Reserve Board three months Prime Commercial Paper rate (plus 50 basis points for San Diego Gas & Electric Company)". (3 Cal PUC 2d at 202.) We conclude for reasons similar to those recited above that this defined commercial paper rate is a reasonable rate to be applied to the repayments required of a QF ~~who~~ which terminates its contract.

While we have found reasonable the utilities' provisions for reimbursement in the event of termination, we must also consider whether it is reasonable and necessary for liquidated damages associated with a utility's replacement costs to be specified as well. Further, we must answer whether the amount of the utility's damages should be reduced or eliminated by a QF giving advance notice of its termination. We conclude that the standard offers should include both such provisions.

As stated by SDG&E, with notice depending on the amount of capacity being reduced or terminated, a utility would have sufficient time to replace that capacity, either through purchase or construction, prior to the capacity actually being lost. Although Edison argues that the utility will incur replacement costs at any time there is a termination, this position fails to recognize the utility's ability to mitigate these costs by being notified in advance of the termination.

We therefore adopt the distinction between QFs which terminate with prescribed notice and those which do not. The evidence in this case regarding appropriate notice periods depending on the amount of capacity being terminated is limited to the specific proposals made by PG&E and SDG&E. We believe that such a provision, however, can vary between utilities based on their best estimates of the time it will take them, given their individual operations and planning, to replace the lost capacity. We have no reason to question either SDG&E's or PG&E's notice periods. Edison, however, will be directed to prescribe a table similar to that used by those utilities prescribing varying lengths of notice for the amount of capacity being terminated up to the maximum capacity any QF could have. Thus, upon termination, QFs giving the prescribed notice will only be required to reimburse the utility for overpayments.

For QFs who fail to give the requisite notice, we find reasonable for all utilities PG&E's approach to calculating the damages to be added to the refund of overpayments. PG&E's formula is less complex than that used by SDG&E, provides certainty with respect to the QF's financial obligations upon termination, and recognizes the value of notice which is actually given.

PG&E's proposal, however, requires one modification. Under the terms of PG&E's offer, a QF is required to pay only one year's worth of the utility's replacement costs. If the notice periods adopted by PG&E and the other utilities are a true reflection of the time which the utility needs to replace the lost capacity, the adopted damage formula should reflect that needed time. Thus, a QF which was required under the contract to give five years' notice of termination, but only gave two, should be obligated to pay three years' worth of the utility's replacement costs. For those QFs with notice periods under one year, as ~~are~~ provided in PG&E's standard offer, the damage formula should also be adjusted to reflect a payment of replacement costs which corresponds to the required notice period.

These modifications are necessary in part to respond to the reasonable requirement that the liquidated damage clause, as much as possible, reflects the utility's actual damages.

For this same reason, we reject staff's suggestion that the utilities' references to future capacity prices be deleted from their offers and that the ~~penalty~~ additional payment for failure to give adequate notice be based ~~instead~~ on 50% of the levelization overpayment. ~~penalty~~. While it would certainly be beneficial for a QF to calculate its termination payment at the time of signing the contract, such a circumstance is not one of the principles of termination guiding our decision and, in fact, may conflict with the accepted standard of damages of making the nonbreaching party whole. The replacement costs which the utility will incur will, in fact, depend on the cost of new capacity at the time of termination, not at the time of contract signing.

We also find Edison's requirement that a QF provide evidence of its ability to make potential termination payments burdensome and unreasonable. While Edison is no doubt properly motivated to protect its ratepayers, such a provision is not a usual prerequisite in contracts and does not further the basis for termination provisions. The operating and performance standards of each of the utility's firm capacity standard offers, as modified here, are sufficient to ensure that the QFs signing these offers will be capable and dependable. It is ~~the development of~~ this very group of energy producers which should be encouraged to sign offers and should not be discouraged by unreasonable contract requirements.

~~With respect to~~ Staff's suggestions regarding the application of PG&E's probationary period to capacity reductions, ~~we believe that this issue~~ has been covered in the previous section. Whether this period also should be applied to failures to maintain certain governmental authorizations is not clear. We unfortunately have no evidence to suggest how long it would take to cure such defects. Because other parties had different views and suggestions regarding provisions requiring the maintenance of governmental authorizations, we will consider this entire issue in the next decision on these applications.

Because of the various formulas and notice periods to be used in the utilities' termination provisions, the staff's recommendation that the utilities give clear examples in their offers of the operation of their provisions has merit. Each utility's standard offer for firm capacity should, therefore, include such examples.

Finally, we note that a reduction, as opposed to a total termination, of capacity under a firm capacity contract is more similar to a modification of the contract than to a complete breach. Such a capacity reduction should not result in a complete termination of the agreement. The principles adopted above, however, are properly applied to such a reduction. The utilities' termination provisions should, therefore, clearly reflect their application to the amount of capacity being reduced, in the manner adopted by PG&E and SDG&E.

b. Simultaneous Purchase and Sale

In D.82-01-103 we specifically addressed a QF's ability to convert from a simultaneous purchase and sale of energy to a sale of surplus only. The concept of simultaneous purchase and sale is a regulatory convention which allows a QF simultaneously to sell its own generation to the utility while purchasing its requirements from the utility. A QF would elect this option for economic reasons (i.e., the retail rate being less than the avoided cost).

While we approved such conversions, we also imposed certain restrictions to ensure that the utility and its ratepayers are compensated for any lost capacity costs. In particular, we agreed with PG&E that such a conversion would be conditioned on reasonable notice and full compensation. Such conversions were limited to once per year and were subject to the following:

> "...The QF that receives capacity payments under simultaneous purchase and sale through a long-term contract and converts to sell surplus will face termination provisions." (D.82-01-103, at p. 36.)

Many of the QFs participating in this proceeding took issue with both the limitation on the frequency of such conversions and the application of termination provisions to that change. Given our directives in D.82-01-103, however, these issues would more properly have been raised in a petition for rehearing of that order. We further believe that the decision, which is now final, properly addressed these issues. We find no basis for changing our previous conclusions.

We note also that the termination provisions which we have adopted in this order apply to both reductions in capacity ~~and~~ as well as complete termination of the agreement. PG&E's contract language governing the conversion from simultaneous purchase and sale to a surplus-only sale properly directs that a QF which undertakes such a conversion will be subject to termination provisions only for the amount by which the contract capacity is reduced. Specifically, the language of PG&E's contract of Section A-3.2 of Appendix A reads: "If the energy sale conversion results in a capacity sale reduction, the provisions in Appendix D (PG&E's termination provisions) shall apply." We believe that this approach complies with OIR 2 and should be used by all three utilities.

c. Notice of Termination in As-Available Contracts

Edison's standard offer for as-available capacity states in Section 5:

> "This agreement shall become effective on the date of execution by the parties and shall remain in effect until terminated by Seller upon one year prior written notification given to Edison, which notification shall not be given prior to the date the generating facility is operating and delivering energy to the point of interconnection."

Edison justifies the inclusion of this notice requirement as necessary for determining the number of as-available producers which, in the aggregate, will be ready and willing to sell energy and capacity in any particular year.

We reject Edison's argument. The inclusion of such a provision in an as-available contract is unreasonable and in conflict with D.82-01-103. In that order we specifically stated that termination provisions were not appropriate for offers to purchase as-available power. The staff in its brief correctly summarizes the reasoning behind this conclusion:

> "...Unlike firm capacity QFs, a QF with an as-available contract is under no obligation to supply power to the utility, and it is paid only for the power it delivers. The QF's incentive to produce power is its economic self-interest, not contractual penalties. Since a QF who terminates its contract is indistinguishable from a QF who chooses not to produce while maintaining its contract, staff sees little purpose in Edison's notice requirement." (Staff concurrent brief, at page 62.)

We will, therefore, direct Edison to delete ~~its~~ the notice of termination requirement from its standard offer for as-available capacity.

B. Capacity Prices

D.82-01-103 provides that QFs which sell electricity to the utility shall be eligible for payments based on the costs that the utility system avoids through purchases of such QF power. For the standard offers which are the subject of these compliance hearings, the costs that utilities avoid by purchasing increments of QF power are defined on the basis of a short run incremental or marginal cost methodology. Short run marginal costs on the utility system consist of two components: shortage costs and operating costs. QFs receive energy payments for reducing utility marginal operating costs. QF's receive capacity payments for reducing marginal shortage costs on the utility system. This section evaluates the capacity prices which PGandE, Edison, and SDG&E propose to pay QFs pursuant to D.82-01-103.

~~We have determined~~ In D.82-01-103 we determined that QFs should receive capacity payments for both as-available and firm sales to the utility. This conclusion reflects the fact that QF output on either basis will increase the ~~supply~~ amount of electricity available to the utility, increase reserve margins, and make the possibility of outages less likely. Stated another way, QF power will lead to avoided shortage costs and QFs should be paid accordingly.[5]

Shortage costs on the utility system at any given time can be defined as the expected cost of an outage at that time or, more precisely, the probability of an outage multiplied by the customer costs associated with an outage. As the probability of an outage increases during peak demand periods, (when reserve margins are diminished) and decreases during off-peak periods, shortage costs will be higher during ~~hourly~~ daily and seasonal peak periods and lower during off-peak periods. Shortage costs can also vary on an annual basis, as reserve margins change from one year to the next.

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[5] As noted earlier, firm and as-available QF's do receive somewhat different payments ~~schedules~~ which reflect the added value of the firm sources.

Because customer outage costs are very difficult to measure on a direct basis, we ~~have~~ adopted a proxy for shortage costs in D.82-01-103 and D.82-04-071. Specifically, we used ~~We have utilized~~ the capital costs of a utility combustion turbine peaking plant, a low-capital cost plant built to meet reliability needs alone, as a proxy for annual shortage costs. This annual shortage cost amount has been allocated disproportionately to peak and semi-peak hours within the year to reflect shortage cost variations.

There is a very clear reason for adopting the capital costs of a combustion turbine as a proxy for annual shortage costs. If utilities manage their reserve margins correctly, they will pursue capacity-related investments up to the point where the last unit of investment costs the same on an annual basis as annual expected customer outage costs or shortage costs avoided through such investment. The combustion turbine represents the marginal capacity-related investment. If marginal shortage costs exceed marginal capacity-related investment costs, ratepayers will benefit by more investment which lowers ~~reduces~~ the higher shortage costs by reducing the likelihood of outages. If marginal shortage costs are less than the costs of marginal capacity-related investments, then investments should be reduced, reserve margins allowed to shrink, and shortage costs to increase. Overall, the utilities will seek to equate avoided shortage costs with ~~Thus, overall~~ the annual cost of the marginal capacity-related investment (represented by the combustion turbine) ~~will be equated with the shortage costs, and~~ the combustion turbine ~~will~~ is therefore a reasonable ~~be a good~~ proxy for the equilibrium shortage cost value that will exist on the utility system on average.

In the petitions for rehearing of ~~that were filed pursuant to~~ D.82-01-103 the utilities argued that annual shortage costs will sometimes differ ~~diverge~~ from the equilibrium or average combustion turbine capital cost level. Therefore, they argued, QF capacity prices should vary accordingly. In D.82-04-071 (pp. 2-3), we concluded ~~answered~~ that while the use of the combustion turbine proxy "is consistent with an incremental fuel cost that will for sometime be based on oil and gas", ~~we would agree that~~ a more precise refinement of the proxy which "varies capacity payments based on the probability of loss of load, perhaps using reserve margins, would be desirable".

D.82-04-071 clearly specified, however, ~~clearly~~ that as-available capacity payments were ~~are~~ to be based on the combustion turbine and that any refinements of the proxy were ~~are~~ to be considered only in future general rate cases. The language of D.82-04-071 was ~~is~~ less clear as to when refinements of the proxy would ~~could~~ be considered in the case of firm capacity payments. As noted earlier, pursuant to an ALJ ruling, the utilities were allowed to introduce into these compliance hearings methodologies for adjusting the combustion turbine proxy and the QF firm capacity payments that are derived from that proxy. Basically, the utilities' methodologies are aimed at reflecting year-to-year variations in reserve margin levels which lead to year-to-year variations in shortage costs.

The two issues before us now are (1) whether or not PGandE, Edison, and SDG&E ~~are using~~ used accurate combustion turbine costs in calculating their as-available and firm QF capacity prices and (2) whether ~~that~~, in the case of firm capacity prices, the utilities' proposed adjustments of the combustion turbine proxy should be adopted.

A. The Cost of the Combustion Turbine

Firm and as-available capacity prices in all of the utilities' filings are based directly or indirectly on the capital costs of a combustion turbine. The accuracy of these plant cost estimates is thus an important issue in this proceeding. The threshold question here is whether or not the combustion turbine costs should be uniform between ~~across the~~ utilities, based on a "generic" combustion turbine plant, or whether the costs should be more utility-specific.

