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Decision 90 03 060 MAR 28 1990

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's own motion to implement the Biennial Resource Plan Update following the California Energy Commission's Seventh Electricity Report.	I.89-07-004 (Filed July 6, 1989)

(See Attachment 5 for appearances.)

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PHASE 1A INTERIM OPINION:
ADOPTED BASE CASE RESOURCE PLANS

I. Summary of Decision

In today's decision, we adopt base case resource planning assumptions for the Biennial Resource Plan Update (BRPU). These assumptions are used to determine whether California's investor-owned utilities (IOUs) need additional resources over the next 12 years and, if so, to identify those that are potentially deferrable by qualifying facilities.

We reaffirm our prior determinations in Application (A.) 82-04-44 et al. that only existing and committed resources are included in the utility's resource plan, in considering the cost-effectiveness of potential resource additions. We also establish specific guidelines for what constitutes a "committed" resource, for this and future BRPU proceedings. In addition, we address specific implementation issues regarding our adopted methodology for testing resource cost-effectiveness. We direct respondents to submit revised analyses of their resource needs, using the assumptions and methods adopted in today's order.[1]

II. Background

A. Scope and Purpose of the BRPU

We opened this investigation to officially recognize the start of our current BRPU cycle. In the BRPU, we update long-term

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1 Attachment 6 explains each technical acronym or other abbreviation that appears in this decision, and also refers the reader to the section of the opinion where the abbreviation first appears.

forecasts and address generic issues related to utility purchases of electricity from nonutility energy producers, termed "qualifying facilities" or "QFs". Our regulation of these purchases relies on two concepts: avoided costs (as to the purchase price) and the standard offer (as to the contractual relationship).

Avoided costs represent the costs a utility would incur, if not for the presence of QFs, to generate power itself or purchase it elsewhere. The standard offer is a utility offer to purchase electricity from a QF, at the QF's sole option. The contract terms of that offer are formed within guidelines adopted by this Commission. Over the past ten years, we have refined and implemented these concepts in a series of decisions. (See Attachment 1.)[2]

The BRPU provides us with an industry-wide forum for continuing our regulatory oversight of utility/QF matters. Its scope is described in the Administrative Law Judge's (ALJ) April 19, 1989 Ruling in A.82-04-44 et al., attached to this order. (See Attachment 4.) As described in that ruling, a major purpose of the BRPU is to update the prices for final Standard Offer 4 (FSO4), our resource plan-based standard offer. This involves quantifying the megawatts (MWs) that QFs can fill on the basis of each utility's need for new capacity. Each two-year update cycle commences upon issuance of the California Energy Commission's (CEC) Electricity Report.

The BRPU is also the forum for updating certain components of QF payments that affect our short-run offers,

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2 The federal Public Utility Regulatory Policies Act (PURPA) of 1978 and the California Private Energy Producers Act (See Public Utilities Code §§ 2801-2824) supply the statutory context for the development of these concepts. The decisions listed in Attachment 1 all elucidate this legislation and these concepts.

Standard Offers 1, 2, and 3 (SO1, SO2, and SO3, respectively).[3] In Decision (D.) 88-09-026 and D.89-02-017, we also directed parties to address issues relating to SO2 availability in this update. By ruling dated July 17, 1989, the Assigned Commissioner added nondiscriminatory transmission access for QFs to the list of issues. In addition, as outlined in the April 19, 1989 ALJ Ruling, several implementation and contract issues for interim and FSO4 were deferred to this update. Finally, each BRPU provides a forum for considering changes in methodology or contract terms for all of our standard offers.

B. How Final Standard Offer 4 Works

Before discussing the issues resolved in today's decision, we summarize briefly the structure created for FSO4 in D.86-07-004. Unlike our short-run standard offers, FSO4 derives from a utility's long-run marginal costs (also referred to as long-run avoided costs or LRACs.)[4] LRACs are determined from the respective utility's resource plan, which includes all cost-effective potential resource additions (e.g., new plant construction, refurbishments, power purchases, etc.).[5] FSO4

3 These three offers are referred to as "short-run" because the energy price is computed on the basis of the purchasing utility's existing generation resources. In contrast to our FSO4 "long-run" pricing approach, prices for these standard offers are calculated without consideration of possible resource additions. Attachment 2 summarizes the pricing provisions of our various standard offers.

4 Long-run marginal costs and LRACs are used interchangeably in this decision as representing the long-run incremental costs of a utility system, assuming that the utility adds only cost-effective resources to its resource plan.

5 QFs do not avoid or defer any resource that, as analyzed in the resource planning process, would not be cost-effective. The reason is that a prudent utility would not commit to such a resource in the first place. (See D.86-07-004, mimeo. p. 7.)

prices are based on those additions that serve as baseload or intermediate-load resources.

Pricing under FSO4 varies according to when the QF comes on-line. During Period 2, the QF avoids a specific utility resource addition, and the QF receives payments based on the fixed and variable costs of the avoided resource. If the QF comes on-line in Period 1, i.e., before the date when the avoided resource would have begun delivery of electricity, the QF meets near-term demand growth, and therefore the QF receives short-run marginal cost-based payments until the start of Period 2.

