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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983, August 2, 1983, and August 21, 1986)
And Related Matters.	Application 82-04-46 Application 82-04-47 Application 82-03-26 Application 82-03-37 Application 82-03-62 Application 82-03-67 Application 82-03-78 Application 82-04-21

**FOURTH INTERIM OPINION, COMPLIANCE PHASE:
CAPACITY VALUATION; VARIABLE ENERGY PRICING;
STANDARD OFFER 4 MILESTONE, CONTRACT DRAFTING ISSUES**

INDEX

INDEX

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I. Introduction

In Decision (D.) 87-05-060, our first interim compliance phase opinion, we dealt with certain non-resource planning issues in the implementation of final Standard Offer 4. We have since held further hearings in this proceeding in June and July. These hearings concerned resource planning and uniform contract provisions for final Standard Offer 4, and possible reinstatement of Standard Offer 2. In our second interim compliance phase opinion, we found that (1) there are presently no avoidable resources for purposes of final Standard Offer 4, and (2) that Standard Offer 2 should be reinstated for San Diego Gas & Electric Company (SDG&E).

Today's decision, our fourth interim opinion, deals with the two remaining pricing methodology issues for all standard offers and the development of a final Standard Offer 4 contract form with (so far as possible) uniform provisions and terminology for all utilities.

We find that the utilities have generally complied with our direction in D.86-11-071 regarding creation of a reliability target and capacity value adjustment based on Expected Unserved Energy (EUE). We find the resulting Energy Reliability Index (ERI) method should be used by SDG&E and by Southern California Edison Company (Edison) for valuing capacity from any source, including both Qualifying Facility (QF) and non-QF sellers and the utility's own plants and projects. We find the ERI does not yield reasonable results for Pacific Gas and Electric Company (PG&E), and we adopt a temporary capacity value for use by PG&E in 1988.

For QFs receiving variable energy payments, we confirm our conclusion in D.85-07-022 that final Standard Offer 4 QFs on-line in Period 1 of their contracts should have such payments calculated according to the "QFs-in/QFs-out" method. All other QFs receiving variable energy payments should also have such payments calculated according to this method for the time being. However, for the latter QFs, we may shift later to marginal cost pricing (i.e., QFs-in), contingent on various changes in the electricity market and regulatory environment, including possible changes to the Energy Cost Adjustment Clause (ECAC) procedure, so that the benefits of marginal cost pricing flow through to ratepayers.

We approve the uniform final Standard Offer 4 contract provisions jointly sponsored by QF and utility representatives and by Public Staff (renamed the Division of Ratepayer Advocates (DRA) after the close of these hearings). We reject certain alternate provisions proposed by Independent Energy Producers Association (IEP) and by PG&E.

II. Capacity Valuation

We use capacity valuation in many ways, but in this proceeding the chief functions are determining capacity payments to QFs and testing the cost effectiveness of proposed resource additions. All parties agree with the goal that the same capacity valuation method (appropriately differentiated between short-term and long-term) be used for both functions. All parties also agree that the capacity valuation method must be able (1) to measure the utility's relative need for capacity over a given time frame (based on an appropriate reliability target), and (2) to make corresponding adjustments to the utility's capacity payments.

The ERI method that we adopted in D.86-11-071 was intended to satisfy these goals. These goals are compromised somewhat in that the California Energy Commission (CEC) has its own target reserve margins for each utility, using the CEC's reliability model and a target based on a one-day-in-10-years Loss of Load Expectation (LOLE). (The ERI method has a reliability target expressed as EUE and derived by analysis of the utility system in one historical reference year.) Thus, there was confusion in the resource plan hearings on whose target reserve margin was to be used by the utility for purposes of its CEC-based scenario.

Fortunately, the methodological difference does not significantly affect our conclusions at this time on either avoidable resources or capacity payments. As we discuss shortly, the ERI as implemented by SDG&E and Edison yields target reserve margins almost identical to those specified for the respective utilities by the CEC in its current Electricity Report (ER-6). This is not the case for PG&E; however, there do not appear to be any avoidable resources for PG&E even using the EUE target, which PG&E finds to be relatively more stringent (i.e., require higher reserve margins) than LOLE. Thus, we arrive, via a different path, at results that are in fact consistent with ER-6.

There is general agreement that the utilities have complied with the ERI method specified in D.86-11-071. The remaining ERI issues concern input assumptions and updating. The ERI is a way to calculate short-term and long-term capacity values, given the utility's anticipated loads and resources for the forecast period. Long-term capacity values are needed for the standard offers with fixed capacity prices (Standard Offers 2 and 4). Short-term capacity values are needed for the standard offers with variable capacity prices (primarily Standard Offers 1 and 3, plus a few QFs under interim Standard Offer 4). Therefore, input assumptions will affect prices under all the standard offers. Many parties dispute the utilities' assumptions on loads and resources from which ERIs (and ultimately capacity values) are calculated.

A. <u>Nondeferrability and Cost Effectiveness</u>

We will analyze planning assumptions in greater detail in the final decision for the compliance phase. However, one oft-repeated criticism leveled at the resource plan filings deserves immediate comment. The criticism is that Edison and PG&E show many new utility resources coming on-line during the next eight years, despite alleged capacity surpluses, and without a showing of cost effectiveness. (An example is Edison's Big Creek Expansion Project.) Edison responds that the additions are mostly peaking resources, thus nondeferrable by QFs and, in Edison's view, not subject to screening for cost effectiveness.

Edison misreads D.86-07-004.[1] Nondeferrable generation resources don't belong in a resource plan unless they are shown to be cost-effective.[2] To include such resources unfairly reduces capacity payments to QFs and violates least-cost planning principles. Reliance on such a resource plan would limit QF opportunities at ratepayer expense. That is obviously unacceptable.

1 We have a four-part standard for a showing of nondeferrability on a project-specific basis. The showing must: "(1) establish the project's cost-effectiveness, (2) set forth the aspects of the project claimed to justify a finding of nondeferrability, (3) quantify the economic and operational benefits of such aspects, and (4) describe the impact of attempted deferral through the use of 'adders' and standard offer contracts." (D.86-07-004, mimeo., pp. 83-84.) The same decision says that peakers are nondeferrable; however, that generic statement can only be held to cover part (2) of the required showing. There is such a thing as a capital-intensive peaking facility--pumped storage projects such as Edison's Balsam Meadow and PG&E's Helms are examples. These projects may have unique system benefits, but that doesn't excuse the utility from showing that the benefits are worth the costs.

2 Ideally, this statement would also apply to conservation and load-management programs. We are currently undertaking with the CEC and interested parties the modifications to the joint CEC/CPUC Standard Practice Manual needed to ensure that strategies for increasing electrical supply and managing or reducing electrical demand are compared on "a level playing field." See Section I.B.4.a of our Second Interim Opinion - Compliance Phase.

There is an exception to the above generalization on nondeferrability and cost-effectiveness. The exception relates to hydro relicensing. In a petition for modification of D.86-07-004, PG&E has asked that "improvements to hydroelectric projects proposed in the context of relicensing proceedings" at the Federal Energy Regulatory Commission (FERC) be treated as generically nondeferrable. According to PG&E, "[i]f the relicensing improvements are 'avoided' by [a Standard Offer 4] contract, PG&E may be precluded from complying with the Federal Power Act's mandate to develop the resource" and thus "be unable to propose plans giving its customers the best chance to retain these valuable resources."

No party has opposed PG&E's request, and we have decided to grant it. Relicensing improvements are a unique case, in that the failure to pursue the improvement could cause the loss (through denial of relicensing) of an existing resource. Furthermore, the FERC reviews the cost-effectiveness of the proposed improvement. Thus, it is appropriate to treat relicensing improvements as generically unavoidable by QFs. The resource plan of a utility applicant should reflect such anticipated improvements by identifying the projected capacity, output, and operational date of each such improvement, but need not otherwise describe the improvement or justify its cost-effectiveness.

B. ERI Updates

D.88-03-026 has a complete picture of the periodic updating process for the standard offers. We discuss ERI updates now in order to clarify why we are setting some QF capacity payments here and why some will be set in other proceedings.

Standard Offer 2 and final Standard Offer 4 contain long-term fixed prices and accordingly require long-term forecasts. We do such forecasts in our biennial resource plan proceedings, of which this is the first. Thus, the fixed payments in these offers will be set in the resource plan proceeding.

We have previously determined that none of the utilities now has avoidable megawatts for purposes of final Standard Offer 4, and we have also continued the suspension of Standard Offer 2 for PG&E and Edison. Thus, the only long-term fixed prices to be set in today's decision are the capacity price schedules for SDG&E's Standard Offer 2.

Variable capacity payments (for the most part, contracts under Standard Offers 1 or 3) depend on short-term forecasts and should be updated annually. Such payments should not be set in this proceeding, which is biennial and which is largely insensitive to things such as business cycles that may have significant impact for the short term. Our annual ECAC proceedings are ideally suited for such updating because they already require us to adopt assumptions on the utility's loads and resources during the one-year forecast period. ECAC proceedings establish the utility's marginal costs for several purposes; this feature should limit the "gaming" that we fear would occur in a proceeding held only to set short-run QF prices.

Thus, we will update variable capacity payments each year. In the future, this annual update will normally be done in the ECAC proceeding for each utility.[3] Capacity values for SDG&E and Edison will be computed using the ERI method specified in

3 Since this is the first year of the annual update cycle, we must deviate somewhat from our intended reliance on the ECAC proceeding to update variable capacity payments. See the utility-by-utility discussion that follows.

D.86-11-071; for PG&E, we are using a temporary capacity value, described in Section II.E below.[4]

C. Edison

We first reviewed Edison's proposed EUE target in D.86-11-071 and there expressed concerns over its derivation. Edison provided an elaboration in its compliance phase testimony, and we are now satisfied that the proposal, which couples the EUE

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4 Our fourth interim opinion in this proceeding deals with updating generally. However, so that everyone understands that we are not burdening the ECAC proceeding with additional litigation, we briefly summarize now what is involved in the updating of variable capacity payments. The ECAC proceeding already develops a sales forecast and supply assumptions; ERI updating applies a formula (described below) to the adopted ECAC assumptions to come up with the capacity price.

First, an annualized cost of a combustion turbine for the particular utility is needed. This cost is currently set in the utility's general rate case; in the future, it will be updated in the biennial resource plan update proceeding, still using the costing methodology established in D.82-12-120. Second, the utility's latest established combustion turbine cost will be escalated using the previous year's recorded GNP deflator. (See D.87-05-060, mimeo., p. 29.) Third, the ERI is calculated using (1) the load and resource assumptions developed during the ECAC proceeding, and (2) the ERI formula described in D.86-11-071 and applied to the block of QFs receiving variable capacity payments. Fourth and finally, the annualized combustion turbine costs are multiplied by the calculated ERI.

This approach to ERI updating may eliminate an issue from our general rate case proceedings and ensures consistency with the results of our ECAC proceedings without adding issues to the latter.

target with a target reserve margin, is reasonable and should be approved.[5]

Edison's target reserve margin seems consistent with CEC planning criteria. Table 2-13 of ER-6 ("Reserve Margin Assumptions for Key Years") sets the reserve requirement for the Edison planning area at 19.30% in 1990, declining to 17.50% in 1997 and therafter. Edison's target reserve margin is 18 ± 2%. Thus, the CEC's reserve requirement throughout the ER-6 forecast period falls within the narrow band of the target reserve margin that we approve for Edison for use in conjunction with the standard offers.

Under the former capacity price updating procedure, this issue was included in each utility's general rate case. Thus, although the methodological questions for capacity valuation have been in this proceeding, the parties to Edison's current general rate case (Application 86-12-047) have litigated the question of what resources are likely to be available in 1988 for purposes of adjusting Edison's variable capacity payments to QFs. We have therefore set these payments in D.87-12-066, in the general rate case, using the ERI method approved by today's decision. Future updates to Edison's variable capacity payments will be done annually in an Edison ECAC proceeding. Thus, the variable capacity price determined in Application 86-12-047 will continue in effect until a new capacity price is adopted in Edison's 1988 ECAC.

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5 EUE is a probabilistic concept, while the target reserve margin is deterministic but far easier to calculate. Essentially, under D.86-11-071, the utility would always plan to meet its target reserve margin (within a stated tolerance) but would base its capacity payments to QFs on EUE whenever such analysis indicates that higher-than-targeted reserves are needed in order to maintain system reliability at the level derived from the historical reference year.

D. SDG&E

D.86-11-071 reviewed SDG&E's initial EUE proposal and requested certain clarifications and additional conservatism in the choice of a reliability target. SDG&E responded to both requests in its compliance phase testimony. Also, at the request of Santa Fe Geothermal, Inc., Union Oil Company of California, and Freeport-McMoRan Resource Partners (SFG/U/F), SDG&E provided a sensitivity analysis showing the reaction of its ERI to changes in input data. We are satisfied that the proposal (which, like Edison's, couples the EUE target with a target reserve margin) provides a reasonable method for valuing capacity on the SDG&E system.

There is little divergence between CEC planning criteria and SDG&E's target reserve margin. In ER-6, the CEC assumes a capacity reserve requirement for SDG&E of 18.14% in 1990. This declines rapidly to 15.30% in 1992, then declines slowly to 14.23% in 1997, and remains at that level thereafter. SDG&E's target reserve margin is 15 ± 1%. Thus, except for the earliest years, SDG&E and the CEC are very close in their projected reserve requirements for the ER-6 forecast period.

In SDG&E's most recent general rate case (Application 84-12-015), we deferred to this proceeding the issue of capacity values for purposes of all the standard offers. (See D.85-12-108, mimeo., p. 88.) We therefore deal with SDG&E's variable capacity payments in today's decision. Consistent with the discussion in Section II.B above, future updates to SDG&E's variable capacity payments will be done annually in an SDG&E ECAC proceeding.

SDG&E's variable capacity payments are based at this time on the full annualized fixed costs of a combustion turbine. In 1988, such payments should be based on the annualized fixed costs multiplied by SDG&E's ERI for that year. SDG&E must supplement its testimony in one respect in order to perform this calculation: SDG&E's cost for a combustion turbine, shown as $597 per kilowatt

(Exhibit 437), needs to be annualized, using the cost of capital assumptions specified in D.86-07-004.

We have decided, based on SDG&E's near-term need for capacity, to set SDG&E's ERI for 1988 at 1.0. This is a qualitative judgment, but such a judgment is necessary because the record in this proceeding lacks an appropriate short-range forecast (such as we would have in an ECAC proceeding) with which to perform the quantitative analysis specified in D.86-11-071. Therefore, SDG&E's variable capacity prices will continue to be based on an ERI of 1.0 until a revised ERI is adopted in SDG&E's 1988 ECAC.

We have four problems with SDG&E's proposed capacity price tables for reinstated Standard Offer 2. First, pursuant to our second interim opinion, there should be two 50 megawatt blocks, instead of two 100 megawatt blocks as shown in Exhibit 430.[6] Second, the tables need to be completed with capacity price schedules for each year in which the Standard Offer 2 QF is allowed to come on-line, and for all contract lengths to and including 30 years.[7] (The schedules for the second block should assume for each year that all QFs from the first block are on-line.) Third, there was some confusion caused by the column in Tables 7B and 7C (Exhibit 430) with the heading "30 YEAR LEVELIZED PAYMENT 15 YEAR DEFERRAL." Standard Offer 2 QFs, unlike final Standard Offer 4

6 SDG&E endorses this change in its concurrent brief.

7 It appears at present that all of the hurdles to reinstating Standard Offer 2 for SDG&E will be cleared by early 1988. These blocks of Standard Offer 2 megawatts should only be available until the end of calendar year 1988 or until fully subscribed, whichever occurs first. Since the Standard Offer 2 QF has five years after contract signing within which to come on-line, SDG&E must produce capacity price schedules for each year through 1993. In the biennial resource plan proceeding to follow ER-7, we will consider authorizing additional blocks under updated capacity price schedules.

QFs, do not defer or avoid power plants on a megawatt-for-megawatt basis. The capacity payment to be levelized is the fixed cost of a combustion turbine (possibly adjusted in the early years of the contract if the ERI is less than 1.0) for the entire period of the contract, i.e., as much as 30 years. SDG&E witness Mitchell corrected this column on the witness stand; however, we take this opportunity to emphasize this aspect of the relationship between Standard Offer 2 and final Standard Offer 4.

Our fourth problem concerns the additional resources assumed by SDG&E when calculating Standard Offer 2 capacity prices. We agree with IEP that the only resource that SDG&E should add to its resource plan before computing Standard Offer 2 capacity prices is the Silver Gate refurbishment. Had we found avoidable megawatts for purposes of Standard Offer 4, those would have been added to the resource plan and Standard Offer 2 capacity prices computed under the assumption that Standard Offer 4 would be fully subscribed.[8] We did not accept SDG&E's recommendation on avoidable megawatts, however, and consequently there are no Standard Offer 4 resources to augment SDG&E's supply. The refurbishment of Silver Gate, though not avoidable under Standard Offer 4, is cost effective in all of the SDG&E planning scenarios, at estimated fixed costs much less than a combustion turbine. It seems reasonable for a utility needing capacity but not energy (which is SDG&E's situation in at least the early years in the deferral window) to choose the lowest capital cost resource addition (here, Silver Gate) and to add it ahead of more expensive alternatives, including Standard Offer 2 QFs.

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8 As stated in D.86-07-004, "[S]hortage costs for short-run QFs should be computed to assume full subscription of final Standard Offer 4." (Id., p. 71, n. 42.)

Thus, we direct SDG&E to make the above adjustments to its Standard Offer 2 capacity price tables. Also, pursuant to our second interim opinion, we have reviewed comments on queue management and on certain SDG&E proposals for incorporating milestone and curtailment features of final Standard Offer 4 in reinstated Standard Offer 2. (See D.87-12-056.) We are scheduling the filing of these adjustments and amendments to SDG&E's Standard Offer 2 (Application 82-03-78) so that Standard Offer 2 can in fact be reinstated shortly.

E. PG&E

PG&E was the first of the utilities to have a Commission-approved capacity value adjustment.[9] In approving that adjustment, we noted several deficiencies in PG&E's approach. We urged then, and have continued since to urge, that PG&E develop a reliability target based on EUE. PG&E has explored several approaches in the interim, and has also developed an EUE-based ERI that follows our directive in D.86-11-071. We are at long last persuaded that the EUE-based ERI in this form, however suitable it may be for Edison and SDG&E, is not a reasonable way to adjust capacity value on PG&E's system.

The chief reason for our conclusion is that EUE (and apparently other probabilistic measures of reliability) varies exponentially in relation to changes in loads or resources, and that degree of sensitivity seems to us inappropriate for a utility system, such as PG&E's, that is highly dependent on as-available resources such as hydro.

9 This first ERI was adopted in PG&E's test year 1984 general rate case, D.83-12-068 in Application 82-12-48. For the subsequent consideration in the present proceeding of that ERI and other approaches to capacity value adjustment, see D.86-07-004, pp. 27-30, 81, and D.86-11-071, pp. 1-17.

Exhibit 454 illustrates this sensitivity. At the request of the assigned ALJ, PG&E calculated ERIs for 1988 using its existing capacity value adjustment method, which has a target based on Loss of Load Probability (LOLP). Pursuant to that request, PG&E combined assumptions from its current ECAC proceeding with dry and average hydro year data. The results show that under average hydro conditions, PG&E's LOLP-based ERI would be 0.22--in other words, the system would have capacity much in excess of the reliability target. Under dry conditions, the LOLP-based ERI would be 1.11, which says that the system would not meet its reliability target--in other words, it would be capacity-short. An EUE-based ERI would similarly show extreme sensitivity to hydro availability.

The EUE-based ERI developed by PG&E also seems excessively conservative. In D.83-12-068, where we first urged PG&E to develop an EUE target, there is certainly no indication that we intended a more stringent reliability criterion than the one-day-in-10-years LOLP used for the earlier ERI. However, PG&E's implementation of the EUE target described in D.86-11-071 seems to have had that result. According to PG&E (see Exhibit 416), its tables showing annual reserve margins and ERIs with the EUE target imply reserve requirements (to reach an ERI of 1.0) that exceed 30%. In contrast, the reserve requirements implied by PG&E's value-of-service approach are around 20%, and the reserve requirements implied by the former LOLP target (which PG&E feels is itself too stringent) tend to be less than 25%. (Id., pp. B III-11, -12.) We also note that the capacity reserve requirements shown in ER-6 for PG&E appear much lower than those resulting from PG&E's EUE target.[10]

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10 For the Northern California supply planning area, which includes PG&E and the Sacramento Municipal Utility District, ER-6 shows a reserve requirement of 22.60% in 1990, declining to 20.04% in 1997 and thereafter.

PG&E has many other criticisms of the EUE approach described in D.86-11-071. Some of these criticisms are generic to the approach, while others are specific to PG&E's circumstances. We agree with PG&E that there is a degree of arbitrariness and subjectivity in the approach's reliance on one historical reference year; however, some subjectivity inheres in any reliability target that we know of. For example, as PG&E witness Poland candidly acknowledges, PG&E's value-of-service approach (compared to EUE, LOLP, et al.) makes some kinds of subjective judgments unnecessary but requires other kinds of subjective judgments. This record doesn't enable us to determine that one approach is more subjective than another, or that the more subjective approach thereby has less validity.

On the other hand, we agree with PG&E that the interaction of various conservatisms in our EUE approach seems to produce unreasonable results in this case. We would expect that PG&E, because of its size and the importance of weather-dependent resources to its system, would have relatively higher reserve requirements than SDG&E or even Edison. This expectation is consistent with the CEC's projected capacity requirements for the respective systems in ER-6. Nevertheless, the EUE approach implies very much higher reserve margins for PG&E than what we have previously found prudent or necessary. We will not adopt such higher reserve margins without thinking through their implications for system bypass and the ultimate question of how much reliability are PG&E's customers willing to pay for.[11]

11 PG&E has obviously made a good-faith effort to comply with our direction in D.86-11-071 to develop this EUE approach. The fact that PG&E made such an effort, and that PG&E has provided a scholarly and dispassionate critique of the approach, also incline us to give weight to PG&E's objections.