We agree with the utilities that combustion turbine costs can vary ~~across~~ between utilities due to different financing costs, environmental requirements, and locational factors. The costs of meeting a shortage through construction of peaking capacity will legitimately vary from one utility to the next ~~on these grounds.~~ because of these factors. However, it is much less clear why other factors that are not utility-specific in nature, such as forecasts of general economic indices, should vary in the combustion turbine costs estimates adopted ~~that we adopt~~ for PG&E, SDG&E and Edison ~~today~~. We do not agree with the utilities that these broader indices need to vary by utility to reflect differing corporate assumptions. If corporate assumptions about such items as inflation and oil prices had to be ~~adhered to~~ followed, staff and other parties could not challenge such assumptions as they normally do in other proceedings such as the utilities' general rate cases. We will allow for utility-specific cost variation where it is shown to be warranted, but ~~we~~ will strive for ~~consistency~~ uniformity in the case of assumptions that are not clearly utility-specific in nature.

The estimation of combustion turbine capital costs and the application of such costs to capacity prices in contracts of different lengths requires estimates of numerous factors. These include combustion turbine construction costs, fixed charge rates, plant economic life and book life, fixed operations and maintenance costs (O&M), fixed administrative and general costs (A&G), fuel inventory costs, escalation rates, and discount rates. We will consider these factors in the context of each of the utilities' capacity price filings.

a. Edison

Staff and IEP argue that Edison's basic combustion turbine capital cost, \$415/kW, is too low, and argue instead for \$450/kW based on Edison's CFM-IV filing and staff's "generic" combustion turbine estimate. Edison argues that the $415/kW number is an estimate based on a January 1, 1982 on-line date and that ~~their~~ its CFM-IV estimate was a "rounded" version of a combustion turbine with a June 1, 1982 on-line date. The latter is a higher figure because of inflation. We find that Edison's estimate is reasonably close to staff's "generic" turbine estimate and that it is consistent with the combustion turbine proxy that we adopted for rate design purposes ~~in D.~~ Edison's ~~the~~ test year 1983 ~~Edison~~ general rate case. Also, the January 1 number is more consistent with the average year rate base fixed charge rate methodology that is used by Edison and staff. Therefore, we will adopt $415/kW for 1982 combustion turbine capital costs for Edison.

To spread the combustion turbine capital costs to capacity prices ~~across~~ over the years of various QF contracts~~lengths~~, including the single year as-available contract, fixed charge rates and constant dollar factors are ~~utilized~~ used. These factors ~~in turn~~ depend in part on the economic life that is assumed for the combustion turbine. Edison argues that a 30-year economic life should be used. This period, in Edison's ~~in their~~ view, is a realistic estimate of the useful life of such a plant. Staff and IEP counter that Edison uses a 23-year assumption to depreciate its own plant and that a 30-year assumption ~~would be~~ is inconsistent with this approach and ~~would~~ artificially disadvantages QFs.

We have previously considered this issue in D.93887 (p. 275), ~~wherein~~ in which we decided that PGandE should use a 24-year combustion turbine useful life assumption consistent with its own depreciation schedules. Edison's assumption is inconsistent with D.93887 and with PGandE and SDG&E filings in this proceeding. We will adopt the 23-year economic life for Edison's capacity prices. ~~If Edison seeks to change~~ Any change by Edison in its own depreciation schedules to more closely reflect its estimate of useful plant life, made in this proceeding ~~this~~ should be considered in ~~their~~ Edison's general rate case.

~~Two other factors that~~ Escalation and discount rates also affect the combustion turbine-based capacity price stream for different contract lengths and different startup dates. ~~are the escalation and discount rates that are used.~~ The 15% discount rate used by staff and Edison, based on an estimate of ~~the company's~~ Edison's incremental cost of capital, is reasonable. The escalation rates for capacity prices, fixed O&M, and fuel prices used by staff are reasonable. Edison argues that these latter staff assumptions are at odds with its corporate assumptions used for planning purposes in general. We believe that these are factors ~~that~~ which are not utility-specific in nature. The use of the staff assumptions here is consistent with adoption of the same assumptions for PGandE's and SDG&E's combustion turbine cost estimates, discussed below.

The staff fuel price assumption is only important for combustion turbine cost estimation if the combustion turbine fuel inventory cost escalates over the life of the unit. Edison contends that this fuel inventory cost should not be escalated. In effect, Edison assumes that gas will always be available for use in the turbine over the life of the unit and that the liquid fuel inventory will never be used. Staff and IEP argue that the inventory costs should be escalated, using their oil prices price escalation assumptions. Staff argues that gas may not always be available and that even if it is, it may not be the cheaper fuel option. Therefore, the inventory will be used and replaced over time. The staff escalation rate assumption implicitly assumes that the inventory will be replaced annually.

We conclude that the most reasonable assumption ~~is~~ lies ~~somewhere in~~ between the staff and Edison positions. It is unlikely that the inventory will be replaced annually and such an assumption may overstate avoided fuel inventory costs, particularly since Edison normally uses first-in-first-out (FIFO) fuel inventory accounting. The assumption that the inventory will never be turned over, however, is equally unrealistic. We will adopt an escalated fuel inventory using 50% of the staff's annual escalation rates, reflecting partial annual use of the inventory over time.

Another item of contention between Edison, staff, and IEP, is the proper amount of fixed A&G costs that should be capitalized as a part of the combustion turbine cost. Edison uses 1% of the capital costs of the plant as a measure of levelized annual A&G costs over the life of the plant. Staff uses 1% of the capital costs of the plant as a measure of the first year A&G costs and escalates this figure over the life of the plant. ~~This~~ The result is equivalent to a 1.6% levelized A&G figure. Staff argues that Edison used the 1% escalating figure in its most recent general rate case. IEP argues that a 2% levelized figure should be used, citing a 1982 staff study that showed Edison's A&G costs to be 2% or higher ~~as a~~ percentage of fixed plant. Edison in this proceeding repudiated its rate case marginal cost A&G assumption and questioned the applicability of the staff calculations in Exhibit 16 ~~that~~ upon which IEP relied ~~on~~ in making its argument.

It is apparent from the record here that the relationship between A&G costs and fixed plant additions is not fully understood. We agree with Edison, however, that the degree to which A&G costs are actually avoided by QF purchases is problematic. Under these circumstances, a conservative approach is appropriate in preserving the A&G measure. We will therefore ~~so that conservatism is in order on the A&G measure. We will~~ adopt Edison's 1% levelized figure for A&G.

Staff, IEP, and Edison also disagree on the appropriateness of Edison's "differential fuel credit". Edison includes in its combustion turbine capital costs a measure of the increased fuel costs that occur, above the system marginal operating cost, when the combustion turbine is actually operated. We agree with IEP and staff that Edison should account for this increased marginal operating cost not in the combustion turbine capital cost, but ~~rather~~ in its estimate of the system marginal operating cost. In other words, the costs of operating the combustion turbine should be reflected in QF energy prices, not capacity prices.

Finally, we note that Edison in its brief argues that the staff's fixed charge rate in Exhibit 71 differs ~~diverges~~ from Edison's rate for reasons other than the varying ~~differing~~ fixed charge rate assumptions of the two parties. This circumstance appears to be purely a computational problem. We will direct Edison in this order to file capacity prices that are based on combustion turbine costs that reflect our preceding ~~foregoing~~ conclusions about costs. ~~If any computational problem persists at the time of the filing it should be resolved by a decision of the Executive Director.~~

b. SDG&E

SDG&E's capacity price filing utilizes a combustion turbine capital cost of \$400/kw. Staff argues, as it did in the case of Edison, that \$450/kw is a more appropriate figure. Staff found the SDG&E estimate to be too low because of inadequate allowance for cost overruns, pollution control requirements, new site costs and other factors. SDGandE counters that its allowance for cost overruns is consistent with historical experience, that it has included requisite pollution control costs, and that it is unrealistic to include new site costs given that SDG&E would be much more likely to add combustion turbines at existing sites.

IEP argues that the combustion turbine cost used in SDG&E's test year 1982 rate case (A. 59788), $618/kw, should be used for capacity prices here. SDG&E ~~argues~~ states in Exhibit 37, that the rate case figure reflects a 500MW combustion turbine development at a new site with an anticipated baseload mode of operation. The OIR-2 filing reflects the avoided costs of a 50MW peaking unit at an existing site.

We will adopt SDG&E's capital cost estimate of $400/kw. It is reasonably close to Staff's "generic combustion turbine" estimate and the reasons for its being ~~why it is~~ lower, such as the use of existing plant sites, are justifiable on utility-specific grounds. We agree with SDG&E that their rate case cost estimate is based on a plant type that does not sufficiently reflect the marginal peaking capacity investment that we have chosen for the shortage cost proxy.

Staff and SDG&E differ on the proper escalation rates to be used for capacity costs, fixed O&M, and fuel prices. Consistent with our discussion of the Edison combustion turbine costs, we will adopt the staff estimates. We do, however, agree with SDG&E that more recent, lower inflation rates should also lead to a lower estimate of the incremental cost of capital that is ~~utilized~~ used in the fixed charge rate. We will revise the staff figure of 16.5% down to 15.5%. This approach is consistent with the estimate used for Edison while also taking into account the different credit ratings of the two utilities.

The record is silent on whether SDG&E included an A&G cost in its combustion turbine cost estimate. We agree with ~~S~~staff, which argues in its brief, that an A&G component should be included. SDG&E A&G costs should be commensurate with those adopted for Edison.

Staff and SDG&E are in agreement on fuel inventory costs, fixed O&M costs, and the economic life of the plant. We will adopt these figures.

For the purposes of calculating capacity prices, SDGandE will be directed to utilize combustion turbine costs which conform to the foregoing conclusions.

~~4~~c. PGandE

PGandE filed capacity prices that were based on combustion turbine capital costs of $770/kw. This estimate ~~is~~ was taken from ~~the company~~ PG&E's most recent general rate case. (D. 93887). Staff argues that, unless the Commission ~~utilizes~~ uses a generic combustion turbine cost, it would be simpler to use the rate case number ~~that PGandE has~~ used by PG&E. IEP concurs that the rate case estimate should be used, but offers several suggestions about various combustion turbine costing assumptions should the issue be considered anew.

We do consider it to be important to examine the combustion turbine cost assumptions in this decision rather than merely accepting estimates from previous rate cases. We indicated in D. 82-01-103 and D. 82-04-071 that the combustion turbine was a reasonable ~~surrogate~~ proxy for shortage costs. The purpose of these compliance hearings was to examine the adequacy of the method by which the utilities translated this concept into capacity prices.

From the perspective of the record in this proceeding, in which three utility filings ~~are~~ were considered together, PGandE's capital cost estimate from its rate case appears to

~~diverge~~ vary from that of the other utilities by an unreasonable amount. This ~~divergence~~ variance is wider than one could reasonably expect from utility-specific factors alone. Therefore, we will not adopt this estimate and will instead adopt the staff's generic combustion turbine capital cost of $450/kW for PGandE. This estimate is closer to our adopted capital costs for Edison and SDG&E.

We agree with IEP that if one combustion turbine cost estimate from PGandE's rate case is examined and updated here, other assumptions should be examined as well. We will therefore not adopt staff's use of the rate case escalation and discount rates. Instead, we will adopt for PGandE the more recent estimates for capacity price, O&M, and fuel price escalation that staff has recommended for ~~utilities in the case of~~ Edison and SDG&E. ~~Also,~~ We will also adopt ~~IEP's 15.~~% 15.0% incremental cost of capital, which is consistent with our adopted discount rate assumptions for Edison and SDG&E.

IEP notes that the rate case combustion turbine estimate did not include a fuel inventory cost. To ~~assure greater~~ ensure consistency, ~~here~~ we will direct PGandE to include a fuel inventory cost component equivalent to that adopted for Edison.

We find that the assumptions ~~that~~ used by PGandE ~~used~~ in its rate case estimate as to the economic life of the turbine, fixed O&M costs, and fixed A&G costs are reasonable.

no new ¶ We will direct PGandE to derive capacity prices based on combustion turbine cost assumptions adopted in the foregoing discussion.

2. Adjustments in the Combustion Turbine Proxy for Firm Capacity Payments

As noted earlier, the utilities proposed in these compliance hearings that their firm capacity prices be based on methodologies that adjust the combustion turbine shortage cost proxy for year-to-year variations in reserve margins and reliability.

no ¶ Staff supported these methologies in concept, but criticized several specific elements of the methods. Also, Staff argued that because of the uncertainty over the accuracy of the methods and the related assumptions, a "floor" on downward adjustments of the combustion turbine proxy ~~carried out pursuant to the new methods~~ should be adopted. The floor capacity price in any contract year would be 50% of the annual combustion turbine cost.

IEP, Occidental, The State Energy Task Force and other QF ~~parties~~ opposed the utilities' methodologies, arguing that they were given inadequate opportunity to examine the ~~utilities'~~ methods in the hearings. ~~and that~~ Further, the limited examination that did take place showed that the utilities' methodologies were seriously flawed.

We will consider all of the parties' positions ~~these arguments~~ in the context of each utilities' proposed shortage cost methodology.