The Commission considers alternative scenarios for each utility in determining a MW limit at each update proceeding. Whenever the capacity of QFs seeking FSO4 contracts from a given utility exceeds that utility's MW limit, the available contracts are allocated through bidding. The utilities are also authorized to pay QFs additional sums for providing performance features (e.g., downward dispatchability at the utility's direction) not otherwise required under the standard offers. Attachment 3 presents a more detailed chronological overview of the FSO4 updating process.

C. <u>Phasing of the Issues</u>

In order to manage effectively the myriad complex issues in this BRPU, we divided the proceeding into three major phases. The current Phase, Phase 1, encompasses all the steps for developing LRACs and a resource plan-based FSO4, using our adopted methodology. As described in Attachment 4, Phase 1 was further subdivided into Phases 1A, 1B, and 1C. Phase 1A, which is the subject of today's order, involves developing a base case set of demand, supply and resource cost assumptions for each utility. This set of assumptions is used to implement our Iterative Cost Effectiveness Method (ICEM) for identifying resources that are deferrable by QFs. (See Section E. below.) In conducting the ICEM analysis for Phase 1A, respondents were directed to develop the base case using the CEC's adopted Seventh Electricity Report (ER7) supply and demand assumptions.[6]

In Phase 1B, we will address the impacts of uncertainty and relevant strategic elements in developing an FSO4 solicitation. As described in Section III.D.2.c. below, during Phase 1B we will also examine how we may enable QFs to compete with power purchase opportunities that materialize between updates. In addition, Phase 1B is the forum for addressing SO2 reinstatement issues, and for incorporating environmental considerations into an SO2 solicitation, should one be issued during this update cycle. (See Section VIII.D.)

Assuming that QF deferrable resources are identified in Phase 1B, we will proceed in Phase 1C to quantify a selected number of adders prior to soliciting bids. In Phase 2, we will update cost components that affect other standard offers. Proposals to modify any of our standard offers, to improve overall integration of our resource planning proceedings, as well as the issue of transmission access, will be considered in Phase 3.

D. Procedural History

1. A.82-04-44 et al.

This BRPU proceeding represents the first update cycle since our adoption of a costing methodology, contract terms, and bidding protocol for FSO4, and completion of compliance hearings on the utility resource plan filings in A.82-04-44 et al. As such, the procedural history of this investigation is inextricably linked to that of its predecessor. We present below a brief overview of the steps we took in A.82-04-44 et al., the consolidated standard offer proceeding, to develop our resource-plan based offer.

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6 1988 Electricity Report, California Energy Commission, June 1989.

During Phase I of the LRAC hearings in A.82-04-44 et al., we considered a variety of costing methodologies to serve as the basis for calculating FSO4 prices.[7] In D.85-07-022, we found that the Public Staff's (subsequently renamed Division of Ratepayer Advocates and referred to in this decision by that name) "simplified" generation resource plan (GRP) approach would best achieve the goals for this methodology, namely, accuracy, verifiability, and practicality in implementation.

During Phase II, we considered various proposals for translating the LRAC methodology adopted in D.85-07-022 into a structure for FSO4. In D.86-07-004, dated July 2, 1986, we adopted the structure described in Section B. above. The CEC adopted its then current Electricity Report (ER6) in December, 1986.[8] The utility compliance filings followed in March 1987. Pursuant to our directives in D.86-05-024 and D.86-07-004, these filings included the utility's resource plan under a CEC-based scenario.

In D.87-05-060, dated May 29, 1987, we approved a detailed bidding protocol for FSO4, resolved a variety of pricing issues, and discussed the treatment of uncertainty and negotiated contracts in resource planning.

In the compliance decisions that followed (D.87-11-024, D.88-03-026, D.88-03-079, and D.88-09-026), we reviewed the utility resource plans and addressed resource plan-related issues. In D.87-11-024, we found that none of the utilities had an avoidable resource within the eight-year "window" that we established for purposes of FSO4. We also discussed the concept of "disaggregated resource need" and how it relates to avoidable resources.

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7 In D.85-07-022 (mimeo. pp. 3-8), we present a detailed account of the procedural history leading up to Phase I.

8 <u>1986 Electricity Report</u>, California Energy Commission, December 1986.

In D.88-03-026, we established how and where we would update the provisions of the various standard offers, including FSO4. In D.88-03-079, we developed reliability targets for resource planning and capacity valuation purposes, and addressed certain contract drafting problems in FSO4. In D.88-09-026, our final compliance phase decision, we addressed various resource planning issues that would affect future filings, evaluated the utilities' assessment of performance adders, and discussed the future availability of SO2.

2. <u>The ER7 Update Cycle</u>

On February 27, 1989, the Assigned Commissioner issued a ruling outlining a proposed schedule, scope and phasing of the issues for the current BRPU cycle. The Assigned Commissioner solicited written comments on these procedural matters, and a prehearing conference (PHC) was held on April 7, 1989 to discuss then further.

On April 19, 1989, ALJ Gottstein issued a final ruling in A.82-04-44 et al. outlining the scope of issues to be addressed in each phase of the BRPU, Phase 1A filing requirements, and the Phase 1A schedule for workshops and evidentiary hearings (April 19 ALJ Ruling).