Since we do not reinstate Standard Offer 2 for PG&E at this time, we need not adopt a long-term capacity price table for PG&E in today's decision. However, we must address as-available capacity prices for 1988. We think the most supportable action on this record is to continue in effect the 1987 price ($42 per kilowatt) which already reflects a substantial discount (based on last year's ERI of 0.62) from the full annualized fixed costs of a combustion turbine.[12]

For future adjustments to PG&E's variable capacity payments, we invite comment on the following proposal. We would make such adjustments based on DRA's target reserve margin proposal from Phase II of this proceeding, with slight modifications. The target reserve margin would be taken from the CEC's most recent ER. The ERI would have a ceiling of 1.0 and a floor of 0.4. The ceiling price would be paid whenever the projected reserve margin for the forecast year (as determined in a PG&E ECAC proceeding) would be equal to or less than the target. The ERI would decline linearly until the projected reserve margin is six percentage

12 Since we are continuing the 1987 capacity payment without inflation adjustment, the implicit ERI is slightly lower than that in effect for 1987. The result seems at least qualitatively consistent with PG&E's current circumstances. The 1987 ERI derives from PG&E's LOLP-based capacity value adjustment that we approved in D.83-12-068. We know that that ERI was predicated on a very low projection of QFs coming on-line. On the other hand, both D.83-12-068 and Exhibit 454 in the present proceeding suggest that PG&E's 1988 ERI might be higher than in 1987 rather than lower. The dim prospects for return to service of Rancho Seco also suggest that any marked decline in PG&E's ERI for next year is unwarranted.

points over the target; at or beyond that point, PG&E would pay the floor price for as-available capacity.[13]

We recognize that in a wet year, and in many average years, the floor price will result in modest capacity overpayments to as-available QFs; however, as Exhibit 454 shows, the ceiling price will result in capacity underpayments in virtually any dry year, no matter how large the apparent capacity surplus on PG&E's system. This seems to be a reasonably balanced approach to adjusting variable capacity payments on a utility system where hydro plays such an important part.

PG&E's comments on the proposed decision say that the CEC's target reserve margins (based on a long-term methodology) may not be appropriate for calculating near-term ERIs. According to PG&E, the impact of uncertainty increases over time for various factors, such as load growth. These factors increase target reserve margins from a long-term planning perspective. Assuming that this is so, we think that there may be countervailing factors, such as weather, that tend to normalize over the long-term but greatly affect short-term needs. However, we will provide for further comment on this and other aspects of our proposal.

The above proposal is not intended for long-term planning purposes. However, as PG&E has noted, PG&E's own thermal power plant projects receive certification from the CEC based on conformity with the CEC's projected capacity requirements from the most recent ER. We think that the resource planning criteria applied by the various regulatory agencies should be reasonably

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13 This formula would also apply to those few interim Standard Offer 4 QFs that receive variable capacity payments.

The suggested floor price derives from the cost of refurbishing a combustion turbine (as indicated by SDG&E's data for Silver Gate) compared to the cost of constructing a new one.

consistent, and since we have rejected the EUE-based ERI for PG&E, it seems logical that we use the current CEC criteria in our own proceedings whenever capacity planning on PG&E's system is at issue.

To summarize, we will use EUE-based ERIs for SDG&E and Edison, and CEC-based target reserve margins for PG&E, in our capacity planning approach for the respective utilities. The only issue that remains open is the short-term capacity value adjustment for PG&E. After taking comments on our floor/ceiling proposal, we hope to adopt an adjustment method in the final decision of this compliance phase.

F. <u>Reliability Models and Value-of-Service</u>

The record of the resource plan hearings shows the growing importance of reliability models in CPUC proceedings. The number of such models, and the CEC's reliance on MAREL, makes it desirable for us to increase our understanding of them. We should know how such models are calibrated and how they differ from (or are similar to) the production cost models with which we are more familiar.

Also, the EUEs calculated by the utilities seem anomalous when compared with each other. Specifically, PG&E's and SDG&E's EUEs bear roughly the same proportion as their respective peak demands. This seems logical. Edison's EUE calculations, on the other hand, are proportionally much lower than PG&E's or SDG&E's. This does <u>not</u> affect the validity of the reliability targets or the ERI. As SDG&E points out, there are many reliability models, using different methods to calculate EUE; what matters is (1) the internal consistency of a given model, and (2) the consistent use of a single reliability model by each utility. Still, it is puzzling that the absolute value of the EUEs calculated by different models seems to vary by an order of magnitude.

Pursuant to Assembly Bill 475 (Moore, Chapter 1297 of the 1985 Statutes), we investigated and have prepared a report to the

California Legislature on computer models used in our proceedings. We are also developing rules for public access to such models under that law. Our ongoing study of computer models is the appropriate setting to develop information on reliability models. DRA should evaluate the reliability models used by the parties in this proceeding and include its findings in future reports prepared pursuant to Assembly Bill 475. This evaluation should include a description and comparison of the various models and how they are calibrated, and should recommend any appropriate modeling conventions to be used in future proceedings.

Finally, both the CPUC and the CEC are committed to improving our analyses of reliability and capacity valuation. For example, the CEC is investigating potential refinements to MAREL, and both commissions have noted with interest PG&E's ground-breaking analysis of the value-of-service approach to capacity valuation. We believe that approach has potential advantages over traditional measures. Whether (and when) that approach can be substituted for traditional measures is another question. DRA, in coordination with CEC staff, should hold a workshop, probably after our final compliance phase decision, to determine what are the utility plans in this area, and to develop a consensus on goals and priorities.

G. <u>Ramped Payment Stream</u>

The Energy Consulting Group (ECG) raises a final Standard Offer 4 implementation issue that implicates capacity valuation, cost-effectiveness analysis, and calculation of the fixed (or capital) costs of the deferred resource.

One part of the payments that the final Standard Offer 4 QF receives is based on the fixed costs of the deferred resource on an annualized basis. This part is established in "real" terms (discounted by the result of the second price auction if the offer is oversubscribed) at the time the QF enters into its contract. This part is also adjusted ("ramped") according to actual inflation during the contract. The ramped payment stream provides substantial price certainty to QFs but avoids the risks of front-loaded payments and keeps all parties indifferent as to the impact of inflation. We derive the ramped payment stream using the so-called "deferral method" (see D.87-05-060, mimeo., pp. 28-29).

ECG questions the implementation of the deferral method as proposed by the utilities. ECG says that the utilities ignore the tax deductibility of interest expense, which results in a discount rate which is too high by about 1.8% and thus overstates the ramped capital costs. According to ECG, the utility implementation (1) delays the apparent cost-effectiveness of baseload and intermediate plants, and (2) causes ratepayers to overpay capital costs by about 4% each year.

Edison's rebuttal is succinct. ECG, according to Edison witness Jurewitz, "fails to recognize that the income tax component of utility revenue requirements already incorporates the interest expense deduction. Thus, the incremental cost of capital calculated by Edison represents the return on investment required by investors, already taking into account the tax deductibility of interest expense." (Exhibit 424, p. II-13.)

We agree with Edison that the tax deductibility of interest expense is considered in determining utility revenue requirements. Furthermore, the utilities appear to have used formulas here that are consistent with present practice for calculating revenue requirements. It seems from the prepared testimony and cross-examination that the question is not whether but how the tax deductibility of interest expense is to be accounted for. However, ECG also has a point in that the method used for factoring certain fractions into the formula can affect the bottom line.

For present purposes, i.e., determining avoided cost payments for deferring/avoiding a utility resource, we approve the implementation of ramped payment streams as proposed in the utilities' compliance filings. This is because these filings are consistent with the derivation of the utilities' own revenue requirements and thus preserve ratepayer indifference as between QFs deferring a given resource and the utility acquiring it.[14]

III. Energy Pricing for QFs with Variable Energy Payments

One of the main issues in the consolidated standard offer proceeding concerns the calculation of energy prices for QFs whose contracts provide for variable energy payments.[15] Such QFs are primarily on the short-run standard offers (Standard Offers 1, 2, and 3) but also include interim Standard Offer 4 QFs at the end of

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14 Our conclusion here does not preclude a separate investigation of the treatment of taxes in calculating utility revenue requirements. We recognize the importance of this subject, but it is beyond the scope of the present proceeding.

15 "Variable energy payments" are those that we recalculate periodically, on a prospective basis during the contract term, based on our latest projections of the price of the marginal fuel and of the incremental energy rate (IER) for each utility. (The IER reflects the utility's use of thermal energy in producing electricity at the margin; generally, the marginal unit of electricity is generated by burning oil or gas, but the CPUC's energy pricing method also recognizes periods when, e.g., non-oil/gas fuels or power purchases are on the margin, and reduces the utility's IER accordingly.) Marginal fuel prices have been updated quarterly since the beginning of our QF program. In our fourth interim compliance phase opinion, we adopt a new updating procedure that continues the quarterly revision of marginal fuel prices and institutes an annual revision of the IERs.

Some QFs (e.g., final Standard Offer 4 QFs during Period 2, interim Standard Offer 4 QFs early in their contracts) receive "fixed energy payments." By this term, we mean simply that at least the IER used to calculate such a QF's energy payments is established by contract for some period longer than the update cycle we use for recalculating the bases for variable energy payments.

the fixed price period, certain QFs under nonstandard contracts, and final Standard Offer 4 QFs that come on-line during Period 1 (i.e., before the on-line date of the deferred resource). We conclude that the calculation method known as "QFs-in/QFs-out," which we have previously approved for final Standard Offer 4 QFs during Period 1 (D.85-07-022), and for pricing short-run QFs on the SDG&E and PG&E systems, should be used at this time for all utilities and all QFs receiving variable energy payments. However, we reject arguments that QFs-in/QFs-out is absolutely required by federal law.

A. The Basics of QF Energy Payments

All parties would use the same basic components to calculate variable energy payments to QFs; what is under debate here is the derivation of one of the components, the IER.

Under all of the various QF contracts that we mentioned above, the QF gets paid on a cents per kilowatt-hour basis for energy that it generates and delivers to the grid. The payment essentially results from a two-part formula. One part is the purchasing utility's IER, which is its incremental efficiency in converting heat energy to electricity and which is expressed as British thermal units (BTUs) per kilowatt-hour. The other part is the cost of the purchasing utility's marginal fuel, typically oil or gas. This part is expressed as dollars per million BTUs. Multiplying the IER by the fuel cost gives the cents per kilowatt-hour that the purchasing utility pays for the QF's output.[16]

16 The cents per kilowatt-hour figure is then time-differentiated to reflect the purchasing utility's variation in marginal running costs at different times of day and seasons of the year. Time-differentiation serves to give accurate price signals to QFs and to maintain ratepayer neutrality in having energy generated by the QF rather than by the utility.

The formula worked quite smoothly for the first few years of the QF program. Currently, there is controversy that affects both parts of the formula due to recent changes in circumstances. The calculation of marginal fuel cost is complicated by major changes in CPUC gas rate design policies set in motion by D.86-12-009. We are now completing the implementation of that decision and have held hearings on the issue of gas costs avoidable by QFs.

The calculation of incremental efficiency was also easy as long as QFs were a very small part of a utility's resource mix: if QFs account for relatively few kilowatt-hours, all parties agree that the generation efficiency of the last kilowatt-hour dispatched from the utility's own resources is a reasonable approximation of what the utility would do in the QFs' absence. The problem that we address here is how to calculate the IER when (as is now the case) QF output is much greater, both proportionally and in absolute terms, so that QFs in effect back down many <u>different</u> utility resources, with potentially many different efficiencies.

B. <u>Computer Runs and Variable Energy Payments</u>

Our discussion uses the terms "QFs-in" and "QFs-out" to describe two kinds of computer runs that represent the operating efficiency of any given utility system by means of a production cost simulation model. As their names suggest, the only difference between the two runs is in the treatment of QFs. The QFs-out run represents the projected dispatch of the system with all variably-priced QFs removed. The QFs-in run represents system dispatch including all variably-priced QFs anticipated to be on-line during the forecast period. Finally, the term "QFs-in/QFs-out" refers to the average of the IERs calculated by performing the two runs for a given utility system.

C. <u>Arguments for QFs-in (Marginal Cost Pricing)</u>

As QFs are added to a utility's system, that utility is able to turn off its less efficient, higher running-cost plants an increasing proportion of the time. In other words, the utility's IER drops. The present debate concerns what IER to use in calculating variable energy payments: an IER representing the utility's efficiency for the last unit of electricity actually dispatched (QFs-in); or an IER representing the utility's average efficiency in replacing QF power--i.e., the utility's avoided cost measured over the whole block of short-run QF output--if the utility itself had to generate the electricity delivered to its system by these QFs (QFs-in/QFs-out).

PG&E and Edison support the QFs-in approach.[17] They say that QFs-in more closely simulates a competitive "spot" market price. They note that, as the number of short-run QFs selling to a particular utility grows, the difference between the QFs-in and the QFs-in/QFs-out IERs grows proportionally, and they claim that using QFs-in results in lower costs to ratepayers. Finally, they believe that QFs-in correctly interprets the directive in federal regulations that sales of QF energy be priced at the purchasing utility's avoided costs.

These utilities also caution that under certain circumstances, QFs-in/QFs-out does not realistically reflect what a

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17 However, PG&E and Edison use different methods to calculate the QFs-in IER. PG&E seems to have in mind its instantaneous marginal rate, which appears to be equivalent to what some parties refer to as "system lambda." Edison uses a "zero-intercept" calculation that accounts for certain start-up and other operational costs resulting from a change in loads and not reflected in system lambda. The consensus of commenters is that Edison's method, compared to PG&E's, is less sensitive to minor variations in assumptions, and PG&E has indicated that it is willing to consider the method for its own use. We do not adopt a QFs-in method at this time; however, the advantages of the zero-intercept calculation seem clear. PG&E should be prepared to explain any reason for not adopting that calculation at such time as we revisit the variable energy payment issue.

utility would have done to replace short-run QF power. The potential distortion occurs because QFs-in/QFs-out is predicated on dispatch of the utility's existing system; however, at some point, consistent with prudent long-run planning, the utility would add a new, more efficient resource (resulting in a lower IER than that suggested by QFs-in/QFs-out) rather than just running its existing system harder. The likelihood of such distortion increases with the number of short-run QFs. PG&E and Edison concede that the refinements to QFs-in/QFs-out proposed by DRA and by SFG/U/F might mitigate this problem, but they believe that the refinements (1) are hard to implement, and (2) do not provide the advantages claimed for the QFs-in method.

D. Arguments for QFs-in/QFs-out (Incremental Cost Pricing)

DRA and QF representatives say that short-run QFs are entitled under federal law to be paid for energy according to the costs that a utility would have incurred "but for" the energy delivered by these QFs. The QFs-in/QFs-out IER calculation accurately measures such costs. QFs-in allegedly undervalues short-run QFs because the utility can recover its full cost of replacing QF deliveries, should these fall short of the quantity estimated for purposes of calculating the QFs-in IER. Thus, the benefits claimed for ratepayers under QFs-in are illusory.

DRA and QF representatives note that the electric utility continues to occupy an essentially monopsonistic position in this market. They believe that QFs-in, rather than promoting competition, strengthens the utility monopsony because only the QFs have to compete at the QFs-in price, while the utility in case of need can dispatch less efficient resources and still recover its excess costs through ECAC.

SFG/U/F (supported by IEP) and DRA believe that QFs-in/QFs-out does not appropriately price short-run QFs' energy deliveries under all circumstances. At some point, a utility will incur energy-related capital costs to add a new resource (in order to lower its operating costs) rather than run its existing system harder. These parties would all modify the QFs-in/QFs-out method to provide a cap on variable energy prices whenever a utility has so many short-run QFs on its system that it would substitute a new resource to lower its operating costs if all these QFs were removed from its resource plan.

These parties present two different proposals for identifying "substitute" resources. However, the purpose of the proposals is identical: to arrive at a continuously optimized resource plan for each utility, such that short-run QFs in each year receive energy prices that reflect an optimal mix of existing and "substitute" resources, based on the latest Commission-adopted planning assumptions.[18] As these parties note, such optimization is possible for a utility only by virtue of having QFs on its system.

SDG&E generally supports using the QFs-in/QFs-out method but also believes that the method could give improper price signals if large amounts of QF power are being purchased. That is not presently the case for SDG&E's system, and SDG&E recommends that the method not be modified until an actual situation illustrates why modification is warranted.

18 "Avoidable" resources are those that a utility would add with all its existing resources shown in its resource plan; "substitute" resources are those that a utility would add with short-run QFs removed from its resource plan. If an avoidable resource is identified, it becomes the basis of a final Standard Offer 4 auction and may be built if not deferred through the auction; if a substitute resource is identified, it would not be built but becomes the basis for limiting energy prices paid to short-run QFs. Essentially, substitute resources are a device for ensuring that the presence of a large number of short-run QFs in a utility's resource mix does not result in the uneconomic displacement of attractive long-run resources.

E. Discussion

1. Final Standard Offer 4 QFs in Period 1

Final Standard Offer 4 QFs are allowed to come on-line in Period 1, i.e., before the projected on-line date of the utility resource that such QFs defer or avoid. During Period 1, such QFs are not paid based on the deferrable resource but instead are to receive capacity payments based on the purchasing utility's then-current shortage costs and energy payments based on the QFs-in/QFs-out method. (See D.85-07-022, mimeo., pp. 54-56.)

The debate in the compliance phase is not over the propriety of this treatment of final Standard Offer 4 QFs during Period 1, but rather whether the treatment should be extended to include all QFs receiving variable energy payments, as D.85-07-022 and D.86-07-004 (see pp. 77-78) suggest. In today's decision, we adopt a more qualified endorsement of the QFs-in/QFs-out method of short-run energy pricing, so it is important to make clear that, regardless of the pricing method for other QFs receiving variable energy payments, QFs-in/QFs-out remains appropriate for final Standard Offer 4 QFs in Period 1.

The reason for this distinction is that even in Period 1, a utility system has increasing operating costs that will eventually justify a commitment of capital (so-called "energy-related capital costs") to improve system efficiency. Final Standard Offer 4 QFs, but not others, are specifically designated to defer or avoid investments with energy-related capital costs; the payment stream to final Standard Offer 4 QFs in Period 1 should therefore reflect the cost characteristics of the utility system that are projected to justify the addition of the deferrable resource at the start of Period 2. This is exactly what the QFs-in/QFs-out method does.

2. Substitute Resources

Everyone now accepts the premises (1) that a prudent utility would not continuously add short-run QFs, or other short-run resources, and thus (2) that the QFs-in/QFs-out method could at some point produce unrealistic results because it relies on modeling the dispatch of the utility's existing system. In theory, the method should therefore be modified to somehow account for any long-run resources that a utility would substitute for short-run QFs if they were all removed from its system.

For now, we will not adopt either SFG/U/F's or DRA's suggested modifications. There are at least three reasons for this decision.

First and most important, short-run QFs, although their absolute numbers have increased enormously since the start of the QF program, are still a very small part of the utilities' resource mix. No party has said that substitute resources would be found now if the utilities were to conduct a resource plan analysis of their QFs-out runs; and several parties, such as SFG/U/F and the California Cogeneration Council, have testified that the problem is likely to remain entirely theoretical at least until the late 1990s, when large numbers of interim Standard Offer 4 QFs reach the end of the fixed energy price periods in their contracts. The record seems to support these parties.

Second, both of the suggested modifications involve fairly complex and hypothetical manipulations of utility resource plans. We agree with SDG&E that it is wise to gain more experience with the biennial resource planning process before making new demands on that process.

Third, as we discuss below, we may change the basis for calculating variable energy payments to QFs other than final Standard Offer 4 QFs in Period 1, depending on possible changes to the ECAC balancing account procedure and further evolution of the electricity market such that the utilities and QFs compete on a more even footing. Thus, the need to modify the QFs-in/QFs-out method may never arise.

3. Marginal vs. Incremental Cost Energy Pricing

This brings us to the heart of the matter. Specifically, we must decide on the method of calculating variable (short-run) energy payments that is consistent with our current regulatory policies and with state and federal laws and regulations on avoided cost pricing.[19]

As we interpret this body of law and policy, the purpose is to create a pricing structure that captures to the extent possible the efficiency and other benefits of perfect competition in electricity generation.[20] It seems logical under such conditions that a buyer (whether for the buyer's own use or for resale) would purchase electricity offered at a price that is lower than the buyer's own cost to generate an equivalent amount of electricity. Also, the buyer would continue to make purchases up to the price at which it could otherwise get the offered electricity at the same or lower cost. Everybody benefits: the buyer(s) by minimizing costs, the seller(s) by generating at a profit, and society at large by efficiently allocating its resources. Unfortunately, neither QFs-in nor QFs-in/QFs-out will fully capture these benefits under existing conditions.

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19 The federal Public Utility Regulatory Policies Act (PURPA) and the California Private Energy Producers Act supply the statutory context for the development of avoided cost pricing. Also, the Federal Energy Regulatory Commission has adopted regulations implementing PURPA (FERC regulations), and all of these authorities have been interpreted in the extensive body of CPUC decisions on QF matters. (See generally D.86-07-004 and the decisions cited in Appendix C of that decision.)

20 We emphasize "perfect" competition because we doubt that many markets in fact behave as theory predicts, and because state and federal law do no more than loosely approximate a competitive market in electricity: for example, the QF generally has few if any buyers for its electricity other than the utility in whose service area the QF is situated.

QFs-in/QFs-out does not give an accurate price signal as to the value of additional energy deliveries by QFs. The method prices short-term energy based on the utility's average cost to replace projected QF deliveries through other generation resources available to the utility. As such, the method truly represents the value to the utility of the increment of QF deliveries projected for the forecast period. However, the last generation resource backed down is likely to be cheaper than that average cost, so the utility may be required in some circumstances to pay a price to QFs that it would not pay in a true "spot" market because the utility would prefer to run its own plant.[21]

The problems with QFs-in are worse. While QFs-in/QFs-out gives an inaccurate signal on the value of additional energy deliveries by QFs, QFs-in prices all short-run energy deliveries as if the utility could replace such deliveries at its so-called marginal cost. There are at least four powerful objections to this.