~~D.~~ PG&E

PG&E proposes that the combustion turbine proxy be set as the maximum annual shortage cost and that this value should be adjusted downward in years in which reserve margins are forecasted to be above target levels. PG&E proposes that this downward adjustment be based on an Energy Reliability Index (ERI). The ERI is derived from PGandE's Generation Reliability and System Simulation Model (GRASS). The ERI is a probablistic measure of the expected size and frequency of reduced electric energy deliveries which ~~that~~ are forecasted to result from generation capacity limitations in future years. An ERI number is derived for each future year in which firm QF capacity prices must be calculated. In years in which PGandE's reserve margins are expected to be smaller than or equal to target levels (with loss of load probabilities greater than or equal to the target one day in ten years), the ERI adjustment factor is set at 1.0 and the QF capacity price is set at the full combustion turbine cost level. In years ~~where~~ in which reserve margins are atypically large the ERI adjustment factor is calculated as the ratio of the ERI in the large reserve margin year in question to the ERI in a base year when reserve margins are at their target levels. This ratio, a number less than one, is multiplied by the full combustion turbine cost to ~~get~~ produce a QF capacity price for that year which is less than the full combustion turbine proxy.

We believe that PG~~and~~&E has presented an innovative methodology for measuring shortage costs. However, we agree with other parties in the proceeding that the method is underdeveloped and suffers from several important flaws in both concept and actual application.

~~The most~~ One important conceptual flaw is that the ERI method is biased because it allows for downward adjustments in the shortage cost proxy when reserve margins are above target levels, but does not allow for upward adjustments in years in which reserve margins are below target levels. We agree with Occidental and IEP that such upward adjustments should be a part of any precise shortage cost methodology. Clearly, as noted earlier, the combustion turbine is a proxy for the equilibrium or average shortage cost value. Actual shortage costs will vary above and below the equilibrium value, due to the "lumpiness" of powerplant capacity additions. This circumstance is especially true in the case of ~~near term~~ shortage costs for the near term, a time frame in which unexpected demand increases cannot be met with new plant additions because of the lead time associated with new plant construction. ~~Thus, the PGandE method is biased because it only allows for downward adjustments of the shortage cost proxy.~~ In the calculation of longer term shortage costs, an upper limit equal to the cost of a combustion turbine proxy may be appropriate, depending on the precision our forecasts.

A second conceptual problem with the PG~~and~~&E method is that it treats many of the uncertain factors that affect future reserve margins in a deterministic fashion. It is a basic tenet of supply planning that the greater the uncertainty about future demand levels, plant start-up dates, and plant maintenance requirements, the greater the reserve margin "insurance premium" that is needed. for PG&E's assumption not to reflect ~~To assume away~~ the uncertainty about these factors is to understate reserve needs. As PG&E has stated in its CFM-IV filing:

> "The explicit inclusion of uncertainty will always require a larger reserve capacity to maintain the same level of reliability, given the assumed certain outcome falls in the middle of the range of possible outcomes...PGandE's (supply) planning reflects this consideration." (Ex. 58).

We agree with Occidental that, if uncertainty leads PGandE to increase its estimates of shortage possibilities and reserve needs for its own supply planning purposes, PG&E to be consistent, ~~the company~~ should also take this uncertainty into considera- tion in calculating capacity payments to QFs. In this approach ~~Without this,~~ "is not used," QF capacity value will be understated.

Another shortcoming related to the development of the PGandE methodology ~~which was made apparent during the hearings was that PGandE has not~~ is PG&E's failure to perform ~~performed~~ a sensitivity analysis on the ERI model to investigate whether or not the ERI results would be drastically altered by small changes in input assumptions. PG&E has argued that the ERI results are not likely to be sensitive. Staff points out in its brief, however, that the evidence indicates otherwise. The relatively small adjustment PG&E made during the proceeding in its input assumption about load management achievements led to a relatively large change in the ERI result. In general, the lack of sensitivity analysis casts doubt on the validity of the ERI results.

Apart from these weaknesses in the PG&E shortage cost methodology itself, numerous questions arose during the hearings about the application of the methodology to the standard offers. ~~in this particular instance.~~ It appears that PG~~and~~&E ~~utilized~~ used several erroneous input assumptions when it calculated ERI adjustment factors and derived its proposed QF capacity prices. Start-up dates for the Diablo Canyon nuclear plant and the Helms pumped storage facility were assumed to be January 1, 1982 and August 1, 1983 respectively, both of which are incorrect. Future forced outage rates on plants such as Rancho Seco and Contra Costa 1 were assumed to be much less than ~~that which has been~~ the outage rates experienced historically. The derating of the Pittsburgh 7 plant was not taken into account. Demand forecasts were based on older, higher oil price assumptions and therefore were probably understated. Demand may have also been understated, ~~and~~ in turn understating shortage costs, ~~therefore understated~~ because ~~in~~ the forecast load management goals were assumed to have been fully achieved.(6)

Forecasts of future reserve margin levels are obviously extremely difficult undertakings which involve many assumptions about future loads and resources. PG&E's assumptions were not adequately substantiated in the hearings. ~~Numerous~~ Many of the assumptions appear to have the effect of understating future shortage costs and ~~resulting~~ QF capacity payments.

PG&E offered two revisions of its assumptions which lessen this problem to a certain degree. First, the extent of its assumed load management achievement was ~~lessened~~ reduced. Second~~ly~~, ~~it~~ PG&E offered to make a retroactive upward revision in QF capacity payments if the Helms and Diablo start-up dates

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(6) We note in passing that while load management goals should not be included, we do not agree with Staff and IEP that load management should not be included at all. Rather, we concur with Edison's argument in its brief that load management, utility resources, and QF power must be considered, to the extent feasible, simultaneously, not sequentially, in the estimation of future shortage costs. However, load management assumptions must be conservative, especially when estimating the impact of voluntary programs.

~~are~~ were not realized.

We consider the retroactive payment revision undesirable because it does not signal QF's prospectively about the value of their future performance. More importantly, we do not consider these two proposed revisions of ~~the~~ PGandE's capacity input assumptions ~~used in the calculation of QF's capacity payments to be~~ are sufficient to alter our conclusion that the EPI input assumptions ~~are such that~~ result in understating shortage values and QF capacity payments. ~~are understated~~

Because of the methodological flaws and questions surrounding PG&E's input assumptions we will not adopt PG~~and~~&E's shortage cost methodology. While ~~We~~ we will not preclude new proposals in future hearings ~~which are~~ aimed at refining the shortage cost proxy, ~~but~~ at this time we conclude that ~~the~~ PGandE's firm capacity payments, like its as-available payments, should be based on the basic combustion turbine proxy, using the combustion turbine cost assumptions adopted ~~earlier~~ previously in this decision.

8 b. SDG&E

SDG~~and~~&E proposed a shortage cost methodology which is similar ~~to that of~~ PG~~and~~&E's. In SDG&E's methodology, an annual "probability of need" is calculated using ~~the company's~~ SDG&E's production simulation model, PROMOD. The probability of needing capacity varies from year to year as reserve margins vary. The maximum value of the probability of need is 1.0, and in such years QF capacity prices are set equal to the full combustion turbine. In years ~~where~~ when reserve margins are above target levels, the probability of need is less than one and the full combustion turbine capacity price is adjusted downward accordingly.

In its brief SDG&E claims that certain criticisms of ~~that were levelled against the~~ PG~~and~~&E's method do not apply to SDG~~and~~&E's ~~case~~ methodology. In particular, SDG&E claims that it ~~to~~ uses more realistic input assumptions in its reserve margin forecast. For example, forced outage rates on existing units are assumed in the PROMOD forecast to be similar to ~~that which has been~~ those experienced historically ~~on those~~ by the plants. Forced outage rates on new units are assumed to be higher than ~~that~~ those experienced by other utilities with plants of the same type, to provide "a cushion against error". Finally, SDG&E ~~claims~~ asserts that it has taken into account the impact of more recent, lower oil price forecasts in its demand forecast and reserve margin forecast.

~~As we evaluate the~~ In evaluating SDG&E's shortage cost method, it is immediately apparent that ~~it~~ the method includes certain flaws similar to those ~~that were~~ enumerated for ~~found in the~~ PG&E ~~case~~. For example, a basic methodological shortcoming is that the shortage cost proxy can only be adjusted downward and can never exceed the equilibrium or average combustion turbine level. ~~Also~~ Further, an increasing shortage cost trend ~~across~~ through the years can, under ~~the~~ SDG&E's method, never be followed by any downward trend, even if this situation ~~were to~~ more accurately reflected reserve margin changes. Finally, ~~in the area of~~ with respect to input assumptions, it appears that uncertainty about new plant on-line dates was not taken into consideration and that, ~~allowed for and,~~ for example, an unrealistic assumption was made about SONGS 2 being fully available by the beginning of 1982. ~~was made for.~~

It is difficult to evaluate ~~the~~ the extent to which SDG&E's method suffers from flaws in data and methodology because ~~the~~ SDG&E's ~~company's~~ shortage cost method was not sufficiently examined ~~in~~ during the hearings ~~the record~~. SDG&E changed its methodology late in the proceeding after staff had already undertaken its ~~compliance~~ evaluation of SDG&E's capacity prices. SDG&E did not adequately substantiate its new method and the input assumptions that it used. The ALJ ordered ~~the company~~ SDG&E on October 15, 1982 to provide data on its input assumptions and its methodology in keeping with our decision in OII-26 which set up certain requirements ~~for the submittal of~~ to substantiate evidence in cases involving computer simulations. Such information was to be provided to staff and ~~to~~ the State Energy Task Force during the briefing schedule. However, both staff and the State Energy Task Force indicated in their briefs that they had still not received the data at the time ~~the~~ briefs were completed in mid-November.

Because SDG&E's ~~the~~ methodology appears to have certain flaws similar to those found in ~~the~~ PG&E's approach ~~case~~ and because the SDG&E ~~company~~ did not adequately substantiate its proposed refinement of our adopted shortage cost proxy, we will not adopt SDG&E's ~~the company's~~ proposal. Instead, we find that the basic combustion turbine cost is an adequate proxy for shortage costs and should be used for SDG&E's firm capacity payments. This finding is consistent with D.82-01-103, with ~~the~~ SDG&E's as-available capacity price, and with our previous conclusion relating to ~~in~~ PG&E's firm capacity price, ~~noted above~~. As we noted in the case of PG&E's method, our adoption of the basic combustion turbine shortage cost proxy for firm capacity prices does not preclude the further consideration of more precise shortage cost methodologies in future hearings.

~~3~~ c. Edison

Edison's proposed refinement of the combustion turbine proxy represents a different methodology than that proposed by PG&E and SDG&E. Rather than adjusting the combustion turbine proxy to reflect the results of computer simulations of likely future reserve margins, Edison proposes that QF capacity prices should ~~be set~~ equal ~~to~~ the price of wholesale market capacity contracts between 1982 and 1985 and ~~set equal to the~~ full combustion turbine costs thereafter.[*] The wholesale market price

[*] The combustion turbine costs are based on the value of deferring a combustion turbine over the length of the contract. This is a slightly different approach for deriving the levelized price for different contract periods than that used by PGandE. PGandE applies a real economic carrying charge to an annually inflating turbine cost and levelizes the resulting escalating payment stream. Both approaches should lead to the same result given the same assumptions and either is acceptable.

that Edison primarily relies on for 1982-1985 QF capacity prices is the emergency capacity price in the California Power Pool Agreement. Secondarily, Edison states that this price is also supported by the Edison - California Department of Water Resources Contract, and the Principles of Interconnected Operations for the Navajo and Four Corners Power Projects. Edison contends that its \$24/kW/yr, 1982-1985 capacity price for QFs is quite generous. ~~The company~~ Edison points out that it would only pay such a price for emergency purchases under its wholesale contracts if it were to take emergency power for the entire twelve months of the year. In Edison's view, ~~this~~ such a circumstance is very unlikely.

The State Energy Task Force contends that the wholesale contracts that Edison relies upon for its 1982-1985 QF capacity price are complex energy and capacity exchange agreements that involve shared services. Because it is a part of such a package, the State Energy Task Force claims, the emergency power price cannot ~~be looked at in~~ isolat~~ion~~ed and used by Edison in developing its shortage cost.

~~There is merit in~~ The State Energy Task Force's claim has merit. It is quite possible, for example, that within these reciprocal exchange agreements, emergency power services are mutually underpriced by the parties to the agreement. If this is so, taking the California Power Pool agreement as an example, then a QF which allows Edison to avoid a capacity purchase from PG&E would be avoiding Edison's capacity purchase costs and ~~avoiding~~ PG&E costs ~~that~~ which are not covered in the purchase price. The fact that the price of emergency power in the California Power Pool has not changed since 1964 despite inflation and narrower reserve margins makes this possibility quite plausible.

Edison argues that ~~we must~~ it is necessary to focus on the costs that it actually avoids when it does not make a wholesale contract purchase, not any additional value of the service that may not be reflected in the purchase price (or any additional cost that may be avoided by another utility elsewhere). However, if we return to the California Power Pool example, it can be seen that such a focus may not yield accurate avoided cost price signals. If PG&E and Edison were to base QF capacity prices on a mutually underpriced reciprocal exchange service, the additional costs that QFs actually avoid but ~~which~~ are not reflected in the price would never be ~~reflected in QF~~ included in QF capacity prices of either utility. This possibility weakens the validity of Edison's argument.