Workshops on contract-related issues were held during the spring and summer of 1989. Workshop reports were filed on May 31, 1989, June 21, 1989, and August 3, 1989.[9]

On June 8, 1989 the CEC issued its ER7 final report, which officially initiated this BRPU cycle. On June 15, 1989, the

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9 Two contract-related issues were deferred to this update, and addressed during Phase 1A hearings: (1) whether or not the capacity factor assumed for the FSO4 deferrable resource should be updated and, if so, how; and (2) the appropriate treatment of curtailment adders under Pacific Gas and Electric Company's interim Standard Offer 4. These two issues were briefed separately, and will be addressed in a subsequent interim opinion.

CEC held workshops on its draft ER7 data set for the ELFIN production cost model. The final ER7 data set was distributed to interested parties on June 28, 1989.

On July 6, 1989, we closed A.82-04-44 et al. and issued this Order Instituting Investigation (OII). The OII incorporated the April 19 ALJ Ruling, and all issues carried over to this BRPU cycle. On August 17, 1989, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E, collectively respondents), filed their Phase 1A compliance reports and testimony.

Phase 1A workshops on the resource plan and modelling issues were held on August 31 and September 12, 1989.[10] A workshop report on these issues was filed on September 21, 1989 (Exhibit (Exh.) 9). A second PHC on Phase 1A procedural and scheduling matters was held on September 29, 1989.

Intervenor testimony was filed on October 19, 1989 by the Division of Ratepayer Advocates (DRA), Independent Energy Producers/Independent Power Corporation (IEP/IPC), CEC, and Santa Fe Geothermal, Unocal Corporation and Freeport-McMoRan Resource Partners (SF/U/F).[11] Respondents filed rebuttal testimony on November 7, 1989. Phase 1A evidentiary hearings were held November 13-17, 28-30, December 1 and 4. Concurrent briefs on Resource Plan and ICEM issues were filed on December 22 and (for

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10 All parties who conducted the ICEM analysis as part of their Phase 1A testimony used the ELFIN production cost model to do so. Therefore, modelling issues regarding differences among models were not raised during this phase of the proceeding.

11 The Cogenerators of Southern California (CSC) originally filed testimony on the specific issue of gas prices. However, upon a favorable ruling on their motion to strike portions of SCE's testimony, CSC withdrew its testimony, and did not not participate further in Phase 1A.

DRA only) December 29, 1989. Concurrent briefs on contract-related issues were filed on January 5, 1990.

On January 2, 1990, ALJ Gottstein issued a ruling directing respondents to submit additional ICEM analyses, using the specific assumptions, modelling conventions, and cost-effectiveness testing methods outlined in the ruling (January 2 ALJ Ruling). A workshop to discuss and clarify the specifics of this ruling was held on January 11, 1990. On January 16, 1990 ALJ Gottstein issued a subsequent ruling summarizing the issues discussed at the workshop and identifying certain modifications to the January 2 ALJ Ruling.

Each respondent filed one additional ICEM analysis on January 19, 1990. SDG&E filed a second analysis, as directed by the January 2 ALJ Ruling, on February 2, 1990. Comments on these filings were submitted on February 5 and 20, 1990, respectively.

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 Gottstein was filed before today's decision, on February 16, 1990. Respondents, DRA, IEP/IPC, CEC, Bonneville Power Administration (BPA), and SF/U/F filed comments on the proposed decision. No reply comments were filed.

We have carefully reviewed the comments, but have not summarized them in this order. To the extent that they required discussion, or changes to the proposed decision, the discussion and changes have been incorporated into the body of this order.

E. The ICEM Approach: An Overview

As described above, the primary focus of Phase 1A is to implement our adopted LRAC methodology for identifying resources that are deferrable by QFs. In D.86-07-004, we adopted, with one modification, the DRA's ICEM methodology for determining the type and timing of potentially deferrable resources.[12] Since all the issues addressed in today's order involve implementation aspects of the ICEM, a brief overview should prove useful to the unfamiliar reader. In brief, the ICEM consists of the following three steps:

Step 1: Each utility submits projections of its current resource plan, assuming no new resource additions, along with a computer model simulation of how the system would be dispatched to meet electric loads (the "barebones" resource plan). This simulation produces year-by-year projections of total production costs, i.e., the fuel/power purchase and other variable operating costs a utility would incur to meet loads.[13]

Using the barebones resource plan assumptions, the utility also calculates year-by-year "shortage costs" for its system. Shortage costs are a measure of a utility's need for new capacity, and the capacity cost a utility avoids by purchasing

12 In D.86-07-004, we eliminated the "inframarginality test" proposed by DRA and other parties in A.82-04-44 et al. This test was designed to identify those resources which are so cheap that their addition to the utility system would occur, whether or not QF power is present. More specifically, the inframarginality test identifies resources that are cheaper than projected system costs, based on a resource plan that includes all expected QF supply and cost-effective, non-QF resource additions. (See reference Exh. A, p. 50, pp. C-4 to C-5.) We determined that it was not appropriate to shield any particular price range of resource additions from displacement by QF and non-QF sellers. (D.86-07-004, mimeo. p. 83 and Finding of Fact (FOF) 39.)