First, if the projection of loads and resources for the forecast period is otherwise accurate, the utility would not be able to replace a shortfall in QF energy deliveries at a cost less than or equal to the QFs-in price. Depending on the timing of that shortfall, the utility might have to dispatch plants significantly more expensive than the running costs of the marginal resource in the QFs-in run.

21 Whether the result would be overpayments or underpayments to QFs is less clear. If QF deliveries for the forecast period are less than projected, then QFs receiving variable energy payments would actually be underpaid. The problem is that QFs deciding whether to develop new short-run projects or increase deliveries from existing short-run projects would be making their decision based on an average avoided cost, not a marginal cost. Oil and gas prices are currently very low, so the practical impact of this distortion may be slight; the impact is likely to increase proportionally as fuel prices rise.

Second, the utility does not have to absorb the increased energy costs just described. Those costs are picked up almost entirely by the utility's ratepayers. This is because the ECAC balancing account presently flows through to ratepayers almost all of the utility's energy costs in excess of those forecast, subject only to reasonableness review.[22]

Third, because of the factors we have just noted, QFs-in gives the utility an enormously powerful tool with which to exploit its typical position as primary or sole purchaser of a QF's electricity. Under QFs-in pricing, a utility could pursue a deliberate policy of getting rid of QFs simply by forecasting excessive QF deliveries, thus depressing the IER on which the energy price is based.[23] ECAC insulates such a utility from the economic consequences of such a policy; furthermore, unlike weather-related uncertainty, there is no assurance that forecast error resulting from bias will cancel out over time.[24]

Fourth, we don't think that QFs-in equates to marginal cost pricing, even though PG&E and Edison say it does, and though we ourselves have referred to it as such for convenience. Fundamentally, QFs-in identifies the last kilowatt-hour dispatched

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22 The only qualification to this generalization is that the utility is at risk for a portion of its energy costs by virtue of the Annual Energy Rate. This rate varies among the utilities but in each case represents a small fraction of the expenses subject to balancing account treatment.

23 The utility has a similar incentive under QFs-in/QFs-out but not nearly to the same degree because the averaging of IERs dilutes the impact of erroneous forecasts.

24 Without PURPA and the other legal requirements cited earlier, a utility could refuse to purchase QFs' deliveries or prefer its own more expensive generation only at some economic risk to itself. Thus, in some ways, the interaction of ECAC with QFs-in enables the utility to wield its market power over QFs even more effectively than it could before the passage of PURPA.

from non-QF resources on a utility system under a given set of load and resource assumptions. That last kilowatt-hour could be generated at a cost equal to or higher or lower than the utility's marginal cost as determined in a competitive market. Nobody knows which, because the electricity market is far from perfect.[25] A competitive market is characterized by many buyers and sellers, many types of purchase contracts (some of them for terms of days or even hours), and most importantly, price-based decisions to produce or to purchase a particular good. In particular, the economically rational buyer in a competitive market will maximize the buyer's wealth by making all attractively priced purchases, and would lose wealth by foregoing such purchases. None of these conditions now exists in the electricity market generally or for the utility buyer of QF power. In fact, as ECAC presently works, some degree of market failure is institutionalized.

Thus, while conceding that good arguments support QFs-in as the basis for variable energy payments, we think that QFs-in/QFs-out is clearly preferable given the current industry structure.

4. Consistency with PURPA

PURPA and the FERC regulations generally require that the rate paid by a utility for QF power equal the utility's avoided costs. These are defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." (18 CFR §292.101(b)(6).) In determining avoided costs,

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25 Furthermore, it is only in the long-run equilibrium state of a perfectly competitive industry that the cost of producing the last unit of output would equal the price paid by consumers for that unit. In contrast, utility electric rates to end-users are based on average system costs.

the state regulatory authority is required to consider numerous factors as well as data provided by the utility. (18 CFR §292.304(e).)

We think that PURPA and the FERC regulations give the states some latitude to determine avoided costs; in other words, there is no neat formula for calculating avoided costs. The touchstone is always that the rates for utility purchases (1) be "just and reasonable to the electric consumers of the electric utility and in the public interest" and (2) "not discriminate against [QFs]." (See PURPA §210(b), emphasis added.)

The QFs-in/QFs-out method for calculating short-run energy prices seems consistent with the PURPA avoided costs standard. The method determines a price for an increment of QF deliveries, and FERC defines avoided costs as incremental, not marginal. Also, given our ECAC procedure, QFs-in/QFs-out truly reflects the costs that ratepayers see "but for" deliveries from short-run QFs.

However, it does not follow that federal law precludes the QFs-in method. We believe the state regulatory authority has the ability under PURPA to take into consideration the kinds of factors that we analyzed in Section III.D.3 above and to reach a different conclusion on avoided costs when conditions in the electric industry change.

PURPA was passed primarily to counteract electric utilities' exploitation of their market power to restrict development of potential electric generation by non-utility entrepreneurs. That purpose would be thwarted by having QF output priced at a so-called marginal cost that the purchasing utility did not have to meet or beat. Correspondingly, if ECAC were changed such that the purchasing utility were at risk in making up for any shortfall in QF deliveries at the utility's stated marginal cost, then it might very well be appropriate in a subsequent biennial update to revisit the question of QFs-in as the basis for variable energy payments.

Changes to ECAC, of course, should be considered in an ECAC proceeding or in a generic rulemaking to revise electric utility ratemaking mechanisms similar to R.86-10-001. Furthermore, we cannot specify in advance the kinds of changes necessary in order to put the utility "at risk." We would have to weigh proposed changes carefully to ensure that they are consistent with our overall policies as well as with the QF program. On the other hand, the utilities themselves have indicated a desire to position themselves competitively to respond to problems such as uneconomic bypass; to the extent that ECAC flows through automatically some amount of fuel expense that is susceptible to management control, ECAC contributes to the bypass problem, and the utilities might actually be better off by foregoing such balancing account treatment.

In short, the QFs-in/QFs-out method meets the PURPA requirements for QF pricing. To the extent that changes in ECAC and possibly other developments create a more competitive environment and move this industry closer to a true spot market, it is appropriate and consistent with PURPA to reconsider marginal energy cost pricing for short-run QFs. Such reconsideration would take place only in the biennial resource plan proceeding, which is the appropriate forum for dealing with standard offer methodological issues.

IV. Standard Offer 4 Milestone, Contract Drafting Issues

A primary function of the standard offers is to reduce the transaction costs of creating power purchase agreements between utilities and QFs. By previously approving the terms and conditions of standardized contracts, the Commission speeds the process, helps to ensure its fairness, and enables QF and utility negotiators to focus on those areas where nonstandard provisions may benefit both parties to the agreement.

The development of final Standard Offer 4 provides many challenges and opportunities for contract drafting. Final Standard Offer 4 has many unique provisions and requires adaptations to the QF Milestone Procedure. Also, the QF Milestone Procedure was created outside of the standard offer development process, and so the procedure has existed as a separate document from the power purchase agreements that it governs. This anomaly could be corrected for final Standard Offer 4 by incorporating the procedure in the contract form.

Another important goal is to achieve the highest possible degree of uniformity between the contract forms and terminology of the different utilities. This would ensure evenhanded treatment of QFs throughout the state, while allowing such variation as might be compelled by the particular circumstances of individual utilities.[26]

The Commission has felt that all of these goals could be advanced through consultation among the parties in an informal setting, leaving fewer disputed areas for adjudication. The parties bring to such consultation an impressive range of expertise and experience with existing power purchase agreements. Discussions among these parties seems both preferable to weeks of

26 Workshops were held earlier in this proceeding to develop uniform contract language for the other standard offers. One of our tasks following the final compliance phase decision is to review the agreements from these workshops for possible CPUC approval. As we discuss in Section II.C.2 of the second interim opinion in this phase, some of the products of the final Standard Offer 4 contract drafting may also be appropriate for other standard offers; ordering paragraph 5 of that decision solicits comment on this point.

hearings and likelier to produce technically sound solutions that everybody could live with.

A. <u>Summary of the Negotiations</u>

The task was enormous. We cannot discuss the finished product of this contract drafting effort without first acknowledging and expressing our appreciation for the work that went into it.

D.86-07-004, ordering paragraph 1.b, directs the utility applicants to amend their applications to include final Standard Offer 4 contract forms; making maximum use where feasible of provisions from the other standard offers.

On October 31, 1986, the utilities served their compliance filings, including proposed contract forms. On November 21, 1986, SFG/U/F served rebuttal testimony that contested many utility-proposed provisions and included its own proposed contract form. IEP supported SFG/U/F's rebuttal testimony.

At hearings on non-resource planning issues held in December 1986, the ALJ urged the parties to hold workshops to try to resolve the areas of dispute or at least to reduce the number of issues for hearings starting in June 1987. The utility applicants, DRA, IEP, and SFG/U/F held workshops from early January on, for a total of 18 days during the next five months. Also, SFG/U/F and Edison met for several more days during this period to draft language as areas of agreement were reached. At the end of May, workshops had resulted in agreement on a uniform final Standard Offer 4 contract as to all but 10 areas of disagreement and two areas (curtailment and power sales at the end of Period 2) on which discussions were deferred due to time constraints.

On May 29 and June 1, 1987, the parties served testimony on the areas of disagreement. Also, PG&E served testimony on five areas for which it sought utility-specific variations from the agreed-on provisions.

On the first day of the June hearings, the parties suggested that further workshops might resolve some remaining areas of disagreement. The ALJ authorized workshops to continue, and the parties met for four more days, ending July 2, 1987. There was one more meeting between SFG/U/F and Edison to finalize contract language on areas of agreement.

At this point, the parties to the workshops (other than PG&E and IEP) had achieved agreement on all issues. The Joint Testimony served on July 10, 1987, sets forth the agreement among the parties and identifies areas that remain disputed by PG&E and IEP. (PG&E still has four objections, while IEP has one.) The Joint Testimony presents a complete final Standard Offer 4 contract form for the Commission's review.

B. Contract Provisions of Final Standard Offer 4

As summarized in the Joint Testimony (Exhibit 447), the parties have followed the Commission's directive to use, where possible, provisions previously approved for use in other standard offers. Thus, the parties based their agreements on the uniform version of interim Standard Offer 4, with appropriate changes to account for the different basis for calculating avoided cost in final Standard Offer 4. The parties have also incorporated new provisions such as Project Development Milestones (thus avoiding the potential confusion resulting from a discrete QF Milestone Procedure not contained within the four corners of the contract), Abandonment, Power Sales at End of Period 2, and liquidated damages.

The Joint Testimony explains that, where the parties have modified previously existing standard offer contract provisions and added new provisions, they did so to accommodate the differing nature of final Standard Offer 4. They say (and we agree) that the latter offer involves both a greater degree of discipline in the obligations of the QF, especially in development stages, and a greater degree of utility cooperation with the QF. Thus, the contract generally reflects a high level of commmunication and information between the utility and the QF, and a balancing of rigorous development milestone requirements with appropriate flexibility and reduced development risk.

Generally, the parties also stress that the agreed-on provisions represent a whole series of compromises and tradeoffs to reach a balanced, equitable agreement. On that basis, the parties "cannot emphasize too strongly that deviations in one or more isolated positions will tend to upset that balance and likely yield an agreement which is not evenhanded and on which agreement could not have been reached." (Exhibit 447, p. 2.)[27]

C. <u>A Valediction</u>

The above summary barely hints at the magnitude and the significance of the achievement marked by the Joint Testimony. Final Standard Offer 4 is the most ambitious standard offer we have ever attempted. Something of this is suggested by the sheer size of the contract form, which runs to over 100 pages plus appendixes. Much more impressive is the effort involved in giving linguistic expression to complex formulas. The parties have not only met this challenge, but have produced a document that is easy to follow and even, with allowances for the technical nature of the subject, easy to understand.

No contract form can be so meticulous as to wholly forestall later disputes on the meaning of the agreement, particularly in a case like this, where the subject of the agreement is complex and the economic stakes are high. Nevertheless, this joint effort has brought to bear a wealth of

27 In deference to this view, IEP did not sponsor the Joint Testimony but has indicated that it takes issue with that testimony in only one respect. PG&E did sponsor the Joint Testimony, although it requests different provisions specific to PG&E in four respects.

experience (some good, some bad) under other standard offers and has fostered a common understanding and an atmosphere of cooperative problem-solving that should result in fewer and more easily resolved disputes.

The mass and detail of the contract form again recall the significance of the standard offer in reducing transaction costs. Negotiating this contract would overwhelm the capabilities of a small QF. We suspect that case-by-case negotiation of such contracts would severely strain even large QFs and the utilities themselves. Even nonstandard power purchase agreements are helped because the parties to such agreements may be able to use most of the standard provisions and thus to concentrate their efforts on project-specific provisions (e.g., additional performance features) that would benefit both seller and utility.

We think that the final Standard Offer 4 contract form is one of the outstanding achievements in the evolution of the QF industry. That the contract form is the product of a cooperative effort of utilities, QFs, and our own staff, marks the further maturation of the QF industry. As we have often said, the full integration of QFs in utilities' resource planning requires that QF/utility discourse occur more often at the bargaining table and less often in our hearing rooms.

For all these reasons, we are delighted with the product of this negotiating effort. All the participants in that effort--Edison, IEP, PG&E, SDG&E, SFG/U/F, and DRA--have earned our thanks and congratulations.

D. <u>Issue Deferred for Later Resolution</u>

One area put at issue in testimony served before the Joint Testimony relates to the capacity factor assumed for the avoidable resource. Some parties would fix this factor for the duration of the contract at the time the resource is identified; other parties would make some provision for updating this factor.

The parties basically ran out of time to deal with this issue. They jointly request that we approve the final Standard Offer 4 contract as presented in the Joint Testimony, while deferring the capacity factor issue to the next round of utility resource plan filings.

This request makes good sense. In the absence of an avoidable resource for any of the utilities at this time, we feel no urgency in addressing this issue. We accordingly defer this issue to the biennial update proceeding. We of course encourage the parties to discuss the issue before that proceeding, and to present any negotiated resolution for our consideration at that time.

E. Agreement in Principle on Curtailment Provision

The Joint Testimony says that the parties have reached agreement (with one qualification by PG&E that we will discuss later) on the general terms of a provision under which the purchasing utility could curtail a QF's output pursuant to one of two options (to be elected by the QF at the time it executes the final Standard Offer 4 contract). Option I allows the utility to curtail for a negative avoided cost or hydro spill condition, without any limits on frequency, duration, or number of curtailments. Option II allows the utility to curtail at its sole discretion for up to 1500 hours annually, during off-peak and super off-peak periods, with a minimum duration of three hours.[28]

The parties request that the Commission approve these curtailment terms and direct the parties to continue workshops to draft the specific language for the curtailment provision. These workshops are needed because agreement in principle was reached too

28 See Appendix A of Exhibit 447 for a detailed summary of the curtailment terms.

late in the negotiations for detailed consideration of wording to fit all aspects of administering the agreed-on terms.

We strongly endorse the concepts of the proposed curtailment provision. It is another step in the integration of QFs in utility system operation. Moreover, it achieves this through use of flexible operating and pricing terms that recognize the diversity of QFs rather than trying to force all QFs into a single rigid mold. We approve the proposed curtailment provision in principle and direct the parties to complete the drafting of the provision in further workshops. We are also considering including such a provision in Standard Offers 1 and 2. Accordingly, we will review as soon as it is available the specific language for the curtailment provision that is developed at the workshops.

F. Provision Disputed by IEP

IEP disagrees with the Joint Testimony's treatment of capacity payments to as-available QFs. Under that treatment, such capacity payments would be limited to a level equivalent to the effective capacity of the QF. IEP would delete this limitation.

As-available QFs are those which cannot or do not wish to commit to provide firm capacity. Often, such QFs use a weather-dependent technology (e.g., wind, hydro). For planning purposes, the purchasing utility converts the nameplate capacity of such QFs to some fraction, designated the "effective" capacity, which is presently derived from aggregate historical performance of QFs using the same technology, and which (together with bid price) is the basis for allocating final Standard Offer 4 contracts to such QFs.

IEP says the limitation systematically underpays as-available QFs. For example, a wind QF with highly reliable equipment will often outperform the average wind QF but will never have that superior performance recognized in its capacity payment.

The justification for the Joint Testimony's treatment (as explained by Edison) is that final Standard Offer 4 prices are predicated on deferral or avoidance of specific resources. The utility can only defer resources equivalent to the long-term effective capacity of as-available QFs signing that offer; the utility cannot defer resources based on temporary levels of capacity produced by as-available QFs that exceed effective capacity. In short, QF capacity is only as valuable as the capacity that the utility can defer as a result of the QF's commitment.

We find that, while there are sound arguments on both sides, Edison's arguments are more persuasive in the context of final Standard Offer 4. We also give some weight to the parties' representation that the Joint Testimony's recommendations must be treated as a balanced whole. Parties to a settlement need room to compromise on issues; no such room exists if the settlement must resolve each issue in exactly the same way as if the issue had been litigated in full. We have concluded that the Joint Testimony's uniform final Standard Offer 4 contract provisions, taken as a whole, are reasonable and in the public interest. That reasonable people might differ on some of the provisions does not negate our conclusion.

G. Provisions Disputed by PG&E

PG&E believes that certain of the agreed-on provisions are unreasonable, at least as applied to its own system. We have allowed some variation between utilities in their respective standard offer provisions (e.g., on QF size for purposes of the telemetry requirements) where a utility-specific need is demonstrated. However, we do not believe that PG&E has made a convincing showing on any of the disputed provisions.

1. Firm Capacity Demonstration Test

The dispute is that PG&E proposes a firm capacity demonstration test that requires the QF to operate at 100% of its firm capacity commitment level for at least 80% of the hours over 30 consecutive days, while the Joint Testimony, in which Edison and

SDG&E concur, has a less stringent test, i.e., operation at 80% or greater capacity level for 30 days.

PG&E fails to show, either that the less stringent test is technically inadequate, or that conditions on the PG&E system require the more stringent test. PG&E simply says the latter test is "not unreasonable." (Concurrent brief, p. 65.) It well may be "not unreasonable" but that does not persuade us to prefer it to a technically adequate test that is acceptable to the other parties. We reject the PG&E proposal.

2. Surplus Sale Option

PG&E would require the final Standard Offer 4 QF either to sell its net output to PG&E or to use some of the generation on-site and sell the surplus to PG&E. Retail sales to end-users would not be permitted.

PG&E concedes that retail sales to certain end-users are permitted when made by QFs operating under other standard offers or nonstandard contracts. Moreover, the Public Utilities Code expressly exempts cogenerators and users of unconventional power sources from public utility status even though they make certain retail sales to a class of end-users specified in the code. PG&E invokes current concerns about system bypass to justify its proposal. However, QFs operating under final Standard Offer 4 seem very unlikely to contribute to uneconomic bypass. This is because final Standard Offer 4 contracts only become available when the utility's resource plan shows a need for baseload or intermediate capacity. PG&E's position is untenable.

3. Emergency Availability

During a system emergency, the utility generally prefers that, so far as possible, generation sources remain connected to the grid and continue energy deliveries. This helps to stabilize the system, while unnecessary separation could exacerbate an abnormal system condition.

The emergency availability provision recommended in the Joint Testimony says that "Seller [i.e., the QF] shall use reasonable efforts to deliver energy during periods of Emergency at an average rate of delivery at least equal to the Effective Capacity. If Seller has previously scheduled an outage which coincides with an Emergency, Seller shall use reasonable efforts to reschedule the outage. If Seller reschedules the outage pursuant to this Section, [utility] shall waive the notice periods for scheduled outages...." (Emphasis in original.)

PG&E's version has an additional requirement, which PG&E inserts between the first and second sentences of the Joint Testimony's provision: "[I]n the event of a PGandE electric system frequency or voltage excursion which exceeds the normal limits of regulation, but does not cause the Protective Apparatus to automatically separate the Generating Facility from the PGandE system, Seller shall not manually separate its Generating Facility from PGandE's system without first notifying and obtaining permission from the PGandE Designated Switching Center. Such permission shall not be unreasonably withheld. Seller shall not alter settings of the Protective Apparatus from the settings established during the pre-parallel inspection." (Emphasis in original.)

The concern that QFs seem to have with PG&E's version is that the version could effectively require the QF to sustain damage to its plant if the relays either do not function or are set at levels sufficient to protect PG&E's equipment but not the QF's equipment. (See cross-examination of PG&E witness Di Pastena by SFG/U/F, Tr. 7971-74.) For example, we think it probable that a utility switching center in an emergency would have higher priorities than to determine whether the relays at a five megawatt QF plant were malfunctioning, even though the consequences to that QF might be serious.

We think that, under a fair reading of the Joint Testimony's emergency availability provision, the QF is already required to continue to deliver energy if it can do so without harm to its equipment. What seems to underlie PG&E's wordsmithing is a concern that some QFs separate from the system even when the frequency or voltage excursion, at least in PG&E's opinion, is not so great as to endanger the QF. However, from the QFs' viewpoint, PG&E is demanding the right to make the final decision on a matter affecting the safety of the QFs' personnel and equipment.

We are satisfied with the approach taken in the Joint Testimony. We also feel strongly that appropriate QF response to emergencies is vital if utilities are to rely on large amounts of QF power. The Joint QF/Utility Consultative Committee that is getting underway offers a suitable forum to discuss technical problems and possible improvements in communication between the utility and QF during emergencies. PG&E should pursue this topic in the committee, particularly since, as PG&E notes, the thousands of QF megawatts already under contract with PG&E are not subject to the type of emergency requirement that PG&E seeks here.