A second criticism of the Edison method is that the ~~existence of~~ a wholesale contract price ~~does not establish that this is a good~~ is not necessarily a reasonable proxy for the utility's marginal shortage cost. The existence of wholesale contract capacity does not indicate whether or not the contract capacity represents the marginal resource. Is the contract the most expensive increment of capacity on the system (more expensive than other capacity contracts, or load management programs, or other resources)? Is the contract the resource that would be ~~dropped or~~ avoided if QF power was accepted? Even within the narrow sphere of wholesale contracts alone, it is not clear that emergency power contracts are the type of contracts that would be displaced by constant purchases of firm QF power. Under emergency power agreements, infrequent use of the service is normally assumed by the seller. Constant firm purchases might lead to a different type of wholesale agreement and price. The latter might be a better measure of avoided cost.

A clear conclusion on the accuracy of using wholesale emergency contracts as the marginal shortage cost proxy would require more evidence about ~~the broader array of~~ all Edison's wholesale contracts, company-owned resources, and load management programs. ~~Here~~ We are hampered in our analysis, as we were in the case of SDG&E,

by ~~the company's~~ Edison's inadequate offering of data during the proceeding. For example, the State Energy Task Force submitted to Edison a data request on August 27 asking Edison for information about its capacity price methodology based on wholesale contracts. The information ~~that~~ which was sought included (1) the contracts that were used to set the $24/kW/yr 1982-1985 price, and (2) other contracts that exist, but were not used to set the QF capacity price. This ~~is exactly the type of~~ information is exactly the type required to ascertain the validity of the price calculation and the degree to which the contracts ~~that it~~ upon which that calculation is based ~~on~~ represents the marginal resource in the context of all such contracts.

Edison responded on September 21 that "much of the specific information sought is proprietary in nature". During subsequent hearing dates, however, it ~~later~~ became ~~clear, however,~~ apparent that the contracts in question are public documents filed with the Federal Energy Regulatory Commission.

In view of the doubts cast on the wholesale capacity price resulting from the reciprocal exchange arrangement ~~that it is~~ upon which it was based ~~on~~, and in view of ~~the lack of~~ the inadequate ~~adequate~~ showing indicating that the Edison contract price ~~that was chosen is~~ was an accurate reflection of ~~the~~ Edison's actual avoided shortage cost, we cannot adopt Edison's proposed methodology. As we have done in the case of ~~the~~ PG&E's and SDG&E's firm and as-available capacity price and ~~the~~ Edison's as-available capacity price, we will adopt the capital cost of the combustion turbine as a reasonable proxy for shortage costs for Edison's firm capacity prices. This conclusion does not preclude the adoption of a more precise shortage cost methodology for Edison in future hearings and does not preclude the use of wholesale capacity prices in such a methodology.

3. Conclusions on Capacity Prices

In D. 82-04-071 we concluded that: "At present the gas turbine is the best surrogate we have for capacity and it is consistent with an energy payment based on oil or gas". (Mimeo p.3). We reaffirm that conclusion today. In reaffirming this conclusion we do not posit that the combustion turbine is the most exact measure of avoided shortage costs. Given the evidence in this proceeding we essentially face a choice between imperfect measures of avoided shortage costs: (1)the utilities shortage cost measures, which have been inadequately substantiated and shown to be biased downwards in certain respects and (2)the combustion turbine proxy which is also an inexact measure and has been argued to be biased upwards. Given this imperfect choice and the uncertainty surrounding avoided shortage costs we choose the combustion turbine alternative because it gives a stronger incentive to cogenerators and small power producers. This is proper, we believe, because these power sources bring with them many important benefits to ratepayers which are difficult to quantity and not captured in the avoided cost calculation.

We will direct the utilities to file as-available and firm capacity price schedules based on the capital costs of the combustion turbine, using the combustion turbine cost assumptions adopted earlier in this decision. We also conclude that the possibility of developing a more refined shortage cost methodology which accounts for year-to-year variations in reserve margins is worth exploring further. The issue will be raised in PG&E and SDG&E's current rate cases, and in SCE's 5-year forecast energy price offer (A.82-04-46). Any revisions to capacity tables will be made prospectively, for new contracts. They will not apply to QFs which have already signed firm capacity contracts.

Energy Payments

Issues Relating to Energy Payments

A. General

D.82-01-103 stated that energy payments should be derived from a utility's shortrun operating costs, reflecting the variable cost of providing an additional unit of electricity. In calculating the energy prices, the intent of the decision was "to capture as accurately and timely as possible the current marginal energy costs incurred by the utility." (D.82-01-103, page 31.) The decision stated that the current practice was to use the previous three-month oil costs and forecasted incremental heat rates. In a later decision (D.82-11-087), the Commission made a revision and adopted prospective fuel prices in the event that gas ~~is~~ was the marginal fuel.

The parties in the case representing small power producers generally were concerned by the unpredictability of the energy prices and by their inability to verify the calculation of these numbers. Various suggestions were made to provide more certainty, including proposals to include formulas for energy in the contract, to use average annual incremental heat rates, to establish price floors, and to levelize the energy payments over time. In general, the utilities have rejected such proposals as being unworkable, overly burdensome, or unresponsive to changing conditions.

We resolve these conflicting concerns by ordering utilities to provide as much certainty as is possible in their contracts and procedures without undermining the basic concept of using the avoided energy price applicable to these standard offers. The risks QFs take relating to energy prices in these offers are not unlike the risks in a competitive spot market. For example, small power producers take the risk of changing utility fuel costs in future years as they influence the marginal energy rate. It is also consistent for incremental heat rates to fluctuate, since, in fact, ~~they~~ these rates will vary depending on future supply and demand conditions in utility operations.

SDG&E argues that the Commission's program to develop small power production "significantly reduces the QF's obligation to compete in an open and free market for the sale of QF generated power." Noting that "the QF receives a payment for its power from a regulated environment instead of an open market", ~~San Diego~~ SDG&E argues that "[t]his substantial reduction of the risk in a QF's operation, compared to an open market business operation, is an unprecedented preferential benefit provided by the State of California to unregulated businesses." (Brief, page 3.) We disagree. As described above, QF prices behave similarly to those in a competitive supply market, and the pricing does create considerable risks for QFs, not unlike those in a competitive market. In fact, our concern is that the administratively established prices in this program may create more risks for QFs than would open market prices. Unlike a free market, administrative changes can affect basic pricing methodologies, not just changes in supply and demand conditions. We agree with QFs that these risks should be mitigated whenever possible.

One major administrative risk implied by the proposed contracts is the possibility of a change in pricing policy by future Commissions. Specifically, as the contracts currently are written, some future Commission could order that a new pricing policy be adopted with prices derived at less than avoided costs. We do not believe such discretion is appropriate. While a future Commission may have the prerogative to implement pricing policy changes prospectively for new small power contracts, QFs which have already built projects should received payments derived from the pricing methodology in existence when the project was built. Otherwise, far too much price uncertainty will exist. Accordingly, we will order that utilities include a provision in all their ~~contracts~~ standard offers before us which assures QFs that they will receive payments throughout the life of the specific project ~~that are~~ derived from the utility's full short-run avoided energy costs, as approved by ~~the~~ The Commission. This requirement will ensure ~~will assure~~ that a framework is established firmly, with prices derived from a utility's full avoided costs. Since these contracts are viewed as reasonable, per se, the utility's expenses for such purchases can be assured (D.82-01-103, page 24). Such a provision does not add to utility risks, as suggested by the utilities.

The second major administrative risk for small power producers not present in a competitive market is the model used ~~itself~~ for calculating the avoided cost payment. Unlike most markets in which buyers and sellers meet at arm's length to establish prices (i.e., ~~in~~ the stock market or a commodity market), the prices established for small power producers are derived from models in possession of the utilities, as approved by this Commission. Not surprisingly, the small power producers are skeptical of this arrangement, and would at least like these models to be more explicit and understandable. We agree that this concern is ~~a~~ significant, ~~concern and we~~ therefore will require that utilities present, in detail, the assumptions behind their energy price calculations and ~~will provide the~~ that QFs have ~~with~~ an opportunity to critique the assumptions in the utility models.

To provide greater certainty and clarity, some QFs suggest that an energy price formula be written into the QF contract. We do not find such an approach to be feasible. The pricing formula is highly complex and could not suitably be incorporated. Furthermore, while QFs should have the certainty that their prices will reflect the utilities marginal variable costs, the actual model for calculating such costs may become more refined in the future. A specific formula would preclude such refinements. By clearly establishing that prices should reflect the utilities' shortrun avoided costs in the contract, and by giving QFs an opportunity to review and comment on the utilities' calculations, we believe sufficient certainty is provided as to how these payments are to be derived.

B. Determination of Energy Prices

While the policy to establish prices from the utilities' shortrun marginal operating costs is generally understood, there remains a considerable debate on how to calculate those rates. The utilities' marginal operating costs vary almost continuously, and at least at this time the metering technology does not exist to signal prices ~~at such a~~ so frequen~~cy~~tly. As a result, the average marginal cost applied for a particular time period must be used. One issue concerns ~~the length~~ how long these ~~time frames~~ periods should be, and under what conditions these prices may be adjusted from the average marginal rates. A second major issue concerns whether the methods used by utilities for calculating the marginal operating costs for a particular period are accurate.

We generally resolve these issues in two ways. First, ~~insofar as~~ to the extent possible, this decision addresses the specific concerns raised by the parties ~~concerning~~ relating to the calculation of energy prices. However, it is clear from this proceeding that not all of the potential issues relating to the calculation of energy prices were addressed. We expect that the parties will want to offer further comments and refinements in the future. Therefore, in addition to resolving many specific issues here, we will provide a procedure by which QFs and other parties can provide comments in the future. We do not provide this procedure as a forum to relitigate issues, but to allow new issues to surface. Small power producer pricing remains in an evolutionary stage, and we have no doubt that issues will continue to arise about how prices should be established within the guidelines established in D.82-01-103.

1. Incremental Heat Rates

One significant issue in this case was how often a utility's incremental heat rates should be revised for determining prices to small power producers. Incremental heat rates, which reflect the efficiency ~~by~~ with which utilities can burn fuel at the margin, are one component in the determination of the marginal cost of electricity. IHRs vary depending upon what plants are in operation at any particular time.

Currently, incremental heat rates are determined bienially in the utilities' general rate cases, with heat rates varying by time of day and season. These incremental heat rates are used for determining the prices during the two-year period after a rate case is completed, using fuel costs which are updated quarterly (for PG&E and SCE) or three times a year (for SDG&E). If actual incremental heat rates deviate from the projected average heat rate developed in a rate case due to hydro conditions or any other reason, this change is not reflected in the quarterly prices.

QFs generally favor using the average annual heat rate approach because it provides more price stability. Administratively, QFs also object that utilities may deviate from the average annual heat rate when it suits their interests (e.g., when hydro conditions are favorable and the incremental heat rates generate relatively low prices). PG&E suggests that average annual heat rates be used now, but suggests that projected actual year heat rates (accounting for hydro conditions) might be desirable in the future to more closely reflect actual shortrun operating costs.

By separate petitions for modification filed September 10, 1982, CMA and Imotek, Inc. ~~petitioned~~ asked the Commission to clarify D.82-01-103, and find that utilities should use average annual incremental heat rates for determining avoided costs, as determined in the most recent rate case. The petitioners argued that actual year heat rates create instability in QF prices and are unverifiable. We will ~~incorporate~~ respond to this petition in~~to~~ this opinion.

We resolve that, for now, average year incremental heat rates should be used in the determination of avoided costs, as determined in the utilities' rate cases. We have no procedure at this time for verifying more current estimates, and we do not think it ~~is~~ appropriate to adopt more frequent estimates without giving parties the opportunity to comment on the methodology. However, we conclude that actual year incremental heat rate calculations would be preferable because they ~~would~~ more accurately reflect actual marginal operating costs. QFs that are able to respond to the higher price signal in a dry year, for example, would have a greater incentive to provide energy when it is more needed. On the other hand, small hydro producers ~~who~~ whose fluctuations in electric supply parallel ~~to~~ those of utility hydro ~~operations~~ plants are likely to be overpaid using average hydro years, as in the current method, since they would be likely to produce relatively little in low hydro years (when actual avoided costs are relatively high) and relatively more in high hydro years (when actual avoided costs are relatively low).

While we are adopting average annual heat rates now, we will ask utilities by September 30, 1983 to make proposals for a procedure to use projected actual year incremental heat rates. The utilities in their proposals should clearly set forth ~~establish~~ ~~clearly~~ how they intend to forecast hydro conditions which would then be used to ~~establish~~ ~~a~~ forecast ~~of~~ actual year heat rates. ~~and other factors which affect incremental heat rates.~~ The IHR forecasts probably should be made in the spring to take into account hydro conditions. We will not adopt any proposal until parties have had an opportunity to review and comment on it. Utilities should not deviate from the current two-year review procedure until the deviation has been ~~expressed~~ expressly approved ~~approval has been granted~~ by this Commission.