13 The barebones resource plan does assume the addition of shortage resources (with combustion turbines as a proxy) to meet reserve margin requirements.

power from QFs for a specified period. They are estimated by the cost of a combustion turbine (CT), adjusted by an energy reliability index (ERI).[14] The sum of these two values, production and shortage costs, can be thought of as total system costs for the barebones resource plan.

Step 2: Each utility develops cost estimates and operating characteristics for various candidate resource additions. A new computer run is made with one of these resources included in the resource plan. This produces a new set of production cost estimates. Similarly, new shortage values are calculated. The sum of these values represents total system costs with the new resource added.

Using these results, and comparing them with the barebones simulation, the candidate resource is tested for first-year and life-cycle cost-effectiveness. The resource is considered cost-effective, and added to the utility's resource plan, if it passes both these tests.

Candidate resources are evaluated one at a time. If a cost-effective resource is identified, it is added to the resource plan in the appropriate year, based on the first-year test. This adjusted resource plan becomes the new reference for evaluating the next candidate resource (i.e., the next production cost run and shortage value calculation). This process is repeated in an iterative fashion until all cost-effective resources are added.

Step 3: After conducting the ICEM for all candidate resource additions, each utility produces its final "least-cost"

14 More specifically, shortage costs on the utility system at any given time are defined as the expected cost of an outage at that time. (See D.82-12-120, mimeo. p. 77.) The ERI is a way of expressing whether the value of additional capacity on an electric utility system in a given year is the same as, greater or less than the utility's marginal capacity investment, assumed to be a CT.

resource plan. This plan indicates the type and timing of all cost-effective resource additions during the 12-year planning horizon. The utility's long-run marginal costs are also derived from this plan. QF prices under FSO4 are based on the costs of any baseload or intermediate load resources added during the first eight years, unless otherwise determined to be "nondeferrable" by the Commission.

F. Phase 1A Issues on Resource Plans/ICEM

For Phase 1A, parties were directed to conduct their ICEM analyses using the CEC's ER7 supply and demand assumptions. (See Attachment 4.) Debate over resource assumptions during this phase was limited to the following three specific areas:

(1) Any inconsistencies in the CEC's definition of "barebones" (existing and committed resources), relative to this Commission's definition;

(2) Any assumptions that were not addressed and resolved in ER7; and

(3) The types and associated costs of potential resource additions.

In addition, the following ICEM implementation issues were deferred to this BRPU cycle:

(4) What method(s) to adopt for connecting short-run and long-run demand forecasts; and

(5) How to apply the new gas rate design in testing the cost-effectiveness of potential new resources.

During the course of Phase 1A hearings, it became apparent that we would also need to address the detailed methodological steps and various modelling conventions for implementing the ICEM.

These Phase 1A issues are discussed in Sections III-VII. below.

III. The Base Case Resource Plan

By far the most controversial debate during this phase of the proceeding was over the appropriate starting point, or base case, for the Phase 1A ICEM analysis. CEC accurately describes the genesis of this controversy in its brief:[15]

> "In the ALJ ruling of April 19, 1989, Judge Gottstein directed the utilities and parties to prepare 'barebones' resource plans based on ER7 resource assumptions as the starting point for implementing the ICEM analysis. In that same ruling, Judge Gottstein asked the CEC Staff to provide, and directed the parties to use, ELFIN data sets based on ER7. Since this ruling appeared prior to the release in May 1989 and adoption on June 1, 1989 of the final Electricity Report, the ruling could not have anticipated the conflict inherent in its two directions.
>
> "The conflict arose when ER7 ultimately adopted resource planning assumptions that went significantly beyond what CPUC decisions anticipated from this Electricity Report. ER7 contained two categories of resources--nondeferrable and pending--that the CPUC did not expect to see in a CEC 'barebones' resource case. Aware that this conflict existed, but also cognizant of the need to provide the CPUC with a complete view of electricity resource development in the state, the CEC prepared data sets that are entirely consistent with ER7 (as the ALJ's ruling requested), but which also include these additional resource categories not anticipated by the ALJ's ruling. Much of the Phase 1A debate over resource planning

15 California Energy Commission Brief on Phase 1A (CEC Brief), December 21, 1989, page 2.

assumptions arose from this inherent conflict."[16]

The significance of this debate stems from the fact that (1) by definition, a QF cannot bid against the MWs associated with a nondeferrable resource through an FS04 and (2) when more resources are included in the base case plan, less resources will pass the iterative cost-effectiveness tests.[17] Hence, the decision to include or exclude certain resources from the base case can have a major impact on the type and timing of deferrable resources and, in turn, on FS04 prices.

Tables 2A-2C outline the specific areas of disagreement over which resources (and resource categories) should be included in the base case resource plan. In addition, some parties disagreed with CEC's designation of certain resources in one category or another. The positions of parties with regard to each of the three major resource categories (i.e., existing and committed, pending and nondeferrable) are described below.

16 We note that most of the types of resources included in the ER7 pending and nondeferrable categories were not considered by the CEC in their system analysis of resource needs for ER6. See ER6, pp. 4-7 to 4-12; Reporter's Transcript (TR) at 655-659, 668-673.