4. Curtailment

As we mentioned in Section IV.E above, PG&E qualifies in one respect its endorsement of the Joint Testimony's curtailment provision. PG&E's support of the 1500 hour curtailment option is conditioned on our determining that the IERs used for PG&E's energy prices should be updated on a quarterly basis. If we do not accept PG&E's update proposal, then PG&E would oppose including in its final Standard Offer 4 an option to limit curtailable hours.

PG&E justifies its position on the basis that, unlike Edison and SDG&E, PG&E's system has a substantial quantity of hydro resources. Unless there is a mechanism for updating IERs frequently, and so capture the impact of various levels of expected hydro generation, PG&E says that the limitations of the 1500 hour curtailment option could result in energy payments above avoided cost.

We think PG&E's linkage of IER updating with curtailment options under the final long-run offer is inappropriate. First, curtailment is a contract drafting issue, while IER updating is not. Neither final Standard Offer 4 nor any other standard offer specifies any particular method for updating IERs. Second, and more fundamental, IER updating affects energy pricing for QFs with variable energy payments (see Section III.A above) but is largely irrelevant to energy pricing for final Standard Offer 4 QFs. For example, the energy payments to such QFs for output corresponding to what would have been delivered by the avoidable resource in Period 2 (the time after the avoidable resource would have come on-line) derive from either (1) an IER fixed when the contract is signed multiplied by the system marginal fuel cost or (2) the avoided plant's heat rate multiplied by the price of fuel that the plant would have consumed. (See D.86-07-004, pp. 79-80a.) The relevant updating for final Standard Offer 4 is the cost of fuel (which we do quarterly), not the IER.

PG&E Exhibit 453 posits, based on ER-6, that large amounts of non-oil/gas-fired generation will appear on the margin for PG&E in wet years by the late 1990s. This should not be a problem because the vast majority of PG&E's QFs, such as those operating under interim Standard Offer 4, have contracts that set no limit on PG&E's ability to invoke hydro spill pricing or negative avoided cost curtailment. The presence in final Standard Offer 4 of an option limiting curtailable hours is logical, considering that the offer is only made available when the utility's resource plan shows a need for baseload or intermediate capacity.

The most surprising part of PG&E's position is that, on the whole, the 1500 hour curtailment option seems preferable from a utility standpoint to the curtailment option limited to negative avoided cost or hydro spill conditions. The incidence of such conditions to date has been extremely low (zero for negative avoided cost), while in contrast the utility can require curtailment under the 1500 hour option whenever the utility finds it economic to do so. We think that the greater flexibility of the 1500 hour option easily outweighs the limit on curtailable hours. Possibly PG&E considers 1500 hours too conservative, given the quantity of hydro on its system; if so, PG&E should have made a utility-specific showing to justify a higher limit, e.g., 2000 hours, such as PG&E has negotiated for some of its existing QF contracts.

We find that Option II (the 1500 hour curtailment option) should be included in PG&E's final Standard Offer 4. We address in D.88-03-026 the question of quarterly versus annual IER updating.

H. <u>Contract Implementation Requirements</u>

The Joint Testimony outlines several steps that need to be taken in conjunction with approval of the final Standard Offer 4 contract form.

1. <u>Allocation of Available Transmission Capacity</u>

We grant the parties' request that each utility be authorized to submit, by advice letter filing, revisions to the respective utility's Tariff Rule 21 (governing QF-utility system interconnections) to provide for the allocation of available transmission capacity on the utility system.

The reason for this request is that final Standard Offer 4 incorporates milestones from the QF Milestone Procedure without providing for the allocation of available transmission capacity. The proposed tariff revisions would say in essence that, for a QF that (1) is not subject to the QF Milestone Procedure, and (2) wins a final Standard Offer 4 contract, entitlement to available capacity on the utility's transmission/distribution system and a priority to such line capacity is established as of the date that the QF's bid is determined to be a winner. The QF thereafter retains its entitlement and priority so long as it does not default in performance of its agreement.

We agree with the parties that the proposed tariff revision is an appropriate means to allocate transmission priority.

2. Other Revisions to Tariff Rule 21 (Edison, PG&E)

Edison and PG&E had included certain provisions in their final Standard Offer 4 compliance filings that the parties agree would more appropriately appear in the operating requirements manual (implementing Tariff Rule 21) of the respective utility. The provisions in question set forth generating facility design and siting requirements.

We authorize Edison to file by advice letter appropriate revisions to its Tariff Rule 21 and, upon our acceptance of such revisions, to delete Sections 6.1(d), 6.1(e), 6.1(f), and 6.3(j) from its final Standard Offer 4 contract form. Of these four sections, only Section 6.3(j) applies to PG&E, and none of these sections applies to SDG&E. We authorize PG&E, as with Edison, to make the appropriate revision and deletion.

3. Utility-Specific Contract Provisions

The Joint Testimony generally sets forth its recommendations by reference to Exhibit 446, which is Edison's proposed final Standard Offer 4 contract form as of June 1987. That form has various provisions and terminology specific to Edison. Appendixes G and H to the Joint Testimony contain a list of utility-specific modifications to Exhibit 446 needed to adapt it for use by PG&E and SDG&E, respectively. The bulk of the modifications serve to correctly identify the purchasing utility and to be consistent with that utility's terminology. (E.g., SDG&E says "semi-peak" rather than "mid-peak.") We agree that PG&E and SDG&E, in conforming their final Standard Offer 4 contract forms, should make these modifications.

V. Response to Comments on ALJ's Proposed Decision

Pursuant to Public Utilities Code § 311 and to our Rules of Practice and Procedure (California Code of Regulations, Title 20, Rules 77 to 77.5), the Proposed Decision of ALJ Kotz was issued before today's decision. Four parties (DRA, PG&E, SDG&E, and Edison) filed timely comments on the proposed decision. Two parties (Cogenerators of Southern California (CSC) and SFG/U/F) submitted late comments, accompanied by motions for leave to file late. We grant their motions.[29] Finally, CSC filed comments replying to part of Edison's comments.

We have made a number of modifications and clarifications in response to these comments. We have also corrected typographical errors and updated several sections where the proposed decision fails to reflect developments in various proceedings that we refer to here. Although many pages have changes, we have made no substantive modifications to the analysis or disposition of issues in the proposed decision.

Findings of Fact

1. An EUE-based ERI method for valuing capacity was adopted in D.86-11-071. The method, as implemented by SDG&E and Edison, (1) produces reasonable results, (2) is reasonably consistent with capacity requirements projected by the CEC in ER-6, and (3) is suitable for use by these utilities in any proceeding before this

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29 ECG requested changes to the proposed decision by letter to ALJ Kotz dated December 17, 1987. ECG's letter did not comply with the rules governing comments, most notably the rule requiring service on all parties (Rule 77.2). On December 22, 1987, ALJ Kotz returned ECG's letter, noting its noncompliance with the comment rules and enclosing a copy of those rules. We are unaware of any action by ECG to cure these defects. Accordingly, we cannot file or consider the comments in ECG's letter.

Commission when projecting capacity need or valuing capacity already on or to be added to their systems.

2. The ERI method, as implemented by PG&E, does not produce reasonable results. A temporary capacity value is needed for use by PG&E for certain QF payments in 1988. A reasonable temporary value would be to continue PG&E's 1987 as-available capacity price ($42 per kilowatt).

3. Further comment is needed on how to make future capacity value adjustments for as-available QFs on PG&E's system. For long-term capacity planning purposes, use by the CPUC of the CEC's target reserve margins for PG&E (as projected in the CEC's most recent Electricity Report) would result in consistent treatment of different types of resource options. Reasonably consistent treatment is one of the chief goals of this proceeding and future resource plan updates.

4. The fact that a given type of generation resource, such as a peaking plant, is nondeferrable under D.86-07-004 does not by itself establish that such a resource can or should be included in a utility's resource plan. The utility must also show that the resource is cost-effective in order to justify such inclusion.

5. Standard Offer 2 and final Standard Offer 4 contain long-term fixed prices and accordingly require long-term forecasts. Such forecasting is done for the PG&E, SDG&E, and Edison systems in the biennial resource plan proceedings, so these proceedings are suitable for setting the fixed payments for these offers.

6. Because of the lack of avoidable megawatts for purposes of final Standard Offer 4 and the continued suspension of Standard Offer 2 for PG&E and Edison, the only long-term fixed prices that need to be established at this time are the capacity price schedules for SDG&E's Standard Offer 2.

7. Variable capacity payments to QFs (chiefly under Standard Offers 1 and 3) depend on short-term forecasts and should be updated annually. ECAC proceedings are well suited for such

updating because they already involve the adoption of assumptions on the utility applicant's loads and resources during the one-year forecast period.

8. Edison's variable capacity payments have been set in its current general rate case (Application 86-12-047), using the ERI method approved in today's decision.

9. SDG&E's variable capacity payments (pending revision in its 1988 ECAC) will equal its annualized fixed costs of a combustion turbine.

10. SDG&E's capacity price table for reinstated Standard Offer 2 needs prices for two blocks of 50 megawatts each (effective capacity). Upon reinstatement, the blocks are to be available until the end of calendar year 1988 or until fully subscribed, whichever occurs first. Prices shown for the second block assume that all QFs from the first block are already on-line. The table is to contain capacity price schedules for each year in which this cohort of Standard Offer 2 QFs is allowed to come on-line (i.e., through 1993), and for all contract lengths to and including 30 years.

11. SDG&E's capacity price calculations for reinstated Standard Offer 2, as described in finding of fact 10, are to assume the refurbishment of Silver Gate but no other additional resources.

12. Reliability models have great and growing importance in CPUC proceedings. The on-going study of computer models pursuant to Assembly Bill 475 (Chapter 1297 of the 1985 Statutes) is the appropriate setting to develop information on the various types of reliability models.

13. "Variable energy payments" are those that are set periodically, based on the current price of the marginal fuel and the current IER for each utility. "Fixed energy payments" are those for which at least the IER is established by contract for some period longer than the update cycle used for recalculating the bases for variable energy payments.

14. "QFs-out" (when used in relation to variable energy payments) represents the computer-modelled dispatch of a utility system with all variably-priced QFs removed. In the same context, "QFs-in" represents system dispatch including all variably-priced QFs anticipated to be on-line during the forecast period. "QFs-in/QFs-out" refers to the average of the IERs calculated by performing both computer runs for a given utility system.

15. Edison's zero-intercept method for calculating the QFs-in IER has the advantage of being relatively insensitive (compared to the instantaneous marginal rate) to minor variations in assumptions.

16. Under certain circumstances, QFs-in/QFs-out does not realistically reflect what a utility would have done to replace short-run QF power. However, these circumstances are likely to exist only when short-run QFs constitute a relatively larger part of a utlity's resource mix than they presently do for PG&E, SDG&E, or Edison. Also, refinements to QFs-in/QFs-out proposed by DRA, SFG/U/F, and IEP could mitigate the problem.

17. QFs-in undervalues short-run QFs so long as the purchasing utility can recover its full cost of replacing QF deliveries, should these fall short of the quantity estimated for purposes of calculating the QFs-in IER. Thus, QFs-in strengthens the utility's market power because only the QFs have to compete at the QFs-in price, while the utility in case of need can dispatch less efficient resources and still recover most of its excess costs through ECAC.

18. QFs-in/QFs-out is the appropriate energy pricing method for final Standard Offer 4 QFs in Period 1, regardless of the pricing method for other QFs receiving variable energy payments.

19. The primary purpose of state and federal policies regarding QF development is to create a pricing structure that captures to the extent possible the efficiency and other benefits of perfect competition in electricity generation. Neither QFs-in

nor QFs-in/QFs-out will fully capture these benefits under existing conditions.

20. A primary function of the standard offers is to reduce the transaction costs of creating power purchase agreements between utilities and QFs.

21. The existence of standard offers also helps in the creation of nonstandard power purchase agreements because the parties to such agreements may be able to use most of the standard provisions and thus to concentrate their efforts on project-specific provisions (e.g., additional performance features) that would benefit both seller and utility.

22. It is appropriate to defer to the biennial update proceeding following ER-7 the contract issue of when and for how long the capacity factor assumed for the avoidable resource should be fixed.

23. The general terms of the curtailment provision proposed in the Joint Testimony are consistent with the Commission's goal of integrating QFs in utility system operation through flexible operating and pricing terms.

24. Under the final Standard Offer 4 methodology, the value of a QF's capacity is measured in terms of the capacity that the utility defers or avoids as a result of the QF's commitment.

25. PG&E has not shown, either that the firm capacity demonstration test proposed in the Joint Testimony is technically inadequate, or that conditions on the PG&E system require a more stringent test.

26. Sales of electricity by final Standard Offer 4 QFs to certain end-users are very unlikely to contribute to uneconomic bypass.

27. The relevant provision in the Joint Testimony reasonably specifies the QF's duties in a system emergency.

28. The relatively high dependence of PG&E's system on hydro resources has an impact on the desirable frequency of IER updating;

however, such updating has only a small effect on energy pricing for final Standard Offer 4 QFs.

29. It is reasonable to establish a mechanism in the respective utilities' tariff rules for allocating available transmission capacity to final Standard Offer 4 QFs. These tariff rules could also appropriately include the respective utilities' technical specifications for QF-utility system interconnections.

30. The implementation of ramped payment streams as proposed in the utilities' compliance filings is consistent with the derivation of the utilities' own revenue requirements and thus preserves ratepayer indifference as between QFs deferring a given resource and the utility acquiring it.

Conclusions of Law

1. The EUE-based ERI method, as implemented by Edison and SDG&E, should be used by these utilities in any proceeding before this Commission when projecting capacity need or valuing capacity already on or to be added to their systems.

2. PG&E's 1987 as-available capacity price ($42 per kilowatt) should be continued until adoption of an appropriate method for adjusting variable capacity payments to QFs on PG&E's system.

3. For long-term capacity planning purposes, the CEC's target reserve margins for PG&E (as projected in the CEC's then-current Electricity Report) should be used.

4. SDG&E should be directed to file a revised capacity price table for reinstated Standard Offer 2 consistent with findings of fact 10 and 11.

5. A utility should show that any given resource proposed for future development in its resource plan is cost-effective, regardless of whether the resource would be deferrable by QFs.

6. The long-term forecasting needed for Standard Offer 2 and final Standard Offer 4 should be done biennially, and these offers

should be updated in coordination with the CEC's Electricity Report process.

7. Variable capacity payments to QFs should be updated annually in ECAC proceedings.

8. The QFs-in/QFs-out method for calculating short-run energy prices is consistent with the PURPA avoided costs standard.

9. To the extent that changes in ECAC and possibly other developments create a more competitive environment and move the electric industry closer to a true spot market, it is consistent with PURPA to reconsider marginal energy cost pricing for short-run QFs.

10. The final Standard Offer 4 contract provisions set forth in Exhibit 446, as supplemented by the agreements set forth in Exhibit 447, should be approved in their entirety. Proposals by IEP and PG&E to modify those provisions should be rejected.

11. The curtailment terms set forth in Appendix A of Exhibit 447 should be approved and the parties should be directed to continue workshops to draft conforming contract language.

12. PG&E and Edison should be authorized to file advice letter revisions to their respective tariff rules regarding technical specifications for QF-utility interconnections, as described in Section IV.H.2 of this decision. PG&E, SDG&E, and Edison should also file advice letter revisions to include in Tariff Rule 21 of each utility a mechanism for allocating available transmission capacity to final Standard Offer 4 QFs.

13. The capacity factor updating issue should be deferred to the biennial resource plan update proceeding following ER-7. Save for this issue, PG&E, SDG&E, and Edison should file a complete final Standard Offer 4 in compliance with this decision, such filing to be due no later than 90 days after today.

14. This opinion and order should be made effective today in order to expedite completion of the work in implementing final Standard Offer 4 and reinstating Standard Offer 2.

15. PG&E's petition for modification of D.86-07-004 should be granted with respect to the proposed treatment of improvements to hydroelectric projects in the context of relicensing proceedings.

FOURTH INTERIM ORDER - COMPLIANCE PHASE

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (Edison) shall use the capacity valuation method described in finding of fact 1 and conclusion of law 1 for purposes of the biennial resource plan update proceeding and in any other proceeding before this Commission when projecting capacity need or valuing capacity already on or to be added to their systems.

2. The capacity price for as-available Qualifying Facilities (QFs) on the system of Pacific Gas and Electric Company (PG&E) shall continue to be $42 per kilowatt. A schedule for comment on the method for future adjustments to PG&E's variable capacity payments, including the proposal described in Section II.E of today's decision, shall be set by ruling of the assigned Commissioner or Administrative Law Judge.

3. For long-term capacity planning purposes in proceedings before this Commission, the target reserve margins for PG&E as shown in the then-current Electricity Report of the California Energy Commission (CEC) shall be used.

4. SDG&E shall file within 30 days of the date of issuance of this decision a revised capacity price table for reinstated Standard Offer 2 consistent with findings of fact 10 and 11. With the limitations stated in those findings, Standard Offer 2 is reinstated for SDG&E, effective 30 days after the filing of the revised capacity price table and of the amendments to Application 82-03-78 previously ordered in Decision 87-12-056. SDG&E shall serve these filings on all parties to Application 82-04-44 et al.

5. Division of Ratepayer Advocates shall study the reliability models used by the parties in this proceeding and shall include its observations in future reports prepared pursuant to Public Utilities Code Sections 1821-1824. This study shall include a description and comparison of the various models and how they are calibrated, and shall recommend any appropriate modeling conventions to be used in future proceedings before this Commission.

6. Division of Ratepayer Advocates, in coordination with CEC Staff, shall hold a public workshop to discuss potential improvements in analyzing electric system reliability and capacity valuation, including the value-of-service approach.

7. Variable capacity payments to QFs shall be updated annually in Energy Cost Adjustment Clause (ECAC) proceedings.

8. The final Standard Offer 4 contract provisions set forth in Exhibit 446, as supplemented by the agreements set forth in Exhibit 447, are approved in their entirety.

9. The curtailment terms set forth in Appendix A of Exhibit 447 are approved in principle. The parties shall file their recommendations on final Standard Offer 4 contract language conforming to these terms within 90 days of the date of issuance of this decision. The parties are strongly encouraged to develop a joint recommendation for the Commission's consideration.

10. PG&E and Edison shall file advice letter revisions to their respective tariff rules regarding technical specifications for QF-utility interconnections (Tariff Rule 21) in order to incorporate certain material, as described in Section IV.H.2 of this decision. PG&E, SDG&E, and Edison shall also file advice letter revisions to the same rule to include a mechanism for allocating available transmission capacity to final Standard Offer 4 QFs. These advice letter revisions shall be filed within 90 days of the date of issuance of this decision.

11. The capacity factor updating issue shall be deferred to the biennial resource plan update proceeding following the CEC's Seventh Electricity Report.

12. PG&E, SDG&E, and Edison shall file a complete final Standard Offer 4 in compliance with this decision within 90 days of the date of issuance of this decision.

13. Unlike other generation resources, improvements to hydroelectric projects proposed in the context of relicensing proceedings at the Federal Energy Regulatory Commission shall be treated as generically unavoidable by QFs. In a biennial resource plan update proceeding, the resource plan of a utility applicant shall reflect such anticipated improvements by identifying the projected capacity, output, and operational date of each such improvement, but need not otherwise describe the improvement or justify its cost-effectiveness.

14. Except to the extent granted in Ordering Paragraph 13, PG&E's petition for modification of Decision 86-07-004 is denied.

This order is effective today.

Dated MAR 23 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

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

Victor Weisser, Executive Director

APPENDIX A
Page 1

Table of Acronyms and Abbreviations

This table contains an expansion of each acronym and abbreviation used in today's decision. Following the expansion is a reference to the section in the body of the decision where the acronym or abbreviation first appears.

ALJ	Administrative Law Judge (II.E)
BTU	British thermal unit (III.A)
CEC	California Energy Commission (II)
CFR	Code of Federal Regulations (III.E.4)
CPUC or Commission	California Public Utilities Commission (II.A)
CSC	Cogenerators of Southern California (V)
D.	Decision (I)
DRA	Division of Ratepayer Advocates of CPUC (formerly Public Staff Division) (I)
ECAC	Energy Cost Adjustment Clause (I)
ECG	Energy Consulting Group (II.G)
Edison	Southern California Edison Company (I)
ER-6	The CEC's Sixth Electricity Report (II)
ERI	Energy Reliability Index (I)
EUE	Expected Unserved Energy (I)
FERC	Federal Energy Regulatory Commission (II.A)
IEP	Independent Energy Producers Association (I)
IER	Incremental Energy Rate (III)
LOLE	Loss of Load Expectation (II)

APPENDIX A
Page 2

LOLP	Loss of Load Probability (II.E)
MAREL	Multi-Area Generation System Reliability Model (II.F)
PG&E	Pacific Gas and Electric Company (I)
PURPA	Public Utility Regulatory Policies Act of 1978, as amended (III.E.3)
QF	Qualifying Facility (I)
R.	Order Instituting Rulemaking (III.E.4)
SDG&E	San Diego Gas & Electric Company (I)
SFG/U/F	Santa Fe Geothermal, Inc., Union Oil Company of California, and Freeport-McMoRan Resource Partners (II.D)
Tr.	Reporter's Transcript (IV.G.3)

ALJ/SK/tcg

Decision ____________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982 July 19, 1982, July 11, 1983, August 2, 1983, and August 21, 1986)
	Application 82-04-46
	Application 82-04-47
	Application 82-03-26
And Related Matters.	Application 82-03-37
	Application 82-03-62
	Application 82-03-67
	Application 82-03-78
	Application 82-04-21

THIRD INTERIM OPINION, COMPLIANCE PHASE:
CAPACITY VALUATION; VARIABLE ENERGY PRICING;
STANDARD OFFER 4 MILESTONE, CONTRACT DRAFTING ISSUES

INDEX

INDEX

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Decision ___________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983, August 2, 1983, and August 21, 1986)
And Related Matters.	Application 82-04-46 Application 82-04-47 Application 82-03-26 Application 82-03-37 Application 82-03-62 Application 82-03-67 Application 82-03-78 Application 82-04-21

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INDEX

INDEX

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I. Introduction

In Decision (D.)87-05-060, our first interim compliance phase opinion, we dealt with certain non-resource planning issues in the implementation of final Standard Offer 4. We have since held further hearings in this proceeding in June and July. These hearings concerned resource planning and uniform contract provisions for final Standard Offer 4, and possible reinstatement of Standard Offer 2. In our second interim compliance phase opinion, we found that (1) there are presently no avoidable resources for purposes of final Standard Offer 4, and (2) that Standard Offer 2 should be reinstated for San Diego Gas & Electric Company (SDG&E).