Another issue raised by staff was how to handle new plants that come on ~~time~~ line which effect IHRs. D.82-01-103 at page 31 states ~~decided~~ that IHRs determined in rate cases should not include new power plants, because both the operating dates and operational characteristics of new plants are generally unknown. ~~(page 31)~~ However, should a new facility begin operation between cases, staff recommends that the IHRs be revised in an ECAC proceeding. We will adopt this suggestion.

Both SDG&E and Edison argue that they should not file incremental heat rate data since ~~it is not an~~ such data are not explicit output of their models. The utilities use probablistic models, which predict the likelihood of a particular plant being on line in any particular hour, and estimate the expected average electricity price based on that model. At some cost the models could be adapted to produce incremental heat rates as outputs. We agree with small power producers that such information would be valuable, and should be provided. Current and expected heat rate data would provide QFs ~~a more realistic~~ with the ability to determine more realistically prices in future periods. Such costs currently are included as utility administrative expenses, ~~in rate cases.~~ Such accounting would ~~is~~ appropriate ~~at this time~~ in this case.

2. ~~Issues Relating to~~ Marginal Fuel Costs

Many of the parties ~~in the case~~ were concerned with the fuel costs used in determining the avoided energy costs. Concerns were raised whether ~~to use~~ forecasted fuel prices, prior period fuel prices, or retrospective prices, should be used, and how ~~to~~ the determination ~~determine what~~ of the marginal fuel ~~is marginal~~ at any particular time, would be made.

Currently, the energy prices are set by utilities at the beginning of a quarter, and QFs can anticipate that payments will be based on those prices throughout the quarter, except for SDG&E which establishes rates three times a year in ECAC. Adjustments are not made at the end of the quarter to reflect actual conditions during that quarter. This procedure gives QFs a clear and predictable price upon which they can base operations for future periods, but it also results in a relatively less accurate determination of the shortrun operating costs than if prices were established retrospectively with fuller knowledge of what actually occurred. Some suggestions were made in the proceeding that the prices be adjusted at the end of the quarter to reflect actual prices paid during the quarter for fuel. Payments to QFs would be retroactively adjusted at the end of the quarter to ~~reflect~~ coincide with actual fuel prices paid during ~~the~~ that quarter. ~~for fuel.~~

We conclude that the current procedure of prospectively establishing prices is preferable. This procedure gives QFs a clear price signal from which to determine its operations for the upcoming quarter. In reaching these prospective determinations, we will attempt, as accurately as possible, to project ~~now~~ the ~~fuel prices and~~ fuel mix ~~that~~ which will occur in the future quarter. Any variations in the projected price should likely be as ~~likely to be as~~ high as they would be low, and deviations should cancel out over time. Retrospective adjustment would undoubtedly create significant controversy, because it would and ~~would~~ destabilize the market for small power producers.

In D.82-11-087, the Commission ordered the utilities to use ~~projected~~ current natural gas prices ~~to be used in~~ for the determination of prospective ~~marginal~~ avoided operating costs, but to continue to use oil ~~in~~ into inventory when oil is the marginal fuel. We will continue to adopt this approach for now, though we would consider refining the oil and natural gas price numbers ~~to projections (instead of current)~~ in the future.

~~PG&E raised a concern that since natural gas prices are established by this Commission, forecasting such prices might involve speculating on Commission decisions. We do not find this concern to be an overwhelming problem. Utilities should forecast their natural gas prices as accurately as possible.~~

For now, we conclude that projecting oil ~~and natural~~ gas price would be unduly complicated ~~and would~~

A major ~~issue~~ controversy in this case was the determination of whether oil or gas is the marginal fuel at any particular time. In recent months, oil in inventory has been more expensive than natural gas. QFs have been concerned that utilities have been burning oil while claiming that natural gas is nearly always the marginal fuel. In response, utilities argue that they must burn oil in inventory either to avoid underlift payments, or for various other reasons which preclude oil from actually being the marginal fuel. I.E.P. questions the utilities' assertions and suggest, as a simplifying assumption for calculation, that oil should be presumed to be the incremental fuel on any day it represents 10% of the generation mix. Staff in evaluating this issue concludes that oil is not generally an avoided fuel at this time, and that the 10% oil mix assumption is arbitrary.

It appears that the question of whether oil or gas is the marginal fuel will involve specific issues that vary in each quarter. Accordingly, our approach will be to ask each utility ~~utilities~~ to file its ~~its~~ projected marginal fuel mix in each quarter, and allow parties an opportunity to critique these projections. Each quarter the utilities should also submit information on their actual experience in the prior quarter. Any decisions reached by the Commission to modify these prices should provide guidance for future quarters.

Much time was spent in this proceeding on the issue of whether Edison avoided oil in the first quarter of 1982, or whether it primarily avoided ~~fuel was predominantly~~ gas. As some of the parties point out, the resolution of this issue has implications for future quarters, as well. Edison argues that while oil was burned during this past year, it was not marginal ~~is~~ because it was burned either for testing or to avoid underlift charges in Edison's ~~their~~ long-term contracts. In Edison's response ~~This~~ appears to be accurate. We conclude that the basic conceptual problem is that the oil prices used in the determination of avoided costs are based on long-term contract prices and therefore may not reflect current fuel markets. When a utility avoids burning oil, it may not be able to avoid the full long-term contract price paid for it when it must either sell the oil on the spot market at a price less than the contract price, or refuse to take additional oil from its supplier to control inventory and pay underlift charges. It appears to be reasonable that the avoided cost therefore should be based either on the spot market price, or the long-term price less the underlift charge. The utilities apparently simply assumed that the avoided cost of oil ~~is~~ was less than gas when underlifts are taken into account and therefore assumed ~~the~~ that their avoided fuel ~~is~~ was natural gas. Given the current oil and gas mix and the current price relationships, such a simplifying assumption seems reasonable.

We cannot agree that oil should be presumed to be the incremental fuel when it is 10% of the daily use. Such a standard would be arbitrary. We are sympathetic to a more detailed analysis of marginal oil use in future proceedings in the determination of the marginal energy costs. The issue of whether oil or gas is the marginal fuel is complex, and will depend upon specific circumstances. This is one ~~is the kind of issue~~ that we would expect to arise in future proceedings to review ~~of~~ the utilities' price offers, which we describe below.

Another issue in the proceeding is whether the fuel used to warm-up facilities should be viewed as marginal and calculated in the avoided cost payment. We agree with staff that the cost of warm up fuel cannot be included at this time, since it is unclear that such fuel is avoided as a result of ~~from~~ purchases from QFs.

Another issue relating to fuel costs is whether SDG&E should use its G-61 commodity rate for determining the avoided natural gas costs for its electric utility generation. The staff and others recommend that the higher GN-5 rate be used, which is the rate established for pricing between SDG&E's gas and electric departments. The G-61 rate is the general commodity rate which SDG&E purchases all of its gas requirements.

We conclude that staff's position is correct. When the electric department of SDG&E purchases electricity from a QF, ratepayers avoid electric production with costs derived from the GN-5 rate for the purposes of calculating SDG&E's electric rates. By establishing QF prices using the GN-5 rate, ratepayers are indifferent between purchases from ~~of~~ QFs and utility generation, consistent with avoided cost principles. To base prices on the G-61 rate would result in an underdevelopment of QF resources, leading to uneconomic use of natural gas in utility boilers. Use of the G-61 rate would also result in an inconsistent pricing system between QFs in Edison's and SDG&E's territory. Edison purchases gas from Southern California Gas Company at the GN-5 rate. It would be inconsistent for SDG&E to impute a lower gas rate simply because it is an integrated utility. We also note that PG&E currently derives its avoided cost prices from the equivalent of the GN-5 rate.

Utilities argue that fuel is not avoided when it is being burned to maintain spinning reserves. By definition, we agree. In the event fuel is being burned in the facility to allow it to be available for future periods, the availability of QFs does not allow the utility to avoid that fuel.

It is evident that the determination of the marginal fuel costs for utilities will remain a controversial subject and that the parties will want to be involved in reviewing the utility's ~~proceeding~~ determination. As CMA points out, the dollars involved are large and will undoubtedly grow in the future as the QF market develops. It is important that we establish an understandable and balanced forum in which parties can review and comment on these prices.

We will therefore adopt the following procedure. In the case of PG&E and ~~SDG&E~~ Edison, we will order the utilities to file prices for energy payments one month prior to the quarter in which the energy prices apply. These prices ~~and~~ a detailed description of the assumptions used to ~~in~~ derive ~~ing~~ them should be filed with the Commission. In addition, the utility ~~shall~~ should make available this information to interested parties for their review. In the event either staff or the interested parties object to the prices proposed, a motion to adjust the price may be filed to the Commission. In the motion, the specific concern must be stated and a recommended resolution suggested. The Commission will decide what further action to take depending upon the nature of the motion.

In the event no action is taken by the Commission by the time a quarter begins, the utilities' prices will go into effect. These prices may be adjusted upward and applied retrospectively in the event the Commission later reaches a determination that the prices posted were too low. However, no downward adjustments will be made retrospectively to avoid pricing uncertainty for QFs.

SDG&E currently is establishing its prices three times a year in ECAC proceedings. We will continue this procedure. Like ~~the SCE~~ Edison and PG&E, SDG&E should spell out the ~~its~~ assumptions used in deriving its numbers.

~~Obviously,~~ We expect utilities to forecast as accurately as possible their actual marginal operating costs for future quarters [illegible] their expected fuel mix [illegible]. We expect that as we reach decisions relating to various issues regarding price in the future, utilities will incorporate those decisions. Over time the ~~utility's~~ utilities' procedures should become fairly understandable and routine. We have no doubt that parties will question utility determinations, and we expect to review them carefully. However, we do not intend to relitigate issues in proceeding after proceeding.

For this procedure to work, it is incumbent upon utilities to present their information clearly and understandably. QFs must be able to understand how prices are being determined to make intelligent investment decisions. We expect that utilities will keep all data relating to QF prices well organized in a central place to permit parties to review the calculations.

C. Adjustments to Energy Prices

A number of issues were raised in the proceeding regarding adjustments to energy prices for various purposes. We ~~turn to~~ consider these issues in this section.

1. Avoided Transmission and Distribution Costs

Little or no evidence ~~is~~ was presented in this proceeding demonstrating that QFs allow utilities to avoid transmission and distribution system costs. Therefore, none are included in the avoided cost payments filed by the utilities. We find this approach to be appropriate at this time.

2. Variable Operations and Maintenance Costs

There was general agreement that variable operating and maintenance costs should be included in the avoided cost determinations. However, PG&E and SDG&E include ~~it~~ these costs in their energy payments while ~~SCE~~ Edison includes ~~it~~ them with capacity payment. For consistency, we will order that ~~it~~ these costs be included as part of the energy payment. In the regular price filings, the assumptions regarding the derivation of variable O&M should be included.

3. Line Losses

D.82-01-103 ordered applicants to "include costs or savings from line losses in the aggregate." (Ordering Paragraphs 6(a) and 8(e)). The Commission created an exception that line losses will be examined individually for "projects one MW or larger developed at sites remote from load centers."

The record in this proceeding indicates that ~~insufficient study has been performed~~ this issue is inadequately studied by the utilities to determine appropriate loss rates. PG&E's study does not differentiate between remote sites and other QFs, while SDG&E and ~~SCE~~ Edison have not undertaken a study at all. In the absence of such a study, we will adopt ~~staff's suggestion that~~ a loss factor of 1.0 to be applied by all utilities ~~for~~ for all QFs ~~in all utilities at this time~~. This resolution essentially assumes that QFs line losses are equal to utility plant losses, which seems reasonable lacking better information on this subject. We will also adopt the suggestion that loss factors be established for three voltage levels.

Additionally, we will ~~also~~ adopt the staff position that studies be performed by utilities to determine the aggregate line losses of QFs. ~~We will adopt a schedule that~~ PG&E should report in 6 months, and SDG&E and ~~SCE~~ Edison in one years.

The record indicates that at this time adjust~~ing~~ments for line losses for remote sites is beyond our ~~sophistication, at this time.~~ current capabilities. We will therefore suspend the use of specific line losses for remote sites until the problem is better understood. As part of the studies required of utilities, we will ask for an analysis of how to identify remote QFs, and how to reflect a different loss rate. Until such studies are performed, remote QFs will not have individual line losses adjustments.

PG&E suggests that individual line losses should be established. This approach would not comply with D.82-01-103. The individual determination of line losses would create great complexity, and would very likely result in frequent disputes between the utility and QFs. Aggregate line loss~~es~~ determinations are appropriate at this time.

3. Transformer Losses

An issue was raised about whether transformer losses should be included in the avoided cost payment, and if so, how that loss should be determined. The staff suggests an ~~elegant~~ appropriate solution: simply place the meter on the utility side of the transformer, thereby automatically accounting for the transformer losses in the meter reading. We will adopt this ~~resolution~~ recommendation. If a QF desires to have a meter on its side of the transformer, it may negotiate a transformer loss rate with the utility.