17 This is because shortage costs, one component of total costs always goes down as you add resources to the resource plan. (Production costs may also go down if the resource is priced in such a way that it displaces higher cost energy.) In this way, the cost-effectiveness tests are more stringent for subsequent additions, and it becomes harder to identify deferrable resources over the planning horizon.

A. <u>Existing and Committed Resources</u>.

The ER7 data set includes price and availability assumptions for resources under ER7's "existing and committed" category. Under this category, CEC includes:[18]

- o Resources which are currently operational;
- o Signed contracts for power purchases or exchanges;
- o Savings from implemented conservation and load management programs; and
- o Resources which are going to come on-line without future action by a state regulatory authority.

All parties agree that existing and committed resources should be included in the base case resource plan at the outset of the ICEM analysis. Moreover, parties generally agree with CEC's designation of resources under this category, with the major exceptions discussed below.[19]

1. <u>New QFs/Self-Generation</u>

Under existing and committed resources, the CEC includes two forecasts of QF development. The first is a "short-run" forecast of QF development for projects with signed contracts. It is based on a project-by-project assessment of the likelihood that projects under existing standard offer contracts will come on-line. The CEC's short-run forecast for QFs with signed contracts extends through 1991, the last year projects with interim SO4 contracts are

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13 ER7, p. 4-15.

19 See also Section D.2.h. below, where we summarized the uncontested proposals for modifying the ER7 base case.

assumed to be operational. Similarly, the CEC developed a short-run forecast of self-generation.[20]

The second is a "long-run" forecast of currently nonexisting QFs and associated self-generation, based on projections of economic potential. For all three respondents combined, these new QFs/self-generation represent approximately 800 MW of dependable capacity over the planning horizon. CEC assumes that new QF capacity over and above self-generation requirements will be sold to the respondents under our as-available SO1 and SO3. (See TR at 672.)

All parties agree that the base case resource plan should include the ER7 short-run forecast of QF/self-generation development. CEC, PG&E, SCE, and SDG&E also recommend that the long-run forecast be included in the barebones plan. DRA would include the CEC's forecast of self-generation additions, but exclude new SO1 and SO3 QFs.[21] SF/U/F and IEP/IPC, on the other hand, argue that none of these new resources can properly be considered existing or committed, and should therefore be omitted from the Phase 1A base case.

More specifically, SF/U/F and IEP/IPC point out that there are no contracts in force for the development of these resources. Furthermore, IEP/IPC argues, no specific sites are identified, and no project development milestones were considered. SF/U/F also notes that, with limited exceptions, specific parties

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20 For ER7, self-generation is treated as a load to be served and a resource available to meet load.

21 This position was developed during the course of evidentiary hearings, and argued in DRA's Concurrent Brief. In Exh. 24, DRA makes no specific recommendation regarding this resource category. See <u>Brief of the Division of Ratepayer Advocates for Phase 1A</u> (DRA Brief), December 29, 1989, pp. 3-6; TR at 594, 608.

who could build these resources have not been identified. Finally, IEP/IPC argues that inclusion of these resources in the barebones plan contradicts the Commission's determinations in D.85-07-022. To the extent that future development of QF/self-generation represents an uncertainty that should be considered, IEP/IPC and SF/U/F argue that Phase 1B is the appropriate forum for this consideration.

In rebuttal, SDG&E and SCE assert that the Commission considered SF/U/F's and IEP/IPC's position once before and, in D.86-07-004, declined to adopt it. SDG&E also argues that, similar to demand, self-generation is beyond a utility's control. For this reason, the Commission has deferred to the CEC for these forecasts, SDG&E claims. Moreover, SDG&E argues that removing these resources would intentionally overstate need. Similarly, PG&E urges the Commission to adopt ER7 conclusions that the likelihood of these resources being developed is strong enough to label them "committed". CEC also points to language in the <u>Joint CEC/CPUC Proposed Resource Accounting Terminology</u> (Exh. 10) as supportive of including future self-generation under the committed category.

DRA distinguishes between two components of the new additions (i.e., self-generation only, and forecasted SO1/SO3 QFs). DRA's recommendation to remove the latter component is based on the expectation that FSO4 contracts could displace the SO1 contracts that are being forecasted. In DRA's view, it is preferable to have the FSO4 contracts. DRA does not believe that removing the self-generation forecast will have similar ratepayer benefits and, hence, does not recommend excluding those resource additions from the barebones resource plan.

2. <u>New Standard Offer 2 QFs</u>

In D.89-02-017, dated February 8, 1989, the Commission identified four successful QF bids for SDG&E's SO2 solicitation. These QF projects, totalling 182.2 MW, were included as pending resources in the ER7 data set. (See Table 1.) Three of these projects would require CEC certification.

SDG&E argues that these resources should be redesignated as committed resources because (1) SDG&E expects that these projects will successfully develop, and (2) pursuant to D.89-02-019, SDG&E is obligated to enter into these contracts. For similar reasons, DRA and CEC agree that these types of resources should generally be included in the base case, but as pending resources. (See Section B.2.d. below.)