Today's decision, our third interim opinion, deals with the two remaining pricing methodology issues for all standard offers and the development of a final Standard Offer 4 contract form with (so far as possible) uniform provisions and terminology for all utilities.

We find that the utilities have generally complied with our direction in D.86-11-071 regarding creation of a reliability target and capacity value adjustment based on Expected Unserved Energy (EUE). We find the resulting Energy Reliability Index (ERI) method should be used by SDG&E and by Southern California Edison Company (Edison) for valuing capacity from any source, including both Qualifying Facility (QF) and non-QF sellers and the utility's own plants and projects. We find the ERI does not yield reasonable results for Pacific Gas and Electric Company (PG&E), and we adopt a temporary capacity value for use by PG&E in 1988.

For QFs receiving variable energy payments, we confirm our conclusion in D.85-07-022 that final Standard Offer 4 QFs

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For QFs receiving variable energy payments, we confirm our conclusion in D.85-07-022 that final Standard Offer 4 QFs on-line in Period 1 of their contracts should have such payments calculated according the "QFs-in/QFs-out" method. All other QFs receiving variable energy payments should also have such payments calculated according to this method for the time being. However, for the latter QFs, we may shift later to marginal cost pricing (i.e., QFs-in), contingent on appropriate changes being made to utilities' cost recovery through the Energy Cost Adjustment Clause (ECAC) procedure, so that the benefits of marginal cost pricing flow through to ratepayers.

We approve the uniform final Standard Offer 4 contract provisions jointly sponsored by QF and utility representatives and by Public Staff (renamed the Division of Ratepayer Advocates (DRA) after the close of these hearings). We reject certain alternate provisions proposed by Independent Energy Producers Association (IEP) and by PG&E.

II. Capacity Valuation

We use capacity valuation in many ways, but in this proceeding the chief functions are determining capacity payments to QFs and testing the cost effectiveness of proposed resource additions. All parties agree with the goal that the same capacity valuation method be used for both functions. All parties also agree that the capacity valuation method must be able (1) to measure the utility's relative need for capacity over a given time frame (based on an appropriate reliability target), and (2) to make corresponding adjustments to the utility's capacity payments.

The ERI method that we adopted in D.86-11-071 was intended to satisfy these goals. These goals are compromised somewhat in that the California Energy Commission (CEC) has its own target reserve margins for each utility, using the CEC's reliability model and a target based on a one-day-in-10-years Loss of Load Expectation (LOLE). (The ERI method has a reliability target expressed as EUE and derived by analysis of the utility system in one historical reference year.) Thus, there was confusion in the resource plan hearings on whose target reserve margin was to be used by the utility for purposes of its CEC-based scenario.

Fortunately, the methodological difference does not significantly affect our conclusions at this time on either avoidable resources or capacity payments. As we discuss shortly, the ERI as implemented by SDG&E and Edison yields target reserve margins almost identical to those specified for the respective utilities by the CEC in its current Electricity Report (ER-6). This is not the case for PG&E; however, there do not appear to be any avoidable resources for PG&E even using the EUE target, which PG&E finds to be relatively more stringent than LOLE. Thus, we arrive, via a different path, at results that are in fact consistent with ER-6.

There is general agreement that the utilities have complied with the ERI method specified in D.86-11-071. The remaining ERI issues concern input assumptions and updating. The ERI is a way to calculate short-term and long-term capacity values, given the utility's anticipated loads and resources for the forecast period. Long-term capacity values are needed for the standard offers with fixed capacity prices (Standard Offers 2 and 4). Short-term capacity values are needed for the standard offers with variable capacity prices (primarily Standard Offers 1 and 3, plus a few QFs under interim Standard Offer 4). Therefore, input assumptions will affect prices under all the standard offers. Many parties dispute the utilities' assumptions on loads and resources from which ERIs (and ultimately capacity values) are calculated.

A. Nondeferrability and Cost Effectiveness

We will analyze planning assumptions in detail in the final decision for the compliance phase. However, one oft-repeated criticism leveled at the resource plan filings deserves immediate comment. The criticism is that Edison and PG&E show many new utility resources coming on-line during the next eight years, despite alleged capacity surpluses, and without a showing of cost effectiveness. (An example is Edison's Big Creek Expansion Project.) Edison responds that the additions are mostly peaking resources, thus nondeferrable by QFs and, in Edison's view, not subject to screening for cost effectiveness.

Edison misreads D.86-07-004.[1] Nondeferrable generation resources don't belong in a resource plan unless they are shown to be cost-effective.[2] To include such resources unfairly reduces capacity payments to QFs and violates least-cost planning principles. Reliance on such a resource plan would limit QF

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1 We have a four-part standard for a showing of nondeferrability on a project-specific basis. The showing must: "(1) establish the project's cost-effectiveness, (2) set forth the aspects of the project claimed to justify a finding of nondeferrability, (3) quantify the economic and operational benefits of such aspects, and (4) describe the impact of attempted deferral through the use of 'adders' and standard offer contracts." (D.86-07-004, mimeo., pp. 83-84.) The same decision says that peakers are nondeferrable; however, that generic statement can only be held to cover part (2) of the required showing. There is such a thing as a capital-intensive peaking facility--pumped storage projects such as Edison's Big Creek and PG&E's Helms are examples. These projects may have unique system benefits, but that doesn't excuse the utility from showing that the benefits are worth the costs.

2 Ideally, this statement would also apply to conservation and load-management programs. We are currently undertaking with the CEC and interested parties the modifications to the joint CEC/CPUC Standard Practice Manual needed to ensure that strategies for increasing electrical supply and managing or reducing electrical demand are compared on "a level playing field." See Section I.B.4.a of our Second Interim Opinion - Compliance Phase.

opportunities at ratepayer expense. That is obviously unacceptable.

There is an exception to the above generalization on nondeferrability and cost-effectiveness. The exception relates to hydro relicensing. In a petition for modification of D.86-07-004, PG&E has asked that "improvements to hydroelectric projects proposed in the context of relicensing proceedings" at the Federal Energy Regulatory Commission (FERC) be treated as generically nondeferrable. According to PG&E, "[i]f the relicensing improvements are 'avoided' by [a Standard Offer 4] contract, PG&E may be precluded from complying with the Federal Power Act's mandate to develop the resource" and thus "be unable to propose plans giving its customers the best chance to retain these valuable resources."

No party has opposed PG&E's request, and we have decided to grant it. Relicensing improvements are a unique case, in that the failure to pursue the improvement could cause the loss (through denial of relicensing) of an existing resource. Furthermore, the FERC reviews the cost-effectiveness of the proposed improvement. Thus, it is appropriate to treat relicensing improvements as generically unavoidable by QFs. The resource plan of a utility applicant should reflect such anticipated improvements by identifying the projected capacity, output, and operational date of each such improvement, but need not otherwise describe the improvement or justify its cost- effectiveness.

B. <u>ERI Updates</u>

Our final compliance phase decision will have a complete picture of the periodic updating process for the standard offers. We discuss ERI updates now in order to clarify why we are setting some QF capacity payments here and why some will be set in other proceedings.

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B. <u>ERI Updates</u>

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We do such forecasts in our biennial resource plan proceedings, of which this is the first. Thus, the fixed payments in these offers will be set in the resource plan proceeding.

We have previously determined that none of the utilities now has avoidable megawatts for purposes of final Standard Offer 4, and we have also continued the suspension of Standard Offer 2 for PG&E and Edison. Thus, the only long-term fixed prices to be set in today's decision are the capacity price schedules for SDG&E's Standard Offer 2.

Variable capacity payments (for the most part, contracts under Standard Offers 1 or 3) depend on short-term forecasts and should be updated annually. Such payments should not be set in this proceeding, which is biennial and which is largely insensitive to things such as business cycles that may have significant impact for the short term. Our annual ECAC proceedings are ideally suited for such updating because they already require us to adopt assumptions on the utility's loads and resources during the one-year forecast period. ECAC proceedings establish the utility's marginal costs for several purposes; this feature should limit the "gaming" that we fear would occur in a proceeding held only to set short-run QF prices.

Thus, we will update variable capacity payments each year. In the future, this annual update will normally be done in the ECAC proceeding for each utility.[3] Capacity values for SDG&E and Edison will be computed using the ERI method specified in

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3 Since this is the first year of the annual update cycle, we must deviate somewhat from our intended reliance on the ECAC proceeding to update variable capacity payments. See the utility-by-utility discussion that follows.

D.86-11-071; for PG&E, we are using a temporary capacity value adjustment, described in Section II.E below.[4]

C. Edison

We first reviewed Edison's proposed EUE target in D.86-11-071 and there expressed concerns over its derivation. Edison provided an elaboration in its compliance phase testimony, and we are now satisfied that the proposal, which couples the EUE

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4 Our final decision in this proceeding will deal with updating generally. However, so that everyone understands that we are not burdening the ECAC proceeding with additional litigation, we briefly summarize now what is involved in the updating of variable capacity payments. The ECAC proceeding already develops a sales forecast and supply assumptions; ERI updating applies a formula (described below) to the adopted ECAC assumptions to come up with the capacity price.

First, an annualized cost of a combustion turbine for the particular utility is needed. This cost was formerly set in the utility's general rate case; in the future, it will be updated in the biennial resource plan update proceeding, still using the costing methodology established in D.82-12-120. Second, the utility's latest established combustion turbine cost will be escalated using the previous year's recorded GNP deflator. (See D.87-05-060, mimeo., p. 29.) Third, the ERI is calculated using (1) the load and resource assumptions developed during the ECAC proceeding, and (2) the ERI formula described in D.86-11-071 and applied to the block of QFs receiving variable capacity payments. Fourth and finally, the annualized combustion turbine costs are multiplied by the calculated ERI.

This approach to ERI updating eliminates an issue from our general rate case proceedings and ensures consistency with the results of our ECAC proceedings without adding issues to the latter.

target with a target reserve margin, is reasonable and should be approved.[5]

Edison's target reserve margin seems consistent with CEC planning criteria. Table 2-13 of ER-6 ("Reserve Margin Assumptions for Key Years") sets the reserve requirement for the Edison planning area at 19.30% in 1990, declining to 17.50% in 1997 and therafter. Edison's target reserve margin is 18 ± 2%. Thus, the CEC's reserve requirement throughout the ER-6 forecast period falls within the narrow band of the target reserve margin that we approve for Edison for use in conjunction with the standard offers.

Under the former capacity price updating procedure, this issue was included in each utility's general rate case. Thus, although the methodological questions for capacity valuation have been in this proceeding, the parties to Edison's current general rate case (Application 86-12-047) have litigated the question of what resources are likely to be available in 1988 for purposes of adjusting Edison's variable capacity payments to QFs. We will therefore set these payments in a decision in the general rate case, using the ERI method approved by today's decision. Future updates to Edison's variable capacity payments will be done annually in an Edison ECAC proceeding.

D. SDG&E

D.86-11-071 reviewed SDG&E's initial EUE proposal and requested certain clarifications and additional conservatism in the choice of a reliability target. SDG&E responded to both requests

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5 EUE is a probabilistic concept, while the target reserve margin is deterministic but far easier to calculate. Essentially, under D.86-11-071, the utility would always plan to meet its target reserve margin (within a stated tolerance) but would base its capacity payments to QFs on EUE whenever such analysis indicates that higher-than-targeted reserves are needed in order to maintain system reliability at the level derived from the historical reference year.

in its compliance phase testimony. Also, at the request of Santa Fe Geothermal, Inc., Union Oil Company of California, and Freeport-McMoRan Resource Partners (SFG/U/F), SDG&E provided a sensitivity analysis showing the reaction of its ERI to changes in input data. We are satisfied that the proposal (which, like Edison's, couples the EUE target with a target reserve margin) provides a reasonable method for valuing capacity on the SDG&E system.

There is little divergence between CEC planning criteria and SDG&E's target reserve margin. In ER-6, the CEC assumes a capacity reserve requirement for SDG&E of 18.14% in 1990. This declines rapidly to 15.30% in 1992, then declines slowly to 14.23% in 1997, and remains at that level thereafter. SDG&E's target reserve margin is 15 ± 1%. Thus, except for the earliest years, SDG&E and the CEC are very close in their projected reserve requirements for the ER-6 forecast period.

In SDG&E's most recent general rate case (Application 84-12-015), we deferred to this proceeding the issue of capacity values for purposes of all the standard offers. (See D.85-12-108, mimeo., p. 88.) We therefore deal with SDG&E's variable capacity payments in today's decision. Consistent with the discussion in Section II.B above, future updates to SDG&E's variable capacity payments will be done annually in an SDG&E ECAC proceeding.

SDG&E's variable capacity payments are based at this time on the full annualized fixed costs of a combustion turbine. In 1988, such payments should be based on the annualized fixed costs multiplied by SDG&E's ERI for that year. SDG&E must supplement its testimony in one respect in order to perform this calculation: SDG&E's cost for a combustion turbine, shown as $597 per kilowatt (Exhibit 437), needs to be annualized, using the cost of capital assumptions specified in D.86-07-004.

We have decided, based on SDG&E's near-term need for capacity, to set SDG&E's ERI for 1988 at 1.0. This is a qualitative judgment, but such a judgment is necessary because the record in this proceeding lacks an appropriate short-range forecast (such as we would have in an ECAC proceeding) with which to perform the quantitative analysis specified in D.86-11-071.

We have four problems with SDG&E's proposed capacity price tables for reinstated Standard Offer 2. First, pursuant to our second interim opinion, there should be two 50 megawatt blocks, instead of two 100 megawatt blocks as shown in Exhibit 430.[6] Second, the tables need to be completed with capacity price schedules for each year in which the Standard Offer 2 QF is allowed to come on-line, and for all contract lengths to and including 30 years.[7] (The schedules for the second block should assume for each year that all QFs from the first block are on-line.) Third, we are puzzled by the column in Tables 7B and 7C (Exhibit 430) with the heading "30 YEAR LEVELIZED PAYMENT 15 YEAR DEFERRAL." Standard Offer 2 QFs do not defer or avoid power plants; the capacity payment to be levelized is the fixed cost of a combustion turbine (possibly adjusted in the early years of the contract if the ERI is less than 1.0) for the entire period of the contract, i.e., as much as 30 years. SDG&E will need to explain and correct this column, as appropriate.

Our fourth problem concerns the additional resources assumed by SDG&E when calculating Standard Offer 2 capacity prices.

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6 SDG&E endorses this change in its concurrent brief.

7 It appears at present that all of the hurdles to reinstating Standard Offer 2 for SDG&E will be cleared by the end of 1987. These blocks of Standard Offer 2 megawatts should only be available until the end of calendar year 1988 or until fully subscribed, whichever occurs first. Since the Standard Offer 2 QF has five years after contract signing within which to come on-line, SDG&E must produce capacity price schedules for each year through 1993. In the biennial resource plan proceeding to follow ER-7, we will consider authorizing additional blocks under updated capacity price schedules.

We agree with IEP that the only resource that SDG&E should add to its resource plan before computing Standard Offer 2 capacity prices is the Silver Gate refurbishment. Had we found avoidable megawatts for purposes of Standard Offer 4, those would have been added to the resource plan and Standard Offer 2 capacity prices computed under the assumption that Standard Offer 4 would be fully subscribed.[8] We did not accept SDG&E's recommendation on avoidable megawatts, however, and consequently there are no Standard Offer 4 resources to augment SDG&E's supply. The refurbishment of Silver Gate, though not avoidable under Standard Offer 4, is cost effective in all of the SDG&E planning scenarios, at estimated fixed costs much less than a combustion turbine. It seems reasonable for a utility needing capacity but not energy (which is SDG&E's situation in at least the early years in the deferral window) to choose the lowest capital cost resource addition (here, Silver Gate) and to add it ahead of more expensive alternatives, including Standard Offer 2 QFs.

Thus, we direct SDG&E to make the above adjustments to its Standard Offer 2 capacity price tables. Also, pursuant to our second interim opinion, we are reviewing comments on queue management and on certain SDG&E proposals for incorporating milestone and curtailment features of final Standard Offer 4 in reinstated Standard Offer 2. We are scheduling the filing of these adjustments and our consideration of the comments so that Standard Offer 2 can in fact be reinstated in our final compliance phase decision, to be issued shortly.

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8 As stated in D.86-07-004, "[S]hortage costs for short-run QFs should be computed to assume full subscription of final Standard Offer 4." (Id., p. 71, n. 42.)

E. PG&E

PG&E was the first of the utilities to have a Commission-approved capacity value adjustment.[9] In approving that adjustment, we noted several deficiencies in PG&E's approach. We urged then, and have continued since to urge, that PG&E develop a reliability target based on EUE. PG&E has explored several approaches in the interim, and has also developed an EUE-based ERI that follows our directive in D.86-11-071. We are at long last persuaded that the EUE-based ERI in this form, however suitable it may be for Edison and SDG&E, is not a reasonable way to adjust capacity value on PG&E's system.

The chief reason for our conclusion is that EUE (and apparently other probabilistic measures of reliability) varies exponentially in relation to changes in loads or resources, and that degree of sensitivity seems to us inappropriate for a utility system, such as PG&E's, that is highly dependent on as-available resources such as hydro.

Exhibit 454 illustrates this sensitivity. At the request of the assigned ALJ, PG&E calculated ERIs for 1988 using its existing capacity value adjustment method, which has a target based on Loss of Load Probability (LOLP). Pursuant to that request, PG&E combined assumptions from its current ECAC proceeding with dry and average hydro year data. The results show that under average hydro conditions, PG&E's LOLP-based ERI would be 0.22--in other words, the system would have capacity much in excess of the reliability target. Under dry conditions, the LOLP-based ERI would be 1.11,

9 This first ERI was adopted in PG&E's test year 1984 general rate case, D.83-12-068 in Application 82-12-48. For the subsequent consideration in the present proceeding of that ERI and other approaches to capacity value adjustment, see D.86-07-004, pp. 27-30, 81, and D.86-11-071, pp. 1-17.

which says that the system would not meet its reliability target--in other words, it would be capacity-short. An EUE-based ERI would similarly show extreme sensitivity to hydro availability.

The EUE-based ERI developed by PG&E also seems excessively conservative. In D.83-12-068, where we first urged PG&E to develop an EUE target, there is certainly no indication that we intended a more stringent reliability criterion than the one-day-in-10-years LOLP used for the earlier ERI. However, PG&E's implementation of the EUE target described in D.86-11-071 seems to have had that result. According to PG&E (see Exhibit 416), its tables showing annual reserve margins and ERIs with the EUE target imply reserve requirements (to reach an ERI of 1.0) that exceed 30%. In contrast, the reserve requirements implied by PG&E's value-of-service approach are around 20%, and the reserve requirements implied by the former LOLP target (which PG&E feels is itself too stringent) tend to be less than 25%. (Id., pp. B III-11, -12.) We also note that the capacity reserve requirements shown in ER-6 for PG&E appear much lower than those resulting from PG&E's EUE target.[10]

PG&E has many other criticisms of the EUE approach described in D.86-11-071. Some of these criticisms are generic to the approach, while others are specific to PG&E's circumstances. We agree with PG&E that there is a degree of arbitrariness and subjectivity in the approach's reliance on one historical reference year; however, some subjectivity inheres in any reliability target that we know of. For example, as PG&E witness Poland candidly acknowledges, PG&E's value-of-service approach (compared to EUE, LOLP, et al.) makes some kinds of subjective judgments unnecessary

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10 For the Northern California supply planning area, which includes PG&E and the Sacramento Municipal Utility District, ER-6 shows a reserve requirement of 22.60% in 1990, declining to 20.04% in 1997 and thereafter.

but requires other kinds of subjective judgments. This record doesn't enable us to determine that one approach is more subjective than another, or that the more subjective approach thereby has less validity.

On the other hand, we agree with PG&E that the interaction of various conservatisms in our EUE approach seems to produce unreasonable results in this case. We would expect that PG&E, because of its size and the importance of weather-dependent resources to its system, would have relatively higher reserve requirements than SDG&E or even Edison. This expectation is consistent with the CEC's projected capacity requirements for the respective systems in ER-6. Nevertheless, the EUE approach implies very much higher reserve margins for PG&E than what we have previously found prudent or necessary. We will not adopt such higher reserve margins without thinking through their implications for system bypass and the ultimate question of how much reliability are PG&E's customers willing to pay for.[11]

Since we do not reinstate Standard Offer 2 for PG&E at this time, we need not adopt a long-term capacity price table for PG&E in today's decision. However, we must address as-available capacity prices for 1988. We think the most supportable action on this record is to continue in effect the 1987 price ($42 per kilowatt) which already reflects a substantial discount (based on

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11 PG&E has obviously made a good-faith effort to comply with our direction in D.86-11-071 to develop this EUE approach. The fact that PG&E made such an effort, and that PG&E has provided a scholarly and dispassionate critique of the approach, also incline us to give weight to PG&E's objections.

last year's ERI of 0.62) from the full annualized fixed costs of a combustion turbine.[12]

For future adjustments to PG&E's variable capacity payments, we invite comment on the following proposal. We would make such adjustments based on DRA's target reserve margin proposal from Phase II of this proceeding, with slight modifications. The target reserve margin would be taken from the CEC's most recent ER. The ERI would have a ceiling of 1.0 and a floor of 0.4. The ceiling price would be paid whenever the projected reserve margin for the forecast year (as determined in a PG&E ECAC proceeding) would be equal to or less than the target. The ERI would decline linearly until the projected reserve margin is six percentage points over the target; at or beyond that point, PG&E would pay the floor price for as-available capacity.[13]

We recognize that in a wet year, and in many average years, the floor price will result in modest capacity overpayments to as-available QFs; however, as Exhibit 454 shows, the ceiling price will result in capacity underpayments in virtually any dry

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12 Since we are continuing the 1987 capacity payment without inflation adjustment, the implicit ERI is slightly lower than that in effect for 1987. The result seems at least qualitatively consistent with PG&E's current circumstances. The 1987 ERI derives from PG&E's LOLP-based capacity value adjustment that we approved in D.83-12-068. We know that that ERI was predicated on a very low projection of QFs coming on-line. On the other hand, both D.83-12-068 and Exhibit 454 in the present proceeding suggest that PG&E's 1988 ERI might be higher than in 1987 rather than lower. The dim prospects for return to service of Rancho Seco also suggest that any marked decline in PG&E's ERI for next year is unwarranted.