D. Refusal to Purchase and the Hydro Spill Rate

One of the more complex issues relating to energy payments regards the periods in which a utility may refuse to purchase from QFs, or offer lower prices to reflect current conditions in the utility system. As described earlier, price is established for electricity purchases for a time period based on projected average marginal costs. The actual avoided costs incurred will vary throughout the period, varying around the average established.

There are certain conditions in which the actual avoided costs deviate so significantly from the average that special treatment may be warranted. In particular, D.82-01-103 found that ~~in the condition where~~ when the utility actually incurs costs by purchasing energy from a QF (a "negative avoided cost" condition), the utility should have the right to curtail QFs. In D.82-04-71, the Commission also concluded that ~~in a condition where~~ when a utility must spill water over its own hydro electric facilities in order to purchase from QFs, a lower price is appropriate. The decision did not, however, permit a lower price to be established during periods when economy energy is purchased or ~~in other conditions~~ when avoided costs are positive. Anticipated economy purchases were to be averaged in the avoided cost applied for the entire time period.

Allowing utilities to pay lower rates or curtail customers unexpectedly creates significant complications for QFs because of ~~awkward~~ unwieldy notification requirements and price instability. It is also very difficult to establish what the lower rate during periods of economy energy or hydro spill should be. For this reason ~~the Commission~~ we previously decided to very narrowly define the period and to include the expected economy energy purchases in the average rate for the entire period. What is lost in precision is gained in administrative workability and price certainty.

The parties in this proceeding suggest alternatives and refinements to this approach. Certain QFs suggested fixed limits on the number of hours that they ~~could~~ can be curtailed or offered the ~~to be~~ lower~~ed~~ hydro spill rate. A number of proposals were made to limit the applicability of curtailment and hydro spill conditions. ~~applicability~~. Staff proposed that a 100-hour limit be established for curtailment and hydro spill conditions ~~application~~, while the IEP suggested that a total of 200 hours be applied ~~for~~ to both. Staff suggested that in the event the QP is required to curtail more than 100 hours, ~~that~~ it should be paid for the additional hours based on what it would have produced in event curtailment had not been invoked. Staff argues that it is unlikely that QPs would be curtailed for longer than 100 hours in any event, and the added certainty about being paid makes the provision worthwhile. Utilities, in general, oppose such restrictions in the contract, arguing that such provisions would be inconsistent with D.82-01-103, and could tend to overpay QPs.

Procedurally, we agree with the utilities that restrictions on the number of hours that curtailment and hydro spill conditions apply would be ~~directly~~ inconsistent with D.82-01-103 and D.82-04-71. Those decisions attempt to very narrowly define the conditions in which either term could be applied in order to reduce uncertainty for QPs. However, lacking any evidentiary basis, neither placed limits on ~~in~~ the application of those provisions.

While we are sympathetic of the concerns of QPs that they must understand what the outside limit of the application of these provision could be, we have no evidentiary basis to determine what that limit should be. We will, therefore, order utilities to undertake studies ~~a study~~ to estimate the maximum probable limit for hydro spill and curtailment conditions ~~that is~~ likely to occur in future years in order to provide QPs with more certainty about the likelihood of these provisions being imposed. These studies should be submitted to the Commission and provided to parties within ~~six months~~ 3 months. Based on these studies, we will entertain proposals to modify D. 82-01-103 to establish limits in the contracts for the refusal to purchase and the hydro spill conditions.

1. The 600-Hour Curtailment Option

Utilities have suggested that as an option, QFs be offered a curtailment provision that applies to periods of economy energy purchases, and which includes a 600-hour annual limit. While we welcome and encourage such an offer being available as an option, ~~such an~~ the offer itself is outside the scope of these compliance proceedings. The standard offer should be based on the negative avoided cost and hydro spill conditions outlined in the original decisions. We will view the 600-hour curtailment provision option as a nonstandard contract, for now, because we have not reviewed the details of how the curtailment provisions would work or how ~~it~~ they would affect the marginal energy prices. [illegible]

2. Implications of Curtailment on Firm Capacity Payments

An issue arose on how curtailment provisions relate to the firm capacity provisions. We conclude that QFs should be presumed to be available during curtailment periods, and should be eligible for any output, payments (even if not actually provided), since the QFs are being curtailed by the utilities. We will therefore adopt the staff's suggestion that the contracts be modified to reflect ~~this~~ those conclusions. This resolution comports with D.82-01-103 (at page 81), which states that QFs signing ~~a~~ firm capacity contracts should be paid for capacity during time of non-purchase. ~~(Page 81).~~

3. Internal Use of Energy During Curtailment

Certain Parties suggest that cogeneration facilities operating under simultaneous purchase and sale contracts be permitted to use energy internally in the event of curtailment. We reject this proposal. As staff points out, curtailment is likely to occur in periods of extremely low demand, and any further reduction in demand caused by internal use of electricity would likely reduce the value of curtailment, and be costly for the utility. If a QF agrees to sell all of its output under simultaneous purchase and sale, the output should be subject to curtailment as for any ~~like any~~ other QF.

4. Notice Requirements

In order to assist QF planning ~~for the to plan~~, longer notice requirements for curtailment were suggested. D.82-01-103 established notice guidelines. We do not see any reason to change them here. Of course, utilities should give as much notice as possible of impending curtailment.

E. Price Floors and Levelized Payments

Suggestions were made in this proceeding to establish a price floor for energy payments and to levelize energy payments. Both of these suggestions are clearly outside the scope of these compliance hearings. The levelized payment option was addressed and rejected in D.82-01-103 (Pages 55-56), and the floor concept was not discussed at all.

If a floor price were established, some reduction of the energy price would be necessary to remain within the avoided cost concept. The floor reduces QF risks, ~~and~~ creates the possibility that at some point the floor price paid might be above avoided cost. In return for this security, a lower price during the rest of the time is appropriate. We would encourage utilities to negotiate nonstandard contracts with floors or levelized payments if QFs are interested.

Further Modifications of Contracts

This ~~is an interim~~ decision is the first in these applications. We will issue later in 1983 another ~~a final~~ decision regarding other issues raised in this proceeding, which may result in further modifications to these contracts.

QFs interested in signing contracts between now and the time of an final decision may be reluctant to sign until the Commission resolves the remaining issues. To relieve this uncertainty somewhat, we will give QFs who sign contracts between the effective date of this decision and the time a final offer stemming from these compliance hearings takes effect the opportunity to switch from the interim contract to the final contract. QFs may not switch from one standard offer to another, but may adopt the final version of the particular offer signed.

Findings of Fact

1. The California Public Utilities Commission has a continuing interest in promoting the development of cogeneration and small power production facilities.

2. By D.82-01-103 in Order Instituting Rulemaking (OIR) 2 each electric utility was required within 45 days of the effective date of that order to file standard offers to be made to qualifying facilities for (a) as-available energy and capacity based on a short-run avoided cost methodology, (b) firm capacity based on a short-run marginal cost methodology, and (c) energy and capacity provided by QFs below 100 KW in size.

3. The offers required by D.82-01-103 were included in the applications which are the subject of this order.

4. Evidentiary hearings were held with respect to A.82-03-26 (PG&E), A.82-03-37 (Edison, and A.82-03-78 (SDG&E) to determine each of these utilities' compliance with the requirements of D.82-03-103 and other related orders in OIR 2; the reasonableness of provisions included in the utilities' offers, but not specifically addressed in the OIR 2 decisions; and the factual bases for the prices contained in each of the standard offers.

5. Consideration of issues recited in Finding 4 above for A.82-03-62 (Sierra Pacific Power Company), A.82-03-67 (Pacific Power & Light Company) and A.82-04-21 (CP National Corporation) have ~~has~~ been deferred until the resolution of and final decision in A.82-03-26, A.82-03-37, and A.82-03-78.

6. An additional issue properly addressed during the evidentiary hearing was the appropriate methodology for determining capacity costs, based on the shortage cost concept, under a utility's firm capacity standard offer. Revisions of the methodology for calculating a utility's as-available capacity payment is reserved for the utility's general rate case as specified in D.82-04-071.

7. For a decision to be issued in this proceeding prior to the end of 1982, only certain issues raised during the hearings and in briefs can be addressed. The remaining issues which are not resolved by this order will be considered as early as possible in 1983.

8. The issues chosen for consideration in this order relating to the utilities' capacity and energy payments will provide QFs with sufficient options to make the economic decisions necessary for determining merits of proceeding with or continuing a particular project.

9. Payments for as-available capacity do not reflect any value for contract length, notice, termination or sanctions, since such provisions are not part of an as-available offer.

10. Firm capacity is viewed as an increase in the utility's supply of electricity with corresponding performance standards, termination provisions,and sanctions.

11. D.82-01-103 requires that (a) firm capacity payments reflect availability during system peak periods including such factors as dispatchability; reliability; contract duration, termination, and sanctions; scheduling of outages; and availability during emergencies; (b) the value of each of these factors be calculated based on standards comparable to performance standards the utility would impose on its own plants; (c) the sum of each of these factors be included in the resulting capacity value; (d) a QF that exceeds operating standards normally expected of utility plants be able to earn a higher capacity payment; and (c) when resource limitations exist to reliable operations, plant capacity factor may be a better measure of reliable operation than availability.

12. Each of the utilities proposed a different approach to performance standards in their firm capacity standard offers.

13. Three general types of performance standards have been proposed in the utilities' filings--the first based on a level of peak period availability (PG&E's Option 1), the second based on a level of peak period output (PG&E's Option 2, SDG&E's Option 2, and Edison's single option), and the third requiring only a certain contract duration with no specific requirement for peak period output or availability (SDG&E's Option 1).

14. PG&E's Option 1 availability standard requires the QF to be dispatchable and available during emergencies and to maintain a certain level of peak period reliability. The option also imposes sanctions and termination provisions for nonperformance and allows for scheduled maintenance.

15. As modified herein, PG&E's Option 1 is reasonable and in compliance with D.82-01-103.

16. PG&E's Option 2 output standard ensures reliable operation during peak periods and emergencies and, like Option 1, imposes ~~sanctions and~~ termination provisions for nonperformance with an allowance for scheduled maintenance.

17. As modified herein, PG&E's Option 2 is reasonable and in compliance with D.82-01-103.

18. An 80% summer peak hour availability or output requirement under PG&E's Options 1 and 2 is reasonable, and, with PG&E's revised reduction of payments provisions, is a sufficiently flexible ~~reduction~~ measure of QF performance.

19. SDG&E's Option 2, an output-based performance offer, requires only a 50% level of output during all peak and semi-peak hours. This standard of performance is not commensurate with the utility plant avoided by QF purchases, which plant would have a higher level of peak period availability than 50%. Additionally, termination provisions and sanctions are not imposed for failure to meet this standard.

20. SDG&E's Option 2 is not in compliance with D.82-01-103.

21. Edison's output-based performance standard fails to focus on peak-period availability, with a 50% performance level which is too lenient for the peak period and an emergency availability requirement which is too stringent and places too much emphasis on one aspect of peak period availability.

22. Edison's output based performance standard is not in compliance with D.82-01-103.

23. SDG&E's Option 1, which merely requires a contract commitment for a specified period with no peak period availability or output requirement, fails to reflect the performance standards for firm capacity offers required by D.82-01-103 and is not an option to purchase firm capacity as defined by that order.

24. SDG&E's Option 1 is not in compliance with D.82-01-103.

25. It is necessary for the utilities to refile their standard offers for firm capacity to conform to D.82-01-103.

26. To comply with D.82-01-103, all utilities must file standard offers with payments options based on both a QF's availability and energy production. PG&E's Options 1 and 2 serve as basic models for such options, as modified consistent with the findings in this order.