In its direct testimony, SF/U/F concurred with SDG&E's treatment of these resources. However, during the course of the proceeding, SF/U/F refined its position. Rather than assuming that all projects would successfully develop, SF/U/F recommends that a more detailed probability assessment or success rate be determined and applied to these QF resources.[22] IEP/IPC, on the other hand, recommends that these resources be excluded, consistent with their recommendations for all other pending resources (TR at 705).

At the request of the assigned ALJ, SDG&E presented a statement of counsel regarding the current status of these pending resources (TR at 781-782). Counsel stated that two of the projects, totalling 52.2 MW of firm capacity, have dropped out (i.e., decided not to sign the SO2 contracts within the Commission specified period). All parties agree that these two projects should be removed from the base case.

B. <u>Pending Resources.</u>

In addition to existing and committed resources, the ER7 data set also included supply assumptions for a category of resources termed "pending" by the CEC. As CEC witness Nix testified, the CEC developed this resource category because "the

22 See <u>Concurrent Brief</u> (SF/U/F Brief), December 22, 1989, p. 5 and TR at 731.

ER7 process identified certain kinds of potential resources that were far too large to ignore in the aggregate, but which did not fit into any of the previously agreed-upon definitions of "existing" and "committed".[23] ER7 defines pending resources as follows:

- o Future resources under development which may materialize in the Electricity Report planning period but await local, state, or federal regulatory approval (including municipal utility resource development);
- o Existing contracts with contingency clauses for additional resources; and
- o Utility and QF projects currently under CEC siting review or anticipated to file for review within the two-year effective period of the Electricity Report.

Table 1 lists the resources included under the pending category for the three utility planning areas. Statewide, pending resources represent nearly 1,700 MW of dependable capacity in 1992, increasing to more than 2,400 MW by 1999.

1. <u>Types of Pending Resources</u>

As indicated in Table 1, the pending category contains a diverse group of resources, which can be grouped as follows:

(1) <u>Investor-Owned Utility Contracts</u>--Executed contracts, including memorandums of understanding (MOUs), that are awaiting regulatory approvals. For ER7, this category includes the PG&E/Seattle, PG&E/Puget, and SCE/Los Angeles Department of Water and Power (LADWP) Exchange Agreements. In addition, ER7 includes an extension beyond 1998 of the peaking capacity option in SDG&E's existing contract with Portland General Electric (PGE).

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23 Exh. 28, pp. 5-6.

(2) QF Contracts--Executed QF contracts currently under CEC review for an Application for Certification (AFC), and anticipated to come under CEC siting review within the year. For ER7, the CEC included four solar projects (Luz SEGS IX-XII) and a cogeneration project (Harbor/Chaplin) in SCE's service territory. In addition, the CEC included SDG&E's four new SO2 contracts under pending, three of which are anticipated to come before the CEC for review. These QFs were not included in the ER7 forecasts of QF/self-generation under existing and committed resources. (See Section III.A.)

(3) Investor-Owned Utility Projects--Projects under review or anticipated to be so at the CEC or CPUC. Projects fitting this description are SCE's Coolwater Coal Gasification Conversion (Coolwater) project, SDG&E's 100 MW South Bay 3 augmentation, and SDG&E's 30 MW retrofit of inlet air coolers. ✓

(4) Municipal (Muni) Resources--Generic generation, transmission and demand-side projects, executed interutility contracts and MOUs.[24] These include: (1) Resale Cities Southwest contract (in SCE's planning area), (2) Burbank and Glendale purchases and exchanges with Portland General Exchange (PGX) (in PG&E's planning area), (3) Northwest purchases over the Muni portion of the California-Oregon Transmission Project (COTP), and Modesto-Santa Clara-Redding's (MSR) access to San Juan #4 (in PG&E's planning area).

(5) Demonstration Projects--The ER7 data set includes one project under this category: the Argus Cogeneration Expansion (ACE) demonstration project in the SCE service area.

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24 Pending Muni resources are included in the ER7 data sets for PG&E and SCE because the CEC planning areas for these two utilities include various Muni loads and resources. ✓

2. <u>Position of the Parties</u>

As summarized in Tables 2A-2C, parties expressed diverse views on which categories of pending resources, if any, should be included in the base case resource plan. SCE and PG&E take the position that all pending resources should be included in the base case for Phase 1A. CEC, SDG&E, and DRA take a more selective approach, and recommend excluding certain categories of pending resources, but not others.[25] SF/U/F and IEP/IPC, on the other hand, argue that none of the pending resources should be included in the Phase 1A analysis.

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

In PG&E's view, keeping pending resources in the base case presents a more balanced resource plan as the starting point for evaluating alternative resources.[26] Moreover, PG&E argues that the directions given in prior Commission decisions intended that great weight be given to the CEC's Electricity Report planning assumptions, which, for ER7, include pending resources. (PG&E Brief, pp. 4-5.) PG&E also understood the April 19 ALJ Ruling to mean that the starting point for establishing the Phase 1A base case is the ER7 data set. Since the CEC only provided a single resource plan to the parties (i.e., the ER7 data set), PG&E contends that this plan is, by default, the CEC scenario that corresponds most closely to the barebones resource plan. (PG&E Brief, pp. 10-11.) For these reasons, PG&E argues that all of the

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25 CEC initially recommended that the Commission use the ER7 data sets, "as is", for the Phase 1A ICEM runs. (See Exh. 28, pp. 11-12.) However, during the course of the proceeding, CEC apparently refined its position to concur with DRA's more selective approach. The discussion below reflects the position presented in CEC's brief.