13 This formula would also apply to those few interim Standard Offer 4 QFs that receive variable capacity payments.

The suggested floor price derives from the cost of refurbishing a combustion turbine (as indicated by SDG&E's data for Silver Gate) compared to the cost of constructing a new one.

year, no matter how large the apparent capacity surplus on PG&E's system. This seems to be a reasonably balanced approach to adjusting variable capacity payments on a utility system where hydro plays such an important part.

The above proposal is not intended for long-term planning purposes. However, as PG&E has noted, PG&E's own thermal power plant projects receive certification from the CEC based on conformity with the CEC's projected capacity requirements from the most recent ER. We think that the resource planning criteria applied by the various regulatory agencies should be reasonably consistent, and since we have rejected the EUE-based ERI for PG&E, it seems logical that we use the current CEC criteria in our own proceedings whenever capacity planning on PG&E's system is at issue.

To summarize, we will use EUE-based ERIs for SDG&E and Edison, and CEC-based target reserve margins for PG&E, in our capacity planning approach for the respective utilities. The only issue that remains open is the short-term capacity value adjustment for PG&E. After taking comments on our floor/ceiling proposal, we hope to adopt an adjustment method in the final decision of this compliance phase.

F. Reliability Models and Value-of-Service

The record of the resource plan hearings shows the growing importance of reliability models in CPUC proceedings. The number of such models, and the CEC's reliance on MAREL, makes it desirable for us to increase our understanding of them. We should know how such models are calibrated and how they differ from (or are similar to) the production cost models with which we are more familiar.

Also, the EUEs calculated by the utilities seem anomalous when compared with each other. Specifically, PG&E's and SDG&E's EUEs bear roughly the same proportion as their respective peak demands. This seems logical. Edison's EUE calculations, on the other hand, are proportionally much lower than PG&E's or SDG&E's. This does not affect the validity of the reliability targets or the ERI. As SDG&E points out, there are many reliability models, using different methods to calculate EUE; what matters is (1) the internal consistency of a given model, and (2) the consistent use of a single reliability model by each utility. Still, it is puzzling that the absolute value of the EUEs calculated by different models seems to vary by an order of magnitude.

Pursuant to Assembly Bill 475 (Moore, Chapter 1297 of the 1985 Statutes), we investigated and have prepared a report to the California Legislature on computer models used in our proceedings. We are also developing rules for public access to such models under that law. Our ongoing study of computer models is the appropriate setting to develop information on reliability models. DRA should evaluate the reliability models used by the parties in this proceeding and include its findings in future reports prepared pursuant to Assembly Bill 475. This evaluation should include a description and comparison of the various models and how they are calibrated, and should recommend any appropriate modeling conventions to be used in future proceedings.

Finally, both the CPUC and the CEC are committed to improving our analyses of reliability and capacity valuation. For example, the CEC is investigating potential refinements to MAREL, and both commissions have noted with interest PG&E's ground-breaking analysis of the value-of-service approach to capacity valuation. We believe that approach has potential advantages over traditional measures. Whether (and when) that approach can be substituted for traditional measures is another question. DRA, in coordination with CEC staff, should hold a workshop, probably after our final compliance phase decision, to determine what are the utility plans in this area, and to develop a consensus on goals and priorities.

G. Ramped Payment Stream

The Energy Consulting Group (ECG) raises a final Standard Offer 4 implementation issue that implicates capacity valuation, cost-effectiveness analysis, and calculation of the fixed (or capital) costs of the deferred resource.

One part of the payments that the final Standard Offer 4 QF receives is based on the fixed costs of the deferred resource on an annualized basis. This part is established in "real" terms (discounted by the result of the second price auction if the offer is oversubscribed) at the time the QF enters into its contract. This part is also adjusted ("ramped") according to actual inflation during the contract. The ramped payment stream provides substantial price certainty to QFs but avoids the risks of front-loaded payments and keeps all parties indifferent as to the impact of inflation. We derive the ramped payment stream using the so-called "deferral method" (see D.87-05-060, mimeo., pp. 28-29).

ECG questions the implementation of the deferral method as proposed by the utilities. ECG says that the utilities ignore the tax deductibility of interest expense, which results in a discount rate which is too high by about 1.8% and thus overstates the ramped capital costs. According to ECG, the utility implementation (1) delays the apparent cost-effectiveness of baseload and intermediate plants, and (2) causes ratepayers to overpay capital costs by about 4% each year.

Edison's rebuttal is succinct. ECG, according to Edison witness Jurewitz, "fails to recognize that the income tax component of utility revenue requirements already incorporates the interest expense deduction. Thus, the incremental cost of capital calculated by Edison represents the return on investment required by investors, already taking into account the tax deductibility of interest expense." (Exhibit 424, p. II-13.)

We agree with Edison that the tax deductibility of interest expense is considered in determining utility revenue requirements. Furthermore, the utilities appear to have used formulas here that are consistent with present practice for calculating revenue requirements. It seems from the prepared testimony and cross-examination that the question is not whether but how the tax deductibility of interest expense is to be accounted for. However, ECG also has a point in that the method used for factoring certain fractions into the formula can affect the bottom line.

For present purposes, i.e., determining avoided cost payments for deferring/avoiding a utility resource, we approve the implementation of ramped payment streams as proposed in the utilities' compliance filings. This is because these filings are consistent with the derivation of the utilities' own revenue requirements and thus preserve ratepayer indifference as between QFs deferring a given resource and the utility acquiring it.[14]

III. Energy Pricing for QFs with Variable Energy Payments

One of the main issues in the consolidated standard offer proceeding concerns the calculation of energy prices for QFs whose contracts provide for variable energy payments.[15] Such QFs are

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14 Our conclusion here does not preclude a separate investigation of the treatment of taxes in calculating utility revenue requirements. We recognize the importance of this subject, but it is beyond the scope of the present proceeding.

15 "Variable energy payments" are those that we recalculate periodically, based on our latest projections of the price of the marginal fuel and of the incremental energy rate (IER) for each utility. (The IER reflects the utility's use of thermal energy in producing electricity at the margin; generally, the marginal unit of electricity is generated by burning oil or gas, but the CPUC's energy pricing method also recognizes periods when, e.g., non-

(Footnote continues on next page)

primarily on the short-run standard offers (Standard Offers 1, 2, and 3) but also include interim Standard Offer 4 QFs at the end of the fixed price period, certain QFs under nonstandard contracts, and final Standard Offer 4 QFs that come on-line during Period 1 (i.e., before the on-line date of the deferred resource). We conclude that the calculation method known as "QFs-in/QFs-out," which we have previously approved for final Standard Offer 4 QFs during Period 1 (D.85-07-022), and for pricing short-run QFs on the SDG&E and PG&E systems, should be used at this time for all utilities and all QFs receiving variable energy payments. However, we reject arguments that QFs-in/QFs-out is required by federal law, and we are willing to consider changes to our ECAC balancing account procedure that may justify marginal cost pricing (i.e., QFs-in) for QFs on short-run contracts.

A. <u>The Basics of QF Energy Payments</u>

All parties would use the same basic components to calculate variable energy payments to QFs; what is under debate here is the derivation of one of the components, the IER.

(Footnote continued from previous page)

oil/gas fuels or power purchases are on the margin, and reduces the utility's IER accordingly.) Marginal fuel prices have been updated quarterly since the beginning of our QF program. In our final compliance phase decision, we plan to adopt a new updating procedure that continues the quarterly revision of marginal fuel prices and institutes at least an annual revision of the IERs.

Some QFs (e.g., final Standard Offer 4 QFs during Period 2, interim Standard Offer 4 QFs early in their contracts) receive "fixed energy payments." By this term, we mean simply that at least the IER used to calculate such a QF's energy payments is established by contract for some period longer than the update cycle we use for recalculating the bases for variable energy payments.

Under all of the various QF contracts that we mentioned above, the QF gets paid on a cents per kilowatt-hour basis for energy that it generates and delivers to the grid. The payment essentially results from a two-part formula. One part is the purchasing utility's IER, which is its incremental efficiency in converting heat energy to electricity and which is expressed as British thermal units (BTUs) per kilowatt-hour. The other part is the cost of the purchasing utility's marginal fuel, typically oil or gas. This part is expressed as dollars per million BTUs. Multiplying the IER by the fuel cost gives the cents per kilowatt-hour that the purchasing utility pays for the QF's output.[16]

The formula worked quite smoothly for the first few years of the QF program. Currently, there is controversy that affects both parts of the formula due to recent changes in circumstances. The calculation of marginal fuel cost is complicated by major changes in CPUC gas rate design policies set in motion by D.86-12-009. We are now completing the implementation of that decision and have set hearings (to begin on February 22, 1988) on the issue of gas costs avoidable by QFs.

The calculation of incremental efficiency was also easy as long as QFs were a very small part of a utility's resource mix: if QFs account for relatively few kilowatt-hours, all parties agree that the generation efficiency of the last kilowatt-hour dispatched from the utility's own resources is a reasonable approximation of what the utility would do in the QFs' absence. The problem that we address here is how to calculate the IER when (as is now the case)

16 The cents per kilowatt-hour figure is then time-differentiated to reflect the purchasing utility's variation in marginal running costs at different times of day and seasons of the year. Time-differentiation serves to give accurate price signals to QFs and to maintain ratepayer neutrality in having energy generated by the QF rather than by the utility.

QF output is much greater, both proportionally and in absolute terms, so that QFs in effect back down many different utility resources, with potentially many different efficiencies.

B. Computer Runs and Variable Energy Payments

Our discussion uses the terms "QFs-in" and "QFs-out" to describe two kinds of computer runs that represent the operating efficiency of any given utility system by means of a production cost simulation model. As their names suggest, the only difference between the two runs is in the treatment of QFs. The QFs-out run represents the projected dispatch of the system with all variably-priced QFs removed. The QFs-in run represents system dispatch including all variably-priced QFs anticipated to be on-line during the forecast period. Finally, the term "QFs-in/QFs-out" refers to the average of the IERs calculated by performing the two runs for a given utility system.

C. Arguments for QFs-in (Marginal Cost Pricing)

As QFs are added to a utility's system, that utility is able to turn off its less efficient, higher running-cost plants an increasing proportion of the time. In other words, the utility's IER drops. The present debate concerns what IER to use in calculating variable energy payments: an IER representing the utility's efficiency for the last unit of electricity actually dispatched (QFs-in); or an IER representing the utility's average efficiency in replacing QF power--i.e., the utility's avoided cost measured over the whole block of short-run QF output--if the utility itself had to generate the electricity delivered to its system by these QFs (QFs-in/QFs-out).

PG&E and Edison support the QFs-in approach.[17] They say that QFs-in more closely simulates a competitive "spot" market price. They note that, as the number of short-run QFs selling to a particular utility grows, the difference between the QFs-in and the QFs-in/QFs-out IERs grows proportionally, and they claim that using QFs-in results in lower costs to ratepayers. Finally, they believe that QFs-in correctly interprets the directive in federal regulations that sales of QF energy be priced at the purchasing utility's avoided costs.

These utilities also caution that under certain circumstances, QFs-in/QFs-out does not realistically reflect what a utility would have done to replace short-run QF power. The potential distortion occurs because QFs-in/QFs-out is predicated on dispatch of the utility's existing system; however, at some point, consistent with prudent long-run planning, the utility would add a new, more efficient resource (resulting in a lower IER than that suggested by QFs-in/QFs-out) rather than just running its existing system harder. The likelihood of such distortion increases with the number of short-run QFs. PG&E and Edison concede that the refinements to QFs-in/QFs-out proposed by DRA and by SFG/U/F might

17 However, PG&E and Edison use different methods to calculate the QFs-in IER. PG&E seems to have in mind its instantaneous marginal rate, which appears to be equivalent to what some parties refer to as "system lambda." Edison uses a "zero-intercept" calculation that accounts for certain start-up and other operational costs resulting from a change in loads and not reflected in system lambda. The consensus of commenters is that Edison's method, compared to PG&E's, is less sensitive to minor variations in assumptions, and PG&E has indicated that it is willing to consider the method for its own use. We do not adopt a QFs-in method at this time; however, the advantages of the zero-intercept calculation seem clear. PG&E should be prepared to explain any reason for not adopting that calculation at such time as we revisit the variable energy payment issue.

mitigate this problem, but they believe that the refinements (1) are hard to implement, and (2) do not provide the advantages claimed for the QFs-in method.

D. <u>Arguments for QFs-in/QFs-out (Incremental Cost Pricing)</u>

DRA and QF representatives say that short-run QFs are entitled under federal law to be paid for energy according to the costs that a utility would have incurred "but for" the energy delivered by these QFs. The QFs-in/QFs-out IER calculation accurately measures such costs. QFs-in allegedly undervalues short-run QFs because the utility can recover its full cost of replacing QF deliveries, should these fall short of the quantity estimated for purposes of calculating the QFs-in IER. Thus, the benefits claimed for ratepayers under QFs-in are illusory.

DRA and QF representatives note that the electric utility continues to occupy an essentially monopsonistic position in this market. They believe that QFs-in, rather than promoting competition, strengthens the utility monopsony because only the QFs have to compete at the QFs-in price, while the utility in case of need can dispatch less efficient resources and still recover its excess costs through ECAC.

SFG/U/F (supported by IEP) and DRA believe that QFs-in/QFs-out does not appropriately price short-run QFs' energy deliveries under all circumstances. At some point, a utility will incur energy-related capital costs to add a new resource (in order to lower its operating costs) rather than run its existing system harder. These parties would all modify the QFs-in/QFs-out method to provide a cap on variable energy prices whenever a utility has so many short-run QFs on its system that it would substitute a new resource to lower its operating costs if all these QFs were removed from its resource plan.

These parties present two different proposals for identifying "substitute" resources. However, the purpose of the proposals is identical: to arrive at a continuously optimized resource plan for each utility, such that short-run QFs in each year receive energy prices that reflect an optimal mix of existing and "substitute" resources, based on the latest Commission-adopted planning assumptions.[18] As these parties note, such optimization is possible for a utility only by virtue of having QFs on its system.

SDG&E generally supports using the QFs-in/QFs-out method but also believes that the method could give improper price signals if large amounts of QF power are being purchased. That is not presently the case for SDG&E's system, and SDG&E recommends that the method not be modified until an actual situation illustrates why modification is warranted.

E. Discussion

1. Final Standard Offer 4 QFs in Period 1

Final Standard Offer 4 QFs are allowed to come on-line in Period 1, i.e., before the projected on-line date of the utility resource that such QFs defer or avoid. During Period 1, such QFs are not paid based on the deferrable resource but instead are to receive capacity payments based on the purchasing utility's then-current shortage costs and energy payments based on the QFs-in/QFs-out method. (See D.85-07-022, mimeo., pp. 54-56.)

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18 "Avoidable" resources are those that a utility would add with all its existing resources shown in its resource plan; "substitute" resources are those that a utility would add with short-run QFs removed from its resource plan. If an avoidable resource is identified, it becomes the basis of a final Standard Offer 4 auction and may be built if not deferred through the auction; if a substitute resource is identified, it would not be built but becomes the basis for limiting energy prices paid to short-run QFs. Essentially, substitute resources are a device for ensuring that the presence of a large number of short-run QFs in a utility's resource mix does not result in the uneconomic displacement of attractive long-run resources.

The debate in the compliance phase is not over the propriety of this treatment of final Standard Offer 4 QFs during Period 1, but rather whether the treatment should be extended to include all QFs receiving variable energy payments, as D.85-07-022 and D.86-07-004 (see pp. 77-78) suggest. In today's decision, we adopt a more qualified endorsement of the QFs-in/QFs-out method of short-run energy pricing, so it is important to make clear that, regardless of the pricing method for other QFs receiving variable energy payments, QFs-in/QFs-out remains appropriate for final Standard Offer 4 QFs in Period 1.

The reason for this distinction is that even in Period 1, a utility system has increasing operating costs that will eventually justify a commitment of capital (so-called "energy-related capital costs") to improve system efficiency. Final Standard Offer 4 QFs, but not others, are specifically designated to defer or avoid investments with energy-related capital costs; the payment stream to final Standard Offer 4 QFs in Period 1 should therefore reflect the cost characteristics of the utility system that are projected to justify the addition of the deferrable resource at the start of Period 2. This is exactly what the QFs-in/QFs-out method does.

2. Substitute Resources

Everyone now accepts the premises (1) that a prudent utility would not continuously add short-run QFs, or other short-run resources, and thus (2) that the QFs-in/QFs-out method could at some point produce unrealistic results because it relies on modeling the dispatch of the utility's existing system. In theory, the method should therefore be modified to somehow account for any long-run resources that a utility would substitute for short-run QFs if they were all removed from its system.

We will not adopt at this time either SFG/U/F's or DRA's suggested modifications. There are at least three reasons for this decision.

First and most important, short-run QFs, although their absolute numbers have increased enormously since the start of the QF program, are still a very small part of the utilities' resource mix. No party has said that substitute resources would be found now if the utilities were to conduct a resource plan analysis of their QFs-out runs; and several parties, such as SFG/U/F and the California Cogeneration Council, have testified that the problem is likely to remain entirely theoretical at least until the late 1990s, when large numbers of interim Standard Offer 4 QFs reach the end of the fixed energy price periods in their contracts. The record seems to support these parties.

Second, both of the suggested modifications involve fairly complex and hypothetical manipulations of utility resource plans. We agree with SDG&E that it is wise to gain more experience with the biennial resource planning process before making new demands on that process.

Third, as we discuss below, we may change the basis for calculating variable energy payments to QFs other than final Standard Offer 4 QFs in Period 1, depending on possible changes to the ECAC balancing account procedure. Thus, the need to modify the QFs-in/QFs-out method may never arise.

3. <u>Marginal vs. Incremental Cost Energy Pricing</u>

This brings us to the heart of the matter. Specifically, we must decide on the method of calculating variable (short-run) energy payments that is consistent with our current regulatory policies and with state and federal laws and regulations on avoided cost pricing.[19]

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19 The federal Public Utility Regulatory Policies Act (PURPA) and the California Private Energy Producers Act supply the statutory context for the development of avoided cost pricing. Also, the

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As we interpret this body of law and policy, the purpose is to create a pricing structure that captures to the extent possible the efficiency and other benefits of perfect competition in electricity generation.[20] It seems logical under such conditions that a buyer (whether for the buyer's own use or for resale) would purchase electricity offered at a price that is lower than the buyer's own cost to generate an equivalent amount of electricity. Also, the buyer would continue to make purchases up to the price at which it could otherwise get the offered electricity at the same or lower cost. Everybody benefits: the buyer(s) by minimizing costs, the seller(s) by generating at a profit, and society at large by efficiently allocating its resources. Unfortunately, <u>neither</u> QFs-in nor QFs-in/QFs-out will fully capture these benefits under existing conditions.

QFs-in/QFs-out does not give an accurate price signal as to the value of <u>additional</u> energy deliveries by QFs. The method prices short-term energy based on the utility's average cost to replace projected QF deliveries through other generation resources available to the utility. As such, the method truly represents the value to the utility of the increment of QF deliveries projected for the forecast period. However, the last generation resource

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Federal Energy Regulatory Commission has adopted regulations implementing PURPA (FERC regulations), and all of these authorities have been interpreted in the extensive body of CPUC decisions on QF matters. (See generally D.86-07-004 and the decisions cited in Appendix C of that decision.)

20 We emphasize "perfect" competition because we doubt that many markets in fact behave as theory predicts, and because state and federal law do no more than loosely approximate a competitive market in electricity: for example, the utilities retain their monopsony position virtually untouched.

backed down is likely to be cheaper than that average cost, so the utility may be required in some circumstances to pay a price to QFs that it would not pay in a true "spot" market because the utility would prefer to run its own plant.[21]

The problems with QFs-in are worse. While QFs-in/QFs-out gives an inaccurate signal on the value of additional energy deliveries by QFs, QFs-in prices all short-run energy deliveries as if the utility could replace such deliveries at its so-called marginal cost. There are at least four powerful objections to this.

First, if the projection of loads and resources for the forecast period is otherwise accurate, the utility would <u>not</u> be able to replace a shortfall in QF energy deliveries at a cost less than or equal to the QFs-in price. Depending on the timing of that shortfall, the utility might have to dispatch plants significantly more expensive than the running costs of the marginal resource in the QFs-in run.