27. To achieve overall compliance with D.82-01-103 and this order, the following principles should be incorporated in any utility's firm capacity standard offer:

a. Dispatchability must be defined to give a utility the right to require only increases, not decreases, in a QF's operation. Any other definition permits unwarranted and unreasonable interference with a QF's operations. Dispatchability need not be limited to on-and midpeak periods and emergencies if an approach like that used in PG&E's Option 1 is adopted.

b. Each payment option must provide for payments in excess of a utility's capacity costs for QFs whose performance exceeds that of the utility's plants. To receive the higher payment, the QF's performance must consistently exceed the minimum level of availability of the peaking unit used as a proxy to calculate the utility's shortage costs. A peak period availability or capacity factor in excess of 85% is a reasonable ~~reasonable~~ performance standard to require of QFs entitled capacity payments in excess of 100% of the shortage cost proxy. An 80% reliability factor is reasonable for offers based on 100% of a utility's capacity costs. For an availability option which permits the higher payment, a more certain measure of the QF's dispatchability is required than presently provided in PG&E's Option 1 in order to determine whether and at what level the QF actually exceeds the utility plant's operation.

c. PG&E's proposal with respect to the treatment of small hydro QFs whose payments are based on the five dry year average, but are experiencing a "drier" year than that average, is reasonable and should be adopted for all utilities with one modification. It is reasonable to permit hydro QFs to be paid during the "drier" year for the amount of capacity, if any, actually delivered to the utility. It is reasonable to apply the provisions governing reduction or reinstatement of payments adopted herein to the year following the "drier" year.

d. Essential elements of a scheduled maintenance standard are a reasonable allotment of days for both routine maintenance and major overhauls, sufficient notice to aid utility system planning, and appropriate timing to avoid periods of greatest demand on the utility system. The scheduled maintenance allowance should be uniform for all utilities and should include all of the elements and requirements listed in the discussion of scheduled maintenance in this decision.

e. PG&E's revised approach for reducing payments under either its availability or energy output payment options for nonperformance is reasonable and should be adopted in all utility standard offers for firm capacity. This modified approach permits payments for capacity actually delivered during a 15-month probationary period with the potential of the original payment level being reinstated or the QF's capacity derated at the end of the period depending on the QF's performance during the peak months. The difference between the contract capacity and the reduced capacity is appropriately subject to contract termination provisions. For the capacity actually delivered during the probationary period, an allowance or credit for forced outages at the level otherwise specified in the utility's standard offer should be included. No retroactive payment is necessary.

28. No provision is required in firm capacity standard offers to permit as-available capacity payments during a start-up period. A QF seeking as-available capacity payments during the period before its firm capacity operations commence has the option of signing a short-term as-available capacity contract.

29. Each of the utilities properly responded to D.82-01-103 by including termination provisions in their firm capacity standard offers.

30. The utilities' termination provisions must be reasonable.

31. Termination provisions should encourage QFs to fulfill their contractual obligations, provide reasonable certainty of the consequences of termination, and make the utility and its ratepayers whole.

32. There is no reason for termination provisions to vary greatly between utilities with respect to the basic requirements of such provisions.

33. Liquidated damage clauses, which limit damages to the amounts or formula prescribed in the clause and provide a party with advance knowledge of how the damages for termination will be claculated, are desirable and reasonable for inclusion in every utility's standard offer for firm capacity.

34. It is reasonable for the liquidated damage clause to cover reimbursement of unearned capacity payments. The utilities' methods for calculating this reimbursement are reasonable, with the exception of the need for a uniform imposition of and standard for interest to be charged on the amount refunded.

35. The published Federal Reserve Board three months Prime Commercial Paper rate (plus 50 points for SDG&E) is currently used to calculate interest on the utilities' various accounts and is a reasonable rate to apply to the repayments required of a QF who terminates its firm capacity contract.

36. It is reasonable for the utilities to include liquidated damage clauses to cover the replacement costs associated with QF termination and to provide a reduction or elimination of those damages for a QF which gives the prescribed advance notice of its termination.

37. Each utility's standard offer for firm capacity must distinguish between those QF's terminating with prescribed notice, for which replacement damages are ~~reduced or~~ eliminated, and those which do not.

38. The specific notice required for termination should depend on the amount of capacity being terminated and may be utility-specific. The proposals of SDG&E and PG&E are reasonable; Edison should be required to prescribe a table similar to those proposed by PG&E and SDG&E varying the length of notice according to the amount of capacity being terminated.

39. For QFs terminating without prescribed notice, it is reasonable for all of the utilities to adopt PG&E's approach to calculating the damages to be added to the refund of overpayments, with one modification. The adopted damage formula should reflect the time needed, as reflected in the notice table, to replace the lost capacity.

40. The utilities' calculation of damages can properly refer to future capacity prices.

41. Any requirement that a QF shall provide~~s~~ evidence of its ability to make potential termination payments is burdensome and unreasonable.

42. Each utility's firm capacity standard offer should include examples of the operation of its termination provisions.

43. A reduction in capacity should not result in a complete termination of an agreement; however, the termination provisions can be applied to the amount being reduced.

44. D.82-01-103 clearly provides for a limitation of one year to conversions from the simultaneous purchase and sale of energy to the sale of surplus only and for the application of termination provisions ~~for~~ to QFs ~~who~~ which undertake such a conversion.

45. It is reasonable for a utility to provide that a QF which undertakes the conversion referred to in Finding 44 above ~~is~~ be subject to termination provisions only for the amount by which the contract capacity is reduced. This approach complies with D.82-01-103 and the application of termination provisions to capacity reductions and should be used by each of the utilities.

46. Edison's inclusion of a notice requirement for the termination of an as-available capacity contract is unreasonable, is in conflict with D.82-01-103, and should be deleted. That decision specifically states that termination provisions are not appropriate for offers to purchase as-available power.

47. For the standard offers that are the subject of these compliance hearings, D.82-01-103 requires that avoided costs be defined according to avoided short-run marginal costs, ~~and~~ the component of this definition, avoided shortage costs, should be the basis for firm and as-available capacity payments.

48. In D.82-01-103 and D.82-04-071 the Commission adopted the capital costs of a combustion turbine as a proxy for shortage costs.

49. D.82-04-071 specified that as-available capacity payments are to be based on the full cost of the combustion turbine and that any refinements of this proxy would only be considered in future general rate cases.

50. Pursuant to an ALJ ruling, the utilities were allowed to introduce into these compliance hearings methodologies which adjust the full combustion turbine shortage cost proxy for firm capacity payments.

51. Combustion turbine costs vary from one utility to another because of different financing costs, environmental requirements, and locational factors.

52. It is not reasonable for estimates of combustion turbine costs calculated at a given time to vary from one utility to another on the basis of general economic indices.

53. Edison's combustion turbine capital cost estimate of \$415/kW for a January 1, 1982 plant on-line date is reasonable.

54. Staff's 23-year plant economic life for the Edison combustion turbine estimate is reasonable and consistent with D.93887.

55. The escalation and discount rates used by staff for the Edison combustion turbine cost estimate are reasonable for the purposes of that estimate.

56. Combustion turbine fuel inventory costs will escalate over the life of the plant and, for the purposes of the Edison combustion turbine cost estimate, 50% of the staff oil escalation rate is a reasonable figure to use for fuel inventory escalation.

57. Edison's fixed administrative and general costs assumption is reasonable for ~~the~~ purposes of calculating its combustion turbine cost estimate.

58. The increased system marginal operating costs resulting from the operation of the combustion turbine are more accurately reflected in avoided energy costs ~~not~~ rather than avoided capacity costs.

59. SDG&E's 1982 combustion turbine capital cost estimate of $400/kW is reasonable for the purposes of QF pricing.

60. The SDG&E incremental cost of capital for the purposes of combustion turbine cost estimation is 15.5%.

61. Accurate combustion turbine costs for SDG&E include fixed administrative and general costs and staff's proposed escalation rates.

62. Staff and SDG&E are in agreement on fuel inventory costs, fixed O&M costs, and plant economic life assumptions for combustion turbine cost estimation, ~~and~~ these assumptions are reasonable.

63. The staff's 1982 generic combustion turbine capital cost of $450/kW is reasonable for the purposes of PG and E's QF pricing.

64. The escalation rates used by staff for Edison and SDG&E combustion turbine cost estimation are also accurate rates for PG&E combustion turbine costs.

65. A 15.5% incremental cost of capital is a reasonable assumption for combustion turbine cost estimation for PG&E.

66. An accurate PG&E combustion turbine cost will include a fuel inventory cost commensurate with that found reasonable for Edison.

67. Plant economic life, fixed operation and maintenance costs, and fixed administrative and general cost assumptions adopted for combustion turbine cost estimation in D.93887 are reasonable for the purposes of combustion turbine cost estimation used for firm QF pricing.

68. PG&E proposes to adjust the combustion turbine shortage cost proxy used to calculate firm capacity prices to reflect year-to-year variations in reserve margins, using the company's Energy Reliability Index (ERI) methodology.

69. The ERI methodology is an innovative approach to measuring shortage costs.

70. The ERI methodology is conceptually flawed and biased downward because it only allows for downward adjustments in the annual shortage cost proxy and not upward adjustments.

71. A precise shortage cost methodology will allow for upward adjustments in the equilibrium shortage cost when loss of load probabilities are greater than the target level.

72. The ERI methodology is conceptually flawed and biased downward because it treats uncertain factors such as plant start up dates and plant maintenance requirements in a deterministic fashion in estimating future shortage costs and reserve needs.

73. ~~Lack of~~ The absence of a sensitivity analysis ~~costs~~ casts doubts on the validity of ERI results.

74. PG&E utilized several erroneous imput assumptions when it used the ERI methodology to derive firm capacity prices.

75. The accurate estimation of future shortage costs requires, to the extent it is feasible, the simultaneous rather than sequential consideration of load management programs, utility resources, and QF power.

76. PG&E's proposed revisions of its firm capacity price methodology (using different load management assumptions in the estimation ~~for~~ of future ERI numbers and retroactive capacity payments if Helms pumped storage plant and Diablo Nuclear power plant startup dates are not realized) do not remove the downward bias in its ERI-based capacity prices.

77. For the calculation of firm capacity prices, SDG&E has proposed shortage cost methodology that adjusts the combustion turbine proxy for year-to-year variations in reserve margins.

78. The SDG&E method is conceptually flawed because it only allows for downward adjustments in the annual shortage cost proxy, not upward adjustments.

79. The SDG&E method is flawed because it does not allow year-to-year increases in shortage costs to be followed by decreases.

80. In calculating firm capacity prices using its shortage cost method, SDG&E did not adequately allow for utility plant start up date uncertainty and included an unrealistic assumption about the 1982 availability of the SONGS 2 nuclear plant.

81. SDG&E did not adequately substantiate its shortage cost methodology nor its input assumptions.

82. Given the same input assumptions, calculation of annual combustion turbine costs using either a plant deferral concept or a real economic carrying charge concept should lead to the same result and either is reasonable.

83. For the calculation of firm capacity prices, Edison has proposed a shortage cost methodology that bases 1982-85 shortage costs primarily on wholesale emergency capacity prices in the California Power Pool Agreement, and secondarily on the Edison-California Department of Water Resources Contract, and the principles of interconnected operations for the Navajo and Four Corners Power Projects.

84. The wholesale contracts that Edison utilizes for 1982-85 firm QF capacity prices are complex energy and capacity exchange agreements that involve shared reciprocal services.

85. The fact that the price of emergency capacity in the California Power Pool has not changed since 1967 despite inflation and narrow reserve margins makes more likely the possibility that this agreement is a mutually underpriced reciprocal transaction that is not an accurate proxy for avoided shortage costs.

86. Edison did not adequately substantiate its claim that the emergency capacity price is the marginal resource avoided by firm QF capacity purchases.

87. The PG&E, SDG&E, and Edison shortage cost methodologies proposed for firm capacity prices in these compliance hearings are unreasonable.

88. Further hearings are required before more refined shortage cost methods can be adopted.

89. The capital cost of the combustion turbine is a reasonable proxy for shortage costs to be used for as-available and firm capacity prices.

90. It is reasonable that energy prices in the as-available, firm and less than 100 kW offers should reflect as nearly as possible a utility's marginal variable operating costs.

91. The current standard offers create unnecessary risks for QFs that energy prices in some future period might not be derived from a utility's avoided costs.

92. It is reasonable for each contract to include language that energy prices will be derived from the utilities marginal variable operating costs, as approved by the Commission, throughout the life of the project.

93. It is not feasible to include an energy price formula in standard price offers.

94. It is reasonable for interested parties to have the opportunity to review and comment on the utilities' calculation of energy prices.

95. The determination of energy rates derived from the utilities' marginal operating costs is in an evolutionary stage. Refinements will emerge over time.

96. It is reasonable for utilities to use average annual estimates, as determined in rate cases, for the derivation of energy prices until the Commission approves a more refined methodology.

97. Actual incremental heat rate and fuel use data filed regularly would be useful for the evaluation of future period energy prices.

98. It is reasonable that the input of new plants which affect the incremental heat rates be determined in an ECAC proceeding.

99. Projected energy prices are less precise than retrospective calculations, but provide more pricing certainty for QFs.

100. Projected natural gas prices more closely reflect marginal operating costs than do historical costs.

101. Oil may be burned to control inventory or for testing without being a marginal fuel.

102. Fuel used to warm-up ~~of~~ facilities is not necessarily avoidable.

103. SDG&E avoids natural gas at the GN-5 rate, not the G-61 rate.

104. Fuel is not necessarily being avoided when used to maintain primary reserves.

105. No evidence now exists that transmission and distribution costs are avoided by QF purchases.

106. It is reasonable that variable operating and maintenance costs be included explicitly in the energy price derivations.

107. Insufficient data exists on line losses at this time. A reasonable assumption is that losses are equal to the line losses of utility plants, ~~in reasonable,~~ thus implying a line loss factor of 1.0.

108. Until sufficient evidence is presented by utilities for the identification and valuation of losses from remote sites, the loss for all QFs can reasonably be established at 1.0.

109. Transformer losses need not be established if the meter is on the utility side of its transformer.

110. Limited evidence exists on the maximum probable number of hours utilities might invoke either for refusal to ~~produce~~ purchase or hydro spill conditions.