26 <u>Brief of the Pacific Gas and Electric Company for Phase 1A of the Biennial Resource Plan Update</u> (PG&E Brief), December 22, 1989, p. 7.

CEC resource categories, including pending, should be included in the base case scenario.

With respect to specific pending resources, PG&E argues that its exchange contracts (PG&E/Seattle and PG&E/Puget) should be included based on the CEC's evaluation of their likelihood of going forward. As for Muni resources, PG&E points out that ER7 has balanced Muni loads and resources on the express assumption that PG&E is not responsible for Muni resource planning. Moreover, PG&E considers it a futile exercise to require a utility to do a cost-effective test for a resource over which the utility has no control. (PG&E Brief, p. 13.)

b. SCE

Similar to PG&E, SCE argues that inclusion of all the pending resources is consistent with prior Commission decisions to base FSO4 prices on "a reasonable resource plan which gave the CEC great weight."[27] SCE also interprets the April 19 ALJ Ruling to require use of the ER7 data set, rather than a plan with existing and committed resources only.

SCE contends that including pending resources in the base case gives appropriate recognition of resources that have some likelihood of materializing. In SCE's view, assuming only a strict definition for barebones, e.g., existing and committed, guarantees "perpetuation of the current overcapacity situation." (SCE Brief, p. 11.)

c. SDG&E

Unlike PG&E and SCE, SDG&E did not automatically include all of the pending resources in its base case resource plan. Rather, SDG&E reviewed each pending resource on an

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27 Concurrent Brief of Southern California Edison on Resource Planning Issues and the Iterative Cost-Effectiveness Methodology (SCE Brief), December 22, 1989, pp. 4-5.

individual basis to determine whether or not it should be reclassified as "committed" or tested for cost-effectiveness as a potential resource addition.[28]

As described in Section III.A.2. above, SDG&E reclassified the new SO2 contracts as committed resources. All other pending resources were removed from the ER7 data set. SDG&E then subjected the South Bay 3 Augmentation and CT Inlet Air Coolers Retrofit projects to the ICEM analysis.[29] In its brief, SDG&E suggests that one or more of these resources may justify a finding of nondeferrability. If such a showing is made in Phase 1B, SDG&E recommends that those resources should be included in the resource plan. (SDG&E Brief, pp. 41-42.)

d. <u>DRA and CEC</u>

According to DRA, a strict interpretation of previous Commission decisions and rulings would exclude all pending and nondeferrable resources from the barebones resource plan. (Exh. 24, pp. II-3 to II-5.) Similarly, CEC acknowledges that pending resources do not meet the definition of existing and committed resources, as those terms have been defined by prior Commission decisions and by the joint efforts of the CEC and CPUC staffs. (CEC Brief, pp. 2-3, 9.) Nonetheless, both parties urge the Commission

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28 SDG&E's planning territory is the same as its service territory, i.e., no Muni resources or loads are considered. As a result, the issue of how to treat pending Muni resources did not come up for SDG&E; nor did SDG&E comment on this issue.

29 In its brief, SDG&E argues that the remaining pending resource, the PGE Storage Contract renewal, cannot be considered a potential resource addition because "PGE is under absolutely no obligation to extend the existing storage agreement beyond 1998." Therefore, SDG&E simply removes the renewal portion from the barebones resource plan, and does not consider it further. See <u>Concurrent Brief of San Diego Gas & Electric on Phase 1A</u> (SDG&E Brief), December 21, 1989, p. 41.

to selectively include some of these resources in the base case resource plan.

Specifically, DRA and CEC argue that the base case should include all pending Muni resources, QF projects, and the ACE demonstration project (in SCE's service territory), but exclude all pending IOU projects and contracts. Both recommend that the Commission examine any uncertainty or changes in the status of pending resources during Phase 1B.

With regard to Muni resources, CEC points out that the data sets for PG&E and SCE include various Muni utilities that own and operate their own resources. Including the pending Muni resources is therefore a necessary modelling convention to isolate IOU resource needs, in CEC's opinion. Both DRA and CEC agree with PG&E that the Commission should defer to CEC's expertise regarding the likelihood of Muni resources developing, and their independence from IOUs. (Exh. 24, p. II-8, TR at 583.) Moreover, DRA contends that it would be improper if IOU utility ratepayers ended up paying QFs based on the need for resources to serve Muni loads. (TR at 581.)

As a general principle, DRA argues that all pending QF projects should be included in the base case because the CPUC has already sanctioned the standard offer contracts and, for CEC jurisdictional projects, QFs seeking certification at the CEC have historically had a very high success rate. (Exh. 24, p. II-9.) CEC concurs with this position, asserting that excluding these projects would prejudge the outcome of its own approval process. (Exh. 28, p. 9.) However, in their brief, CEC and DRA recommend that three of the pending QF projects be deleted from the base case, based on more updated information regarding the status of these projects.[30]

DRA further recommends that the ACE demonstration project be included in SCE's base case resource plan, noting that it is under construction and has CEC approval to operate beyond the demonstration phase. CEC concurs.