Second, the utility does not have to absorb the increased energy costs just described. Those costs are picked up almost entirely by the utility's ratepayers. This is because the ECAC balancing account presently flows through to ratepayers almost all

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21 Whether the result would be overpayments or underpayments to QFs is less clear. If QF deliveries for the forecast period are less than projected, then QFs receiving variable energy payments would actually be underpaid. The problem is that QFs deciding whether to develop new short-run projects or increase deliveries from existing short-run projects would be making their decision based on an average avoided cost, not a marginal cost. Oil and gas prices are currently very low, so the practical impact of this distortion may be slight; the impact is likely to increase proportionally as fuel prices rise.

of the utility's energy costs in excess of those forecast, subject only to reasonableness review.[22]

Third, because of the factors we have just noted, QFs-in gives the utility an enormously powerful tool with which to exploit its monopsony power. Under QFs-in pricing, the utility can pursue a deliberate policy of getting rid of QFs simply by forecasting excessive QF deliveries, thus depressing the IER on which the energy price is based.[23] ECAC insulates the utility from the economic consequences of such a policy; furthermore, unlike weather-related uncertainty, there is no assurance that forecast error resulting from bias will cancel out over time.[24]

Fourth, we don't think that QFs-in equates to marginal cost pricing, even though PG&E and Edison say it does, and though we ourselves have referred to it as such for convenience. Fundamentally, QFs-in identifies the last kilowatt-hour dispatched from non-QF resources on a utility system under a given set of load and resource assumptions. That last kilowatt-hour could be generated at a cost equal to or higher or lower than the utility's marginal cost as determined in a competitive market. Nobody knows

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22 The only qualification to this generalization is that the utility is at risk for a portion of its energy costs by virtue of the Annual Energy Rate. This rate varies among the utilities but in each case represents a small fraction of the expenses subject to balancing account treatment.

23 The utility has a similar incentive under QFs-in/QFs-out but not nearly to the same degree because the averaging of IERs dilutes the impact of erroneous forecasts.

24 Without PURPA and the other legal requirements cited earlier, a utility could refuse to purchase QFs' deliveries or prefer its own more expensive generation only at some economic risk to itself. Thus, in some ways, the interaction of ECAC with QFs-in enables the utility to wield its market power over QFs even more effectively than it could before the passage of PURPA.

which, because the electricity market is far from perfect.[25] A competitive market is characterized by many buyers and sellers, many types of purchase contracts (some of them for terms of days or even hours), and most importantly, price-based decisions to produce or to purchase a particular good. In particular, the economically rational buyer in a competitive market will maximize the buyer's wealth by making all attractively priced purchases, and would lose wealth by foregoing such purchases. None of these conditions now exists in the electricity market generally or for the utility buyer of QF power. In fact, as ECAC presently works, some degree of market failure is institutionalized.

Thus, while conceding that good arguments support QFs-in as the basis for variable energy payments, we think that QFs-in/QFs-out is clearly preferable given the current industry structure.

4. <u>Consistency with PURPA</u>

PURPA and the FERC regulations generally require that the rate paid by a utility for QF power equal the utility's avoided costs. These are defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." (18 CFR §292.101(b)(6).) In determining avoided costs, the state regulatory authority is required to consider numerous factors as well as data provided by the utility. (18 CFR §292.304(e).)

25 Furthermore, it is only in the long-run equilibrium state of a perfectly competitive industry that the cost of producing the last unit of output would equal the price paid by consumers for that unit. In contrast, utility electric rates to end-users are based on <u>average</u> system costs.

We think that PURPA and the FERC regulations give the states some latitude to determine avoided costs; in other words, there is no neat formula for calculating avoided costs. The touchstone is always that the rates for utility purchases (1) be "just and reasonable to the electric consumers of the electric utility and in the public interest" and (2) "not discriminate against [QFs]." (See PURPA §210(b), emphasis added.)

The QFs-in/QFs-out method for calculating short-run energy prices seems consistent with the PURPA avoided costs standard. The method determines a price for an increment of QF deliveries, and FERC defines avoided costs as incremental, not marginal. Also, given our ECAC procedure, QFs-in/QFs-out truly reflects the costs that ratepayers see "but for" deliveries from short-run QFs.

However, it does not follow that federal law precludes the QFs-in method. We believe the state regulatory authority has the ability under PURPA to take into consideration the kinds of factors that we analyzed in Section III.D.3 above and to reach a different conclusion on avoided costs when conditions in the electric industry change.

PURPA was passed primarily to counteract electric utilities' exploitation of their market power to restrict development of potential electric generation by non-utility entrepreneurs. That purpose would be thwarted by having QF output priced at a so-called marginal cost that the purchasing utility did not have to meet or beat. Correspondingly, if ECAC were changed such that the purchasing utility were at risk in making up for any shortfall in QF deliveries at the utility's stated marginal cost, then it might very well be appropriate in a subsequent biennial update to revisit the question of QFs-in as the basis for variable energy payments.

Changes to ECAC, of course, should be considered in an ECAC proceeding or in our rulemaking to revise electric utility ratemaking mechanisms (R.86-10-001). Furthermore, we cannot specify in advance the kinds of changes necessary in order to put the utility "at risk." We would have to weigh proposed changes carefully to ensure that they are consistent with our overall policies as well as with the QF program. On the other hand, the utilities themselves have indicated a desire to position themselves competitively to respond to problems such as uneconomic bypass; to the extent that ECAC flows through automatically some amount of fuel expense that is susceptible to management control, ECAC contributes to the bypass problem, and the utilities would actually be better off by foregoing such balancing account treatment.

In short, the QFs-in/QFs-out method meets the PURPA requirements for QF pricing. To the extent that changes in ECAC and possibly other developments create a more competitive environment and move this industry closer to a true spot market, it is appropriate and consistent with PURPA to reconsider marginal energy cost pricing for short-run QFs.

IV. Standard Offer 4 Milestone, Contract Drafting Issues

A primary function of the standard offers is to reduce the transaction costs of creating power purchase agreements between utilities and QFs. By previously approving the terms and conditions of standardized contracts, the Commission speeds the process, helps to ensure its fairness, and enables QF and utility negotiators to focus on those areas where nonstandard provisions may benefit both parties to the agreement.

The development of final Standard Offer 4 provides many challenges and opportunities for contract drafting. Final Standard Offer 4 has many unique provisions and requires adaptations to the QF Milestone Procedure. Also, the QF Milestone Procedure was created outside of the standard offer development process, and so the procedure has existed as a separate document from the power purchase agreements that it governs. This anomaly could be corrected for final Standard Offer 4 by incorporating the procedure in the contract form.

Another important goal is to achieve the highest possible degree of uniformity between the contract forms and terminology of the different utilities. This would ensure evenhanded treatment of QFs throughout the state, while allowing such variation as might be compelled by the particular circumstances of individual utilities.[26]

The Commission has felt that all of these goals could be advanced through consultation among the parties in an informal setting, leaving fewer disputed areas for adjudication. The parties bring to such consultation an impressive range of expertise and experience with existing power purchase agreements. Discussions among these parties seems both preferable to weeks of hearings and likelier to produce technically sound solutions that everybody could live with.

A. Summary of the Negotiations

The task was enormous. We cannot discuss the finished product of this contract drafting effort without first acknowledging and expressing our appreciation for the work that went into it.

D.86-07-004, ordering paragraph 1.b, directs the utility applicants to amend their applications to include final Standard

26 Workshops were held earlier in this proceeding to develop uniform contract language for the other standard offers. One of our tasks following the final compliance phase decision is to review the agreements from these workshops for possible CPUC approval. As we discuss in Section II.C.2 of the second interim opinion in this phase, some of the products of the final Standard Offer 4 contract drafting may also be appropriate for other standard offers; ordering paragraph 5 of that decision solicits comment on this point.

Offer 4 contract forms, making maximum use where feasible of provisions from the other standard offers.

On October 31, 1986, the utilities served their compliance filings, including proposed contract forms. On November 21, 1986, SFG/U/F served rebuttal testimony that contested many utility-proposed provisions and included its own proposed contract form. IEP supported SFG/U/F's rebuttal testimony.

At hearings on non-resource planning issues held in December 1986, the ALJ urged the parties to hold workshops to try to resolve the areas of dispute or at least to reduce the number of issues for hearings starting in June 1987. The utility applicants, DRA, IEP, and SFG/U/F held workshops from early January on, for a total of 18 days during the next five months. Also, SFG/U/F and Edison met for several more days during this period to draft language as areas of agreement were reached. At the end of May, workshops had resulted in agreement on a uniform final Standard Offer 4 contract as to all but 10 areas of disagreement and two areas (curtailment and power sales at the end of Period 2) on which discussions were deferred due to time constraints.

On May 29 and June 1, 1987, the parties served testimony on the areas of disagreement. Also, PG&E served testimony on five areas for which it sought utility-specific variations from the agreed-on provisions.

On the first day of the June hearings, the parties suggested that further workshops might resolve some remaining areas of disagreement. The ALJ authorized workshops to continue, and the parties met for four more days, ending July 2, 1987. There was one more meeting between SFG/U/F and Edison to finalize contract language on areas of agreement.

At this point, the parties to the workshops (other than PG&E and IEP) had achieved agreement on <u>all</u> issues. The Joint Testimony served on July 10, 1987, sets forth the agreement among the parties and identifies areas that remain disputed by PG&E and

IEP. (PG&E still has four objections, while IEP has one.) The Joint Testimony presents a complete final Standard Offer 4 contract form for the Commission's review.

B. <u>Contract Provisions of Final Standard Offer 4</u>

As summarized in the Joint Testimony (Exhibit 447), the parties have followed the Commission's directive to use, where possible, provisions previously approved for use in other standard offers. Thus, the parties based their agreements on the uniform version of interim Standard Offer 4, with appropriate changes to account for the different basis for calculating avoided cost in final Standard Offer 4. The parties have also incorporated new provisions such as Project Development Milestones (thus avoiding the potential confusion resulting from a discrete QF Milestone Procedure not contained within the four corners of the contract), Abandonment, Power Sales at End of Period 2, and liquidated damages.

The Joint Testimony explains that, where the parties have modified previously existing standard offer contract provisions and added new provisions, they did so to accommodate the differing nature of final Standard Offer 4. They say (and we agree) that the latter offer involves both a greater degree of discipline in the obligations of the QF, especially in development stages, and a greater degree of utility cooperation with the QF. Thus, the contract generally reflects a high level of commmunication and information between the utility and the QF, and a balancing of rigorous development milestone requirements with appropriate flexibility and reduced development risk.

Generally, the parties also stress that the agreed-on provisions represent a whole series of compromises and tradeoffs to reach a balanced, equitable agreement. On that basis, the parties "cannot emphasize too strongly that deviations in one or more isolated positions will tend to upset that balance and likely yield an agreement which is not evenhanded and on which agreement could not have been reached." (Exhibit 447, p. 2.)[27]

C. A Valediction

The above summary barely hints at the magnitude and the significance of the achievement marked by the Joint Testimony. Final Standard Offer 4 is the most ambitious standard offer we have ever attempted. Something of this is suggested by the sheer size of the contract form, which runs to over 100 pages plus appendixes. Much more impressive is the effort involved in giving linguistic expression to complex formulas. The parties have not only met this challenge, but have produced a document that is easy to follow and even, with allowances for the technical nature of the subject, easy to understand.

No contract form can be so meticulous as to wholly forestall later disputes on the meaning of the agreement, particularly in a case like this, where the subject of the agreement is complex and the economic stakes are high. Nevertheless, this joint effort has brought to bear a wealth of experience (some good, some bad) under other standard offers and has fostered a common understanding and an atmosphere of cooperative problem-solving that should result in fewer and more easily resolved disputes.

The mass and detail of the contract form again recall the significance of the standard offer in reducing transaction costs. Negotiating this contract would overwhelm the capabilities of a small QF. We suspect that case-by-case negotiation of such contracts would severely strain even large QFs and the utilities

27 In deference to this view, IEP did not sponsor the Joint Testimony but has indicated that it takes issue with that testimony in only one respect. PG&E did sponsor the Joint Testimony, although it requests different provisions specific to PG&E in four respects.

themselves. Even nonstandard power purchase agreements are helped because the parties to such agreements may be able to use most of the standard provisions and thus to concentrate their efforts on project-specific provisions (e.g., additional performance features) that would benefit both seller and utility.

We think that the final Standard Offer 4 contract form is one of the outstanding achievements in the evolution of the QF industry. That the contract form is the product of a cooperative effort of utilities, QFs, and our own staff, marks the further maturation of the QF industry. As we have often said, the full integration of QFs in utilities' resource planning requires that QF/utility discourse occur more often at the bargaining table and less often in our hearing rooms.

For all these reasons, we are delighted with the product of this negotiating effort. All the participants in that effort--Edison, IEP, PG&E, SDG&E, SFG/U/F, and DRA--have earned our thanks and congratulations.

D. Issue Deferred for Later Resolution

One area put at issue in testimony served before the Joint Testimony relates to the capacity factor assumed for the avoidable resource. Some parties would fix this factor for the duration of the contract at the time the resource is identified; other parties would make some provision for updating this factor.

The parties basically ran out of time to deal with this issue. They jointly request that we approve the final Standard Offer 4 contract as presented in the Joint Testimony, while deferring the capacity factor issue to the next round of utility resource plan filings.

This request makes good sense. In the absence of an avoidable resource for any of the utilities at this time, we feel no urgency in addressing this issue. We accordingly defer this issue to the biennial update proceeding. We of course encourage the parties to discuss the issue before that proceeding, and to present any negotiated resolution for our consideration at that time.

E. Agreement in Principle on Curtailment Provision

The Joint Testimony says that the parties have reached agreement (with one qualification by PG&E that we will discuss later) on the general terms of a provision under which the purchasing utility could curtail a QF's output pursuant to one of two options (to be elected by the QF at the time it executes the final Standard Offer 4 contract). Option I allows the utility to curtail for a negative avoided cost or hydro spill condition, without any limits on frequency, duration, or number of curtailments. Option II allows the utility to curtail at its sole discretion for up to 1500 hours annually, during off-peak and super off-peak periods, with a minimum duration of three hours.[28]

The parties request that the Commission approve these curtailment terms and direct the parties to continue workshops to draft the specific language for the curtailment provision. These workshops are needed because agreement in principle was reached too late in the negotiations for detailed consideration of wording to fit all aspects of administering the agreed-on terms.

We strongly endorse the concepts of the proposed curtailment provision. It is another step in the integration of QFs in utility system operation. Moreover, it achieves this through use of flexible operating and pricing terms that recognize the diversity of QFs rather than trying to force all QFs into a single rigid mold. We approve the proposed curtailment provision in principle and direct the parties to complete the drafting of the provision in further workshops. We are also considering including such a provision in Standard Offers 1 and 2. Accordingly, we will

28 See Appendix A of Exhibit 447 for a detailed summary of the curtailment terms.

review as soon as it is available the specific language for the curtailment provision that is developed at the workshops.

F. <u>Provision Disputed by IEP</u>

IEP disagrees with the Joint Testimony's treatment of capacity payments to as-available QFs. Under that treatment, such capacity payments would be limited to a level equivalent to the effective capacity of the QF. IEP would delete this limitation.

As-available QFs are those which cannot or do not wish to commit to provide firm capacity. Often, such QFs use a weather-dependent technology (e.g., wind, hydro). For planning purposes, the purchasing utility converts the nameplate capacity of such QFs to some fraction, designated the "effective" capacity, which is presently derived from aggregate historical performance of QFs using the same technology, and which (together with bid price) is the basis for allocating final Standard Offer 4 contracts to such QFs.

IEP says the limitation systematically underpays as-available QFs. For example, a wind QF with highly reliable equipment will often outperform the average wind QF but will never have that superior performance recognized in its capacity payment.

The justification for the Joint Testimony's treatment (as explained by Edison) is that final Standard Offer 4 prices are predicated on deferral or avoidance of specific resources. The utility can only defer resources equivalent to the long-term effective capacity of as-available QFs signing that offer; the utility cannot defer resources based on temporary levels of capacity produced by as-available QFs that exceed effective capacity. In short, QF capacity is only as valuable as the capacity that the utility can defer as a result of the QF's commitment.

We find that, while there are sound arguments on both sides, Edison's arguments are more persuasive in the context of final Standard Offer 4. We also give some weight to the parties' representation that the Joint Testimony's recommendations must be treated as a balanced whole. Parties to a settlement need room to compromise on issues; no such room exists if the settlement must resolve each issue in exactly the same way as if the issue had been litigated in full. We have concluded that the Joint Testimony's uniform final Standard Offer 4 contract provisions, taken as a whole, are reasonable and in the public interest. That reasonable people might differ on some of the provisions does not negate our conclusion.

G. Provisions Disputed by PG&E

PG&E believes that certain of the agreed-on provisions are unreasonable, at least as applied to its own system. We have allowed some variation between utilities in their respective standard offer provisions (e.g., on QF size for purposes of the telemetry requirements) where a utility-specific need is demonstrated. However, we do not believe that PG&E has made a convincing showing on any of the disputed provisions.

1. Firm Capacity Demonstration Test

The dispute is that PG&E proposes a firm capacity demonstration test that requires the QF to operate at 100% of its firm capacity commitment level for at least 80% of the hours over 30 consecutive days, while the Joint Testimony, in which Edison and SDG&E concur, has a less stringent test, i.e., operation at 80% or greater capacity level for 30 days.

PG&E fails to show, either that the less stringent test is technically inadequate, or that conditions on the PG&E system require the more stringent test. PG&E simply says the latter test is "not unreasonable." (Concurrent brief, p. 65.) It well may be "not unreasonable" but that does not persuade us to prefer it to a technically adequate test that is acceptable to the other parties. We reject the PG&E proposal.

2. Surplus Sale Option

PG&E would require the final Standard Offer 4 QF either to sell its net output to PG&E or to use some of the generation on-site and sell the surplus to PG&E. Retail sales to neighboring end-users would not be permitted.

PG&E concedes that retail sales to neighboring loads are permitted when made by QFs operating under other standard offers or nonstandard contracts. Moreover, the Public Utilities Code expressly exempts cogenerators and users of unconventional power sources from public utility status even though they make certain retail sales to neighboring loads. PG&E invokes current concerns about system bypass to justify its proposal. However, QFs operating under final Standard Offer 4 seem very unlikely to contribute to uneconomic bypass. This is because final Standard Offer 4 contracts only become available when the utility's resource plan shows a need for baseload or intermediate capacity. PG&E's position is untenable.

3. Emergency Availability

During a system emergency, the utility generally prefers that, so far as possible, generation sources remain connected to the grid and continue energy deliveries. This helps to stabilize the system, while unnecessary separation could exacerbate an abnormal system condition.

The emergency availability provision recommended in the Joint Testimony says that "Seller [i.e., the QF] shall use reasonable efforts to deliver energy during periods of Emergency at an average rate of delivery at least equal to the Effective Capacity. If Seller has previously scheduled an outage which coincides with an Emergency, Seller shall use reasonable efforts to reschedule the outage. If Seller reschedules the outage pursuant to this Section, [utility] shall waive the notice periods for scheduled outages...." (Emphasis in original.)

PG&E's version has an additional requirement, which PG&E inserts between the first and second sentences of the Joint Testimony's provision: "[I]n the event of a PGandE electric system frequency or voltage excursion which exceeds the normal limits of regulation, but does not cause the Protective Apparatus to automatically separate the Generating Facility from the PGandE system, Seller shall not manually separate its Generating Facility from PGandE's system without first notifying and obtaining permission from the PGandE Designated Switching Center. Such permission shall not be unreasonably withheld. Seller shall not alter settings of the Protective Apparatus from the settings established during the pre-parallel inspection." (Emphasis in original.)

The concern that QFs seem to have with PG&E's version is that the version could effectively require the QF to sustain damage to its plant if the relays either do not function or are set at levels sufficient to protect PG&E's equipment but not the QF's equipment. (See cross-examination of PG&E witness Di Pastena by SFG/U/F, Tr. 7971-74.) For example, we think it probable that a utility switching center in an emergency would have higher priorities than to determine whether the relays at a five megawatt QF plant were malfunctioning, even though the consequences to that QF might be serious.

We think that, under a fair reading of the Joint Testimony's emergency availability provision, the QF is already required to continue to deliver energy if it can do so without harm to its equipment. What seems to underlie PG&E's wordsmithing is a concern that some QFs separate from the system even when the frequency or voltage excursion, at least in PG&E's opinion, is not so great as to endanger the QF. However, from the QFs' viewpoint, PG&E is demanding the right to make the final decision on a matter affecting the safety of the QFs' personnel and equipment.

We are satisfied with the approach taken in the Joint Testimony. We also feel strongly that appropriate QF response to emergencies is vital if utilities are to rely on large amounts of QF power. The Joint QF/Utility Consultative Committee that is getting underway offers a suitable forum to discuss technical problems and possible improvements in communication between the utility and QF during emergencies. PG&E should pursue this topic in the committee, particularly since, as PG&E notes, the thousands of QF megawatts already under contract with PG&E are not subject to the type of emergency requirement that PG&E seeks here.

4. Curtailment

As we mentioned in Section IV.E above, PG&E qualifies in one respect its endorsement of the Joint Testimony's curtailment provision. PG&E's support of the 1500 hour curtailment option is conditioned on our determining that the IERs used for PG&E's energy prices should be updated on a quarterly basis. If we do not accept PG&E's update proposal, then PG&E would oppose including in its final Standard Offer 4 an option to limit curtailable hours.

PG&E justifies its position on the basis that, unlike Edison and SDG&E, PG&E's system has a substantial quantity of hydro resources. Unless there is a mechanism for updating IERs frequently, and so capture the impact of various levels of expected hydro generation, PG&E says that the limitations of the 1500 hour curtailment option could result in energy payments above avoided cost.

We think PG&E's linkage of IER updating with curtailment options under the final long-run offer is inappropriate. First, curtailment is a contract drafting issue, while IER updating is not. Neither final Standard Offer 4 nor any other standard offer specifies any particular method for updating IERs. Second, and more fundamental, IER updating affects energy pricing for QFs with variable energy payments (see Section III.A above) but is largely irrelevant to energy pricing for final Standard Offer 4 QFs. For example, the energy payments to such QFs in Period 2 (the time after the avoidable resource would have come on-line) derive from either (1) an IER fixed when the contract is signed multiplied by the system marginal fuel cost or (2) the avoided plant's heat rate multiplied by the price of fuel that the plant would have consumed. (See D.86-07-004, pp. 79-80a.) The relevant updating for final Standard Offer 4 is the cost of fuel (which we do quarterly), <u>not</u> the IER.