111. Restricting the number of hours for hydro spill or refusal to ~~produce~~ purchase is inconsistent with D.82-01-102 and D.82-04-71.

112. The option to pay QFs a ~~lighter~~ higher capacity payment in return for up to 600 hours of curtailment during periods of economy energy purchases, while desirable, is an issue outside the scope of these compliance hearings.

113. Internal use of energy by QFs on simultaneous purchase and sale during curtailment would reduce demand and possibly exacerbate load problems the utility is seeking to solve through curtailment.

114. A levelized or price floor energy option is outside the scope of these proceedings.

Conclusions of Law

1. The Commission should continue to encourage the development of qualifying cogeneration and small power production facilities.

2. The standard offers of PG&E, Edison, and SDG&E should include capacity and energy payment provisions which comply with our decisions in OIR 2 and are reasonable.

3. The capacity and energy payment provision of the utilities' standard offers for as-available capacity and energy and firm capacity should be modified in keeping with the discussion and findings of this decision.

4. To promote the signing of standard offers by QFs this order should be made effective today.

O R D E R

IT IS ORDERED that

1. Within 30 days of the effective date of this order, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E) shall file appropriate amendments to the standard offers included in Applications (A.) 82-03-26, 82-03-37, and 82-03-78 consistent with this decision and the ordering paragraphs contained herein.

2. Each utility's standard offer for firm capacity shall include the following requirements governing the performance standards to be applied to qualifying facilities (QF):

   a. Each standard offer shall include two payment options, one based on a QF's availability and the other based on a QF's energy production or output. PG&E's Standard Offer No. 2, Appendix C, Options 1 and 2, as modified in accordance with this order, shall serve as models for these payment options.

   b. Dispatchability shall be defined to permit the utility to require only increases, not decreases, in a QF's operation. Dispatchability need not be limited to on- and mid-peak periods and emergencies if the utility's payment option based on availability is similar to PG&E's Option 1.

   c. Each payment option for firm capacity shall provide for payments in excess of a utility's capacity costs for QFs whose performance exceeds that of the utility's plants. To receive the higher payment, the QF's performance shall consistently exceed a peak period availability or capacity factor of 85%.

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For offers based on 100% of a utility's capacity costs, a QF shall only be required to maintain an availability or capacity factor of 80%. For a payment option based on a QF's availability which permits the higher payment, each utility shall include in the standard offer a method of determining whether and to what extent the QF has been dispatchable at a level of 85% or better.

d. Each utility's standard offer for firm capacity shall provide that hydro-electric QFs, which have their capacity ratings based on the five dry year average, shall not have their capacity terminated or derated when their failure to meet minimum performance requirements is due solely to the occurrence of a dry year which is drier than the five dry year average. During drier year conditions, a hydro QF shall be paid for the amount of capacity, if any, actually delivered to the utility. Capacity payments shall resume, at the contract price, at the end of the drier year if hydro conditions once again reach the level used to determine the capacity rating. If the capacity of the hydro QF does not reach this level following the drier year, its capacity shall be derated to the new level, capacity payments shall be based on the new rating, and the amount by which the capacity is reduced shall be subject to termination provisions.

e. Each utility's standard offer for firm capacity shall include an allowance for scheduled maintenance which provides as follows: (1) Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. (2) A QF may accumulate unused maintenance hours on a year-to-year basis up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. (3) Reasonable advance notice to the utility of a scheduled outage shall be 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six months for a major overhaul. (4) Major overhauls shall not be scheduled during the peak summer months. Reasonable efforts to schedule or reschedule routine maintenance outside the peak summer months shall also be made, but in no event shall outages for scheduled maintenance exceed 30 peak hours during the summer peak months. (5) No restrictions shall be imposed on the use of the scheduled maintenance allowance during the initial period of operation (i.e., the first six months). (6). Capacity payments shall apply during outages for scheduled maintenance.

f. Each utility's payment options for firm capacity shall include provisions for the reduction of capacity payments in the event the QF fails to meet the minimum performance requirements. For both payment options, a probationary period not to exceed 15 months shall be adopted. For an availability option, like PG&E's Option 1, if a QF fails to meet the minimum performance requirements, it shall continue to receive capacity payments for the amount of dispatchable capacity available during

> the probationary period. If after the expiration of this period, the QF has not demonstrated an ability to provide its full contract capacity to the utility, that capacity shall be derated and subsequent monthly payments limited to the new contract capacity. The amount by which the QF's capacity is reduced shall be subject to termination provisions. For an output option, like PG&E's Option 2, the QF shall earn capacity payments during the probationary period for the amount of capacity actually delivered. If the QF fails to deliver the full contract capacity during each of the following year's peak months, the contract capacity shall be derated to the ~~lower~~ monthly amount of capacity actually delivered during the peak months. The amount by which the QF's capacity is reduced shall be subject to termination provisions. Under both options, for capacity actually delivered during the probationary period, an allowance or credit for forced outages at the level otherwise specified in the utility's standard offer shall be included. The standard offer shall not include a provision for retroactive payments.

3. Edison's single payment option for firm capacity based on a QF's output and SDG&E's firm capacity payment Options 1 and 2 are not in compliance with Decision (D.) 82-01-103 and shall not be included in any standard offer for firm capacity.

4. The utilities' standard offers for firm capacity shall not include provisions for a QF to receive as-available capacity payments during the start-up period prior to the commencement of its firm capacity operations.

5. Each utility's standard offer for firm capacity shall include termination provisions which meet the following requirements:

a. Each utility shall provide for the reduction of capacity payments under the circumstances and in the manner provided in Ordering Paragraph 2 (f) of this decision. Reductions in contract capacity shall not result in a complete termination of the contract but the amount by which the capacity is reduced shall be subject to termination provisions.

b. Each utility's standard offer for firm capacity shall require a QF terminating with prescribed notice to reimburse the utility for unearned capacity payments. Each of the utilities' methods for calculating this repayment, which are otherwise reasonable, shall include the requirement that interest be charged on the amount refunded. The interest shall be the published Federal Reserve Board three months' Prime Commercial Paper rate (plus 50 basis points for SDG&E).

c. The specific notice required for termination with notice shall vary depending on the amount of capacity being terminated. Tables similar to those in PG&E's and SDG&E's standard offers for firm capacity shall be included in each of the utilities' standard offers.

d. Each utility's standard offer for firm capacity shall require a QF terminating without prescribed notice to refund overpayments and to cover the utility's replacement costs for the lost or reduced capacity. The offers shall include a liquidated damage clause calculating this additional payment for replacement costs similar to that prescribed in PG&E's Standard Offer No. 2, Appendix D (which reflects the actual notice given), with one modification. The adopted formula shall reflect the time needed, as indicated by the notice table, to replace the lost capacity. The utilities' calculation of their damages may refer to future capacity prices.

e. The utilities' termination provisions shall not require a QF to provide evidence of its ability to make potential termination payments.

f. Each utility's standard offer for firm capacity shall include examples of the operation of its termination provisions.

g. The requirements of D.82-01-103 with respect to conversions from the simultaneous purchase and sale of energy to the sale of surplus only shall be reflected in a utility's standard offer for firm capacity. Termination provisions shall only apply to the amount by which the contract capacity is reduced as a result of the conversion.

6. A standard offer for as-available capacity shall not include any notice requirement for termination.

7. The utilities shall file firm and as-available capacity prices based on 100% of the capital costs of the combustion turbine, using the combustion turbine cost estimates adopted in this decision.

8. Edison combustion turbine capital costs shall be based on the following assumptions:

(a) $415/kw 1982 combustion turbine capital costs;

(b) 23-year economic life;

(c) escalation and discount rates proposed by staff for Edison in this proceeding;

(d) fuel inventory costs proposed by staff with the exception that staff's inventory escalation rate shall be reduced by 50%;

(e) administrative and general costs which, on a levelized basis, shall be equivalent to 1% of the combustion turbine capital cost;

(f) no differential fuel credit; and

(g) fixed operation and maintenance costs agreed to by staff and Edison in this proceeding.

9. SDG&E's combustion turbine capital cost shall be based on the following assumptions:

(a) $400/kw 1982 combustion turbine capital cost;

(b) 15.5% incremental cost of capital;

(c) fixed administrative and general costs commensurate with those adopted for Edison;

(d) fuel inventory costs, fixed operations and maintenance costs and plant economic life agreed to by staff and SDG&E in this proceeding; and

(e) staff's proposed escalation rates for SDG&E.

10. PG&E's combustion turbine capital cost shall be based on the following assumptions:

(a) $450/kw 1982 combustion turbine capital costs;

(b) escalation rates adopted for SDG&E;

(c) a 15% incremental cost of capital;

(d) fuel inventory costs commensurate with those adopted for Edison; and

(e) plant economic life, fixed operation and maintenance costs; and fixed administrative and general costs adopted for combustion turbine cost estimation in D.93887.

11. More refined shortage cost methodologies such as those proposed by the utilities in this proceeding for firm capacity payments shall be examined for possible application to QF pricing applications in SDG&E's and PG&E's current general rate cases and hearings on Edison's 5-year energy price offer (A.82-04-46). Any revision in capacity prices that is adopted by the Commission because of this examination shall only apply prospectively to QFs that sign after the date of the orders in those proceedings.

12. Each utility's standard offer for energy ~~payments~~ shall reflect the following:

a. Each utility shall modify its as-available and firm capacity contracts, and its contract for QFs less than 100 kW to state that energy prices will be derived from the utilities' full avoided operating costs, as approved by the Commission, throughout the life of the contract.

b. Utilities shall file with the Commission, beginning six months from the effective date of this order, ~~to the Commission~~ their actual average incremental heat rates and fuel use quarterly, in the case of PG&E and Edison, and three times a year, in the case of SDG&E. The relevant models shall ~~should~~ be modified to make whatever changes are required.

c. Utilities shall use the average annual incremental heat rates, as determined in the most recent rate case, for the derivation of energy prices until the Commission approves refinements.

d. The utilities shall file with the Commission by September 30, 1983 a plan for estimating actual annual incremental heat rates prospectively.

e. Utilities shall propose incremental heat rate revision in Energy Cost Adjustment Clause (ECAC) proceedings after new power plants come on line.

f. PG&E and Edison shall file prospective energy prices quarterly, 30 days prior to the date the prices take effect. Included with the filing ~~should~~ shall be a clear, comprehensive description of how the prices were derived, in order to permit staff and interested parties to comment on them.

g. Absent Commission action, these price offers ~~will~~ shall take effect on the scheduled effective date.

h. SDG&E shall file its energy prices three times a year in parallel with ECAC proceedings. Unless the Commission orders revisions, these prices ~~will~~ shall become effective on the scheduled effective date. SDG&E shall ~~should~~ provide a clear, comprehensive description of how the prices were derived.

i. SDG&E shall use the GN-5 natural gas rate for the determination of its energy prices.

j. Until revised line loss adjustment factors are approved by the Commission, PG&E's, Edison's, and SDG&E's transmission, primary distribution and secondary distribution loss adjustment factors for capacity, and its transmission and primary distribution loss adjustment for energy ~~should~~ shall be set at 1.0. Marginal line losses ~~should~~ shall be used for PG&E's secondary distribution loss adjustment for energy.

k. PG&E shall complete a revised line loss study in cooperation with staff and QF representatives and ~~submit it to~~ file it with the Commission's Executive Director within six months. The study ~~should~~ shall include a methodology for identifying and determining losses from remote sites.

l. SDG&E and Edison shall complete line loss simul~~ations~~ation studies in cooperation with staff and QF representatives within two years and file results with the Commission's Executive Director.

m. Utilities shall include variable operating and maintenance costs in energy prices.

n. Utilities shall permit meters to be fixed on the utility side of a transformer. Transformer loss provisions ~~[illegible]~~ shall be removed from standard contracts if a QF decides to put the meters on the utility side.

o. ~~[illegible]~~, Offers to include 600 hours of curtailment in exchange for a higher energy rate the rest of the time, to levelize energy payments, ~~[illegible]~~ or to adopt floors ~~[illegible]~~ shall be viewed as nonstandard offers at this time, and ~~[illegible]~~ outside the scope of these proceedings. Any such provisions ~~[illegible]~~ shall not be included ~~[illegible]~~ in standard offers. ~~[illegible]~~

p. Utilities shall delete any language which would reduce capacity payments for QFs during periods when they fail to perform under capacity payments due to the utility refusing to purchase from the QF.

q. The Petitions for modification filed by CMA and Imatek, Inc. are dismissed.

r. ~~[illegible]~~ PG&E, Edison and SDG&E shall file studies with the Commission's Executive Director within three months estimating the average and maximum probable application of refusal to purchase and hydro spill provisions in future ~~[illegible]~~ years.

This order is effective today.

Dated at DEC 30 1982, at San Francisco, California.

I will file a concurring opinion.

/s/ LEONARD M. GRIMES, JR.
Commissioner

RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
Commissioners

Commissioner Priscilla C. Grew, being necessarily absent, did not participate