PG&E Exhibit 453 posits, based on ER-6, that large amounts of non-oil/gas-fired generation will appear on the margin for PG&E in wet years by the late 1990s. This should not be a problem because the vast majority of PG&E's QFs, such as those operating under interim Standard Offer 4, have contracts that set no limit on PG&E's ability to invoke hydro spill pricing or negative avoided cost curtailment. The presence in final Standard Offer 4 of an option limiting curtailable hours is logical, considering that the offer is only made available when the utility's resource plan shows a need for baseload or intermediate capacity.

The most surprising part of PG&E's position is that, on the whole, the 1500 hour curtailment option seems preferable from a <u>utility</u> standpoint to the curtailment option limited to negative avoided cost or hydro spill conditions. The incidence of such conditions to date has been extremely low (zero for negative avoided cost), while in contrast the utility can require curtailment under the 1500 hour option whenever the utility finds it economic to do so. We think that the greater flexibility of the 1500 hour option easily outweighs the limit on curtailable hours. Possibly PG&E considers 1500 hours too conservative, given the quantity of hydro on its system; if so, PG&E should have made a utility-specific showing to justify a higher limit, e.g., 2000 hours, such as PG&E has negotiated for some of its existing QF contracts.

We find that Option II (the 1500 hour curtailment option) should be included in PG&E's final Standard Offer 4. We reserve to our final compliance phase opinion the question of quarterly versus annual IER updating.

H. Contract Implementation Requirements

The Joint Testimony outlines several steps that need to be taken in conjunction with approval of the final Standard Offer 4 contract form.

1. Allocation of Available Transmission Capacity

We grant the parties' request that each utility be authorized to submit, by advice letter filing, revisions to the respective utility's Tariff Rule 21 (governing QF-utility system interconnections) to provide for the allocation of available transmission capacity on the utility system.

The reason for this request is that final Standard Offer 4 incorporates milestones from the QF Milestone Procedure without providing for the allocation of available transmission capacity. The proposed tariff revisions would say in essence that, for a QF that (1) is not subject to the QF Milestone Procedure, and (2) wins a final Standard Offer 4 contract, entitlement to available capacity on the utility's transmission/distribution system and a priority to such line capacity is established as of the date that the QF's bid is determined to be a winner. The QF thereafter retains its entitlement and priority so long as it does not default in performance of its agreement.

We agree with the parties that the proposed tariff revision is an appropriate means to allocate transmission priority.

2. Other Revisions to Tariff Rule 21 (Edison, PG&E)

Edison and PG&E had included certain provisions in their final Standard Offer 4 compliance filings that the parties agree would more appropriately appear in the operating requirements manual (implementing Tariff Rule 21) of the respective utility.

avoided cost or hydro spill conditions. The incidence of such conditions to date has been extremely low (zero for negative avoided cost), while in contrast the utility can require curtailment under the 1500 hour option whenever the utility finds it economic to do so. We think that the greater flexibility of the 1500 hour option easily outweighs the limit on curtailable hours. Possibly PG&E considers 1500 hours too conservative, given the quantity of hydro on its system; if so, PG&E should have made a utility-specific showing to justify a higher limit, e.g., 2000 hours, such as PG&E has negotiated for some of its existing QF contracts.

We find that Option II (the 1500 hour curtailment option) should be included in PG&E's final Standard Offer 4. We address in our fourth interim compliance phase opinion the question of quarterly versus annual IER updating.

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The provisions in question set forth generating facility design and siting requirements.

We authorize Edison to file by advice letter appropriate revisions to its Tariff Rule 21 and, upon our acceptance of such revisions, to delete Sections 6.1(d), 6.1(e), 6.1(f), and 6.3(j) from its final Standard Offer 4 contract form. Of these four sections, only Section 6.3(j) applies to PG&E, and none of these sections applies to SDG&E. We authorize PG&E, as with Edison, to make the appropriate revision and deletion.

3. Utility-Specific Contract Provisions

The Joint Testimony generally sets forth its recommendations by reference to Exhibit 446, which is Edison's proposed final Standard Offer 4 contract form as of June 1987. That form has various provisions and terminology specific to Edison. Appendixes G and H to the Joint Testimony contain a list of utility-specific modifications to Exhibit 446 needed to adapt it for use by PG&E and SDG&E, respectively. The bulk of the modifications serve to correctly identify the purchasing utility and to be consistent with that utility's terminology. (E.g., SDG&E says "semi-peak" rather than "mid-peak.") We agree that PG&E and SDG&E, in conforming their final Standard Offer 4 contract forms, should make these modifications.

Findings of Fact

1. An EUE-based ERI method for valuing capacity was adopted in D.86-11-071. The method, as implemented by SDG&E and Edison, (1) produces reasonable results, (2) is reasonably consistent with capacity requirements projected by the CEC in ER-6, and (3) is suitable for use by these utilities in any proceeding before this Commission when projecting capacity need or valuing capacity already on or to be added to their systems.

2. The ERI method, as implemented by PG&E, does not produce reasonable results. A temporary capacity value adjustment is needed for use by PG&E for certain QF payments in 1988. A

reasonable adjustment would be to continue PG&E's 1987 as-available capacity price ($42 per kilowatt) through 1988.

3. Further comment is needed on how to make future capacity value adjustments for as-available QFs on PG&E's system. For long-term capacity planning purposes, use by the CPUC of the CEC's capacity requirements for PG&E (as projected in the CEC's most recent Electricity Report) would result in consistent treatment of different types of resource options. Reasonably consistent treatment is one of the chief goals of this proceeding and future resource plan updates.

4. The fact that a given type of generation resource, such as a peaking plant, is nondeferrable under D.86-07-004 does not by itself establish that such a resource can or should be included in a utility's resource plan. The utility must also show that the resource is cost-effective in order to justify such inclusion.

5. Standard Offer 2 and final Standard Offer 4 contain long-term fixed prices and accordingly require long-term forecasts. Such forecasting is done for the PG&E, SDG&E, and Edison systems in the biennial resource plan proceedings, so these proceedings are suitable for setting the fixed payments for these offers.

6. Because of the lack of avoidable megawatts for purposes of final Standard Offer 4 and the continued suspension of Standard Offer 2 for PG&E and Edison, the only long-term fixed prices that need to be established at this time are the capacity price schedules for SDG&E's Standard Offer 2.

7. Variable capacity payments to QFs (chiefly under Standard Offers 1 and 3) depend on short-term forecasts and should be updated annually. ECAC proceedings are well suited for such updating because they already involve the adoption of assumptions on the utility applicant's loads and resources during the one-year forecast period.

8. For 1988 only, Edison's variable capacity payments will be set in its current general rate case (Application 86-12-047), using the ERI method approved in today's decision.

9. SDG&E's variable capacity payments for 1988 will equal its annualized fixed costs of a combustion turbine.

10. SDG&E's capacity price table for reinstated Standard Offer 2 needs prices for two blocks of 50 megawatts each (effective capacity). Upon reinstatement, the blocks are to be available until the end of calendar year 1988 or until fully subscribed, whichever occurs first. Prices shown for the second block assume that all QFs from the first block are already on-line. The table is to contain capacity price schedules for each year in which this cohort of Standard Offer 2 QFs is allowed to come on-line (i.e., through 1993), and for all contract lengths to and including 30 years.

11. SDG&E's capacity price calculations for reinstated Standard Offer 2, as described in finding of fact 10, are to assume the refurbishment of Silver Gate but no other additional resources.

12. Reliability models have great and growing importance in CPUC proceedings. The on-going study of computer models pursuant to Assembly Bill 475 (Chapter 1297 of the 1985 Statutes) is the appropriate setting to develop information on the various types of reliability models.

13. "Variable energy payments" are those that are set periodically, based on the current price of the marginal fuel and the current IER for each utility. "Fixed energy payments" are those for which at least the IER is established by contract for some period longer than the update cycle used for recalculating the bases for variable energy payments.

14. "QFs-out" (when used in relation to variable energy payments) represents the computer-modelled dispatch of a utility system with all variably-priced QFs removed. In the same context, "QFs-in" represents system dispatch including all variably-priced

QFs anticipated to be on-line during the forecast period. "QFs-in/QFs-out" refers to the average of the IERs calculated by performing both computer runs for a given utility system.

15. Edison's zero-intercept method for calculating the QFs-in IER has the advantage of being relatively insensitive (compared to the instantaneous marginal rate) to minor variations in assumptions.

16. Under certain circumstances, QFs-in/QFs-out does not realistically reflect what a utility would have done to replace short-run QF power. However, these circumstances are likely to exist only when short-run QFs constitute a relatively larger part of a utlity's resource mix than they presently do for PG&E, SDG&E, or Edison. Also, refinements to QFs-in/QFs-out proposed by DRA, SFG/U/F, and IEP could mitigate the problem.

17. QFs-in undervalues short-run QFs so long as the purchasing utility can recover its full cost of replacing QF deliveries, should these fall short of the quantity estimated for purposes of calculating the QFs-in IER. Thus, QFs-in strengthens the utility monopsony because only the QFs have to compete at the QFs-in price, while the utility in case of need can dispatch less efficient resources and still recover its excess costs through ECAC.

18. QFs-in/QFs-out is the appropriate energy pricing method for final Standard Offer 4 QFs in Period 1, regardless of the pricing method for other QFs receiving variable energy payments.

19. The primary purpose of state and federal policies regarding QF development is to create a pricing structure that captures to the extent possible the efficiency and other benefits of perfect competition in electricity generation. Neither QFs-in nor QFs-in/QFs-out will fully capture these benefits under existing conditions.

20. A primary function of the standard offers is to reduce the transaction costs of creating power purchase agreements between utilities and QFs.

21. The existence of standard offers also helps in the creation of nonstandard power purchase agreements because the parties to such agreements may be able to use most of the standard provisions and thus to concentrate their efforts on project-specific provisions (e.g., additional performance features) that would benefit both seller and utility.

22. It is appropriate to defer to the biennial update proceeding following ER-7 the contract issue of when and for how long the capacity factor assumed for the avoidable resource should be fixed.

23. The general terms of the curtailment provision proposed in the Joint Testimony are consistent with the Commission's goal of integrating QFs in utility system operation through flexible operating and pricing terms.

24. Under the final Standard Offer 4 methodology, the value of a QF's capacity is measured in terms of the capacity that the utility defers or avoids as a result of the QF's commitment.

25. PG&E has not shown, either that the firm capacity demonstration test proposed in the Joint Testimony is technically inadequate, or that conditions on the PG&E system require a more stringent test.

26. Sales of electricity by final Standard Offer 4 QFs to neighboring retail loads are very unlikely to contribute to uneconomic bypass.

27. The relevant provision in the Joint Testimony reasonably specifies the QF's duties in a system emergency.

28. The relatively high dependence of PG&E's system on hydro resources has an impact on the desirable frequency of IER updating; however, such updating is largely irrelevant to energy pricing for final Standard Offer 4 QFs.

29. It is reasonable to establish a mechanism in the respective utilities' tariff rules for allocating available transmission capacity to final Standard Offer 4 QFs. These tariff rules could also appropriately include the respective utilities' technical specifications for QF-utility system interconnections.

30. The implementation of ramped payment streams as proposed in the utilities' compliance filings is consistent with the derivation of the utilities' own revenue requirements and thus preserves ratepayer indifference as between QFs deferring a given resource and the utility acquiring it.

Conclusions of Law

1. The EUE-based ERI method, as implemented by Edison and SDG&E, should be used by these utilities in any proceeding before this Commission when projecting capacity need or valuing capacity already on or to be added to their systems.

2. PG&E's 1987 as-available capacity price ($42 per kilowatt) should be continued through 1988.

3. For long-term capacity planning purposes, the CEC's capacity requirements for PG&E (as projected in the CEC's then-current Electricity Report) should be used.

4. SDG&E should be directed to file a revised capacity price table for reinstated Standard Offer 2 consistent with findings of fact 10 and 11.

5. A utility should show that any given resource proposed for future development in its resource plan is cost-effective, regardless of whether the resource would be deferrable by QFs.

6. The long-term forecasting needed for Standard Offer 2 and final Standard Offer 4 should be done biennially, and these offers should be updated in coordination with the CEC's Electricity Report process.

7. Variable capacity payments to QFs should be updated annually in ECAC proceedings.

8. The QFs-in/QFs-out method for calculating short-run energy prices is consistent with the PURPA avoided costs standard.

9. To the extent that changes in ECAC and possibly other developments create a more competitive environment and move the electric industry closer to a true spot market, it is consistent with PURPA to reconsider marginal energy cost pricing for short-run QFs.

10. The final Standard Offer 4 contract provisions set forth in Exhibit 446, as supplemented by the agreements set forth in Exhibit 447, should be approved in their entirety. Proposals by IEP and PG&E to modify those provisions should be rejected.

11. The curtailment terms set forth in Appendix A of Exhibit 447 should be approved and the parties should be directed to continue workshops to draft conforming contract language.

12. PG&E and Edison should be authorized to file advice letter revisions to their respective tariff rules regarding technical specifications for QF-utility interconnections, as described in Section IV.H.2 of this decision. PG&E, SDG&E, and Edison should also file advice letter revisions to include in Tariff Rule 21 of each utility a mechanism for allocating available transmission capacity to final Standard Offer 4 QFs.

13. The capacity factor updating issue should be deferred to the biennial resource plan update proceeding following ER-7. Save for this issue, PG&E, SDG&E, and Edison should file a complete final Standard Offer 4 in compliance with this decision, such filing to be due no later than 90 days after today.

14. This opinion and order should be made effective today in order to expedite completion of the work in implementing final Standard Offer 4 and reinstating Standard Offer 2.

15. PG&E's petition for modification of D.86-07-004 should be granted with respect to the proposed treatment of improvements to hydroelectric projects in the context of relicensing proceedings.

THIRD INTERIM ORDER - COMPLIANCE PHASE

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (Edison) shall use the capacity valuation method described in finding of fact 1 and conclusion of law 1 for purposes of the biennial resource plan update proceeding and in any other proceeding before this Commission when projecting capacity need or valuing capacity already on or to be added to their systems.

2. The 1988 capacity price for as-available Qualifying Facilities (QFs) on the system of Pacific Gas and Electric Company (PG&E) shall be $42 per kilowatt. A schedule for comment on the method for future adjustments to PG&E's variable capacity payments, including the proposal described in Section II.E of today's decision, shall be set by ruling of the assigned Commissioner or Administrative Law Judge.

3. For long-term capacity planning purposes in proceedings before this Commission, the capacity requirements for PG&E as shown in the then-current Electricity Report of the California Energy Commission (CEC) shall be used.

4. SDG&E shall file within 30 days of the date of issuance of this decision a revised capacity price table for reinstated Standard Offer 2 consistent with findings of fact 10 and 11.

5. Division of Ratepayer Advocates shall study the reliability models used by the parties in this proceeding and shall include its observations in future reports prepared pursuant to Public Utilities Code Sections 1821-1824. This study shall include a description and comparison of the various models and how they are calibrated, and shall recommend any appropriate modeling conventions to be used in future proceedings before this Commission.

6. Division of Ratepayer Advocates, in coordination with CEC Staff, shall hold a public workshop to discuss potential improvements in analyzing electric system reliability and capacity valuation, including the value-of-service approach.

7. Variable capacity payments to QFs shall be updated annually in Energy Cost Adjustment Clause (ECAC) proceedings.

8. The final Standard Offer 4 contract provisions set forth in Exhibit 446, as supplemented by the agreements set forth in Exhibit 447, are approved in their entirety.

9. The curtailment terms set forth in Appendix A of Exhibit 447 are approved in principle. The parties shall file their recommendations on final Standard Offer 4 contract language conforming to these terms within 30 days of the date of issuance of this decision. The parties are strongly encouraged to develop a joint recommendation for the Commission's consideration.

10. PG&E and Edison shall file advice letter revisions to their respective tariff rules regarding technical specifications for QF-utility interconnections (Tariff Rule 21) in order to incorporate certain material, as described in Section IV.H.2 of this decision. PG&E, SDG&E, and Edison shall also file advice letter revisions to the same rule to include a mechanism for allocating available transmission capacity to final Standard Offer 4 QFs. These advice letter revisions shall be filed within 30 days of the date of issuance of this decision.

11. The capacity factor updating issue shall be deferred to the biennial resource plan update proceeding following the CEC's Seventh Electricity Report.

12. PG&E, SDG&E, and Edison shall file a complete final Standard Offer 4 in compliance with this decision within 90 days of the date of issuance of this decision.

13. Unlike other generation resources, improvements to hydroelectric projects proposed in the context of relicensing proceedings at the Federal Energy Regulatory Commission shall be

15. PG&E's petition for modification of D.86-07-004 should be granted with respect to the proposed treatment of improvements to hydroelectric projects in the context of relicensing proceedings.

THIRD INTERIM ORDER - COMPLIANCE PHASE

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (Edison) shall use the capacity valuation method described in finding of fact 1 and conclusion of law 1 for purposes of the biennial resource plan update proceeding and in any other proceeding before this Commission when projecting capacity need or valuing capacity already on or to be added to their systems.

2. The capacity price for as-available Qualifying Facilities (QFs) on the system of Pacific Gas and Electric Company (PG&E) shall continue to be $42 per kilowatt. A schedule for comment on the method for future adjustments to PG&E's variable capacity payments, including the proposal described in Section II.E of today's decision, shall be set by ruling of the assigned Commissioner or Administrative Law Judge.

3. For long-term capacity planning purposes in proceedings before this Commission, the target reserve margins for PG&E as shown in the then-current Electricity Report of the California Energy Commission (CEC) shall be used.

4. SDG&E shall file within 30 days of the date of issuance of this decision a revised capacity price table for reinstated Standard Offer 2 consistent with findings of fact 10 and 11.

5. Division of Ratepayer Advocates shall study the reliability models used by the parties in this proceeding and shall include its observations in future reports prepared pursuant to Public Utilities Code Sections 1821-1824. This study shall include a description and comparison of the various models and how they are

treated as generically unavoidable by QFs. In a biennial resource plan update proceeding, the resource plan of a utility applicant shall reflect such anticipated improvements by identifying the projected capacity, output, and operational date of each such improvement, but need not otherwise describe the improvement or justify its cost-effectiveness.

14. Except to the extent granted in Ordering Paragraph 13, PG&E's petition for modification of Decision 86-07-004 is denied.

This order is effective today.

Dated ____________________, at San Francisco, California.

calibrated, and shall recommend any appropriate modeling conventions to be used in future proceedings before this Commission.

6. Division of Ratepayer Advocates, in coordination with CEC Staff, shall hold a public workshop to discuss potential improvements in analyzing electric system reliability and capacity valuation, including the value-of-service approach.

7. Variable capacity payments to QFs shall be updated annually in Energy Cost Adjustment Clause (ECAC) proceedings.

8. The final Standard Offer 4 contract provisions set forth in Exhibit 446, as supplemented by the agreements set forth in Exhibit 447, are approved in their entirety.

9. The curtailment terms set forth in Appendix A of Exhibit 447 are approved in principle. The parties shall file their recommendations on final Standard Offer 4 contract language conforming to these terms within 90 days of the date of issuance of this decision. The parties are strongly encouraged to develop a joint recommendation for the Commission's consideration.

10. PG&E and Edison shall file advice letter revisions to their respective tariff rules regarding technical specifications for QF-utility interconnections (Tariff Rule 21) in order to incorporate certain material, as described in Section IV.H.2 of this decision. PG&E, SDG&E, and Edison shall also file advice letter revisions to the same rule to include a mechanism for allocating available transmission capacity to final Standard Offer 4 QFs. These advice letter revisions shall be filed within 90 days of the date of issuance of this decision.

11. The capacity factor updating issue shall be deferred to the biennial resource plan update proceeding following the CEC's Seventh Electricity Report.

12. PG&E, SDG&E, and Edison shall file a complete final Standard Offer 4 in compliance with this decision within 90 days of the date of issuance of this decision.

APPENDIX A
Page 2

MAREL	Multi-Area Generation System Reliability Model (II.F)
PG&E	Pacific Gas and Electric Company (I)
PURPA	Public Utility Regulatory Policies Act of 1978, as amended (III.E.3)
QF	Qualifying Facility (I)
R.	Order Instituting Rulemaking (III.E.4)
SDG&E	San Diego Gas & Electric Company (I)
SFG/U/F	Santa Fe Geothermal, Inc., Union Oil Company of California, and Freeport-McMoRan Resource Partners (II.D)
Tr.	Reporter's Transcript (IV.G.3)

APPENDIX A
Page 1

Table of Acronyms and Abbreviations

This table contains an expansion of each acronym and abbreviation used in today's decision. Following the expansion is a reference to the section in the body of the decision where the acronym or abbreviation first appears.

ALJ	Administrative Law Judge (II.E)
BTU	British thermal unit (III.A)
CEC	California Energy Commission (II)
CFR	Code of Federal Regulations (III.E.4)
CPUC or Commission	California Public Utilities Commission (II.A)
D.	Decision (I)
DRA	Division of Ratepayer Advocates of CPUC (formerly Public Staff Division (I)
ECAC	Energy Cost Adjustment Clause (I)
ECG	Energy Consulting Group (II.G)
Edison	Southern California Edison Company (I)
ER-6	The CEC's Sixth Electricity Report (II)
ERI	Energy Reliability Index (I)
EUE	Expected Unserved Energy (I)
FERC	Federal Energy Regulatory Commission (II.A)
IEP	Independent Energy Producers Association (I)
IER	Incremental Energy Rate (III)
LOLE	Loss of Load Expectation (II)
LOLP	Loss of Load Probability (II.E)

13. Unlike other generation resources, improvements to hydroelectric projects proposed in the context of relicensing proceedings at the Federal Energy Regulatory Commission shall be treated as generically unavoidable by QFs. In a biennial resource plan update proceeding, the resource plan of a utility applicant shall reflect such anticipated improvements by identifying the projected capacity, output, and operational date of each such improvement, but need not otherwise describe the improvement or justify its cost-effectiveness.

14. Except to the extent granted in Ordering Paragraph 13, PG&E's petition for modification of Decision 86-07-004 is denied.

This order is effective today.

Dated ______________________, at San Francisco, California.