For pending IOU projects and contracts, however, DRA and CEC propose alternative treatment. They recommend that these resources be excluded from the base case, absent a showing by the respondents that they are cost-effective and nondeferrable by QFs. With regard to IOU projects, DRA argues that these resources have not yet been determined to be needed and in the best interest of ratepayers since, by definition, they have not been certified or may have been only conditionally certified.

DRA and CEC recommend similar treatment for contract contingencies/rollovers of existing contracts, MOUs or pending executed IOU contracts awaiting regulatory action. DRA claims that including such contracts and/or MOUs in the resource plan allows for "regulatory leapfrog" in which QFs are not allowed to compete against contracts executed between updates. (Exh. 4, p. II-11.) Moreover, CEC argues that the respondents have offered no reason why these contracts cannot be subjected to the ICEM and the Commission's nondeferrability criteria. (CEC Brief, p. 17.)

e. SF/U/F and IEP/IPC

SF/U/F and IEP/IPC, on the other hand, argue that none of the pending resources should be included in the Phase 1A analysis. In their view, these resources do not comply with the CPUC's definition of barebones, i.e., existing and committed

30 These are: the two QFs in SDG&E's service territory that dropped out of the S02 solicitation (See Section III.A.2. above) and the Harbor/Chaplin project in SCE's planning area, which does not currently have a signed contract (See TR at 946-948).

resources only. IEP/IPC argues that it is inappropriate for the Commission to abandon recent decisions by simply accepting the conflicting definitions that appear in ER7. In IEP/IPC's opinion, using the barebones resource plan establishes an identifiable point of departure from which to assess uncertainties and determine potential resource needs in Phase 1B.[31] Moreover, SF/U/F and IEP/IPC argue that inclusion of pending resources in the barebones plan distorts the ICEM analysis, by introducing speculation about the emergence of future resources. SF/U/F points to the Harbor/Chaplin project, which was withdrawn during hearings, as evidence of the fundamental uncertainty of this resource category.

C. <u>Nondeferrable Resources</u>

ER7 defines nondeferrable resources as: "future cost-effective resources which for safety, environmental, technical, or other demonstrable reasons should be completed and not avoided by other resources such as QFs".[32] In ER7, the CEC determined that two kinds of resources should be considered nondeferrable. The first, referred to as "uncommitted conservation" or "demand-side management" (DSM) programs, consists of anticipated energy savings and demand reductions that would result if the Commission continued to fund existing conservation and load management programs at their present levels. Statewide, the CEC projects that these measures will save 1,550 MW and 1,533 gigawatt hours (gWh) by 1992 and 3,510 MW and 5,166 gWh by 1999.[33]

The second consists of 1,000 MW of surplus capacity from the Pacific Northwest (PNW) that is available for purchase by the

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31 <u>Concurrent Brief of Independent Power Producers Association and Independent Power Corporation - Phase 1A Issues</u> (IEP/IPC Brief), December 22, 1989, pp. 12-13.

32 ER7, p. IV-16.

33 ER7, p. IV-18.

California IOUs on a short-term or "spot" market basis. The CEC allocated this spot capacity to the three IOUs according to their intertie shares.[34]

CEC, SCE, SDG&E, PG&E, and DRA recommend that the CEC's findings on nondeferrability be incorporated into the ICEM analysis for this update cycle. In particular, CEC contends that these resources were already found to be cost-effective and nondeferrable, consistent with this Commission's criteria, during the ER7 proceedings. In addition, CEC argues that parties should not have to duplicate in the BRPU the substantial record already considered in ER7. SCE, SDG&E, and PG&E concur. Moreover, PG&E claims that, at the April 7, 1989 PHC in A.82-04-44 et al., the assigned ALJ acknowledged that uncommitted DSM would be included in the Phase 1A base case.

While generally agreeing with the ER7 conclusions for this update, DRA recommends that, for Phase 1B, respondents be required to specifically address cost-effectiveness and the Commission's nondeferrability criteria for non-DSM resources. (Exh. 24, p. II-6.; DRA Brief, p. 6; TR at 597.) Similarly, SDG&E believes that the Commission should subject as many resources as possible to the ICEM test. It would not object to submitting the spot capacity purchases to such a test before including them in the base case. (SDG&E Brief, pp. 39-40.)

With regard to DSM, both CEC and DRA argue that the ER7 adopted savings should be treated as a minimum level. They urge

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34 PG&E 500 MW, SCE 400 MW, and SDG&E 100 MW. See ER7, p. IV-20.

the Commission to examine additional DSM efforts during Phase 1B.[35]

IEP/IPC also includes uncommitted DSM and PNW spot capacity purchases in the barebones plan for Phase 1A. However, IEP/IPC does not recommend that the Commission adopt the CEC's ER7 assumptions regarding nondeferrable resources. Rather, IEP/IPC recommends that, in Phase 1B, respondents be required to make resource-specific showings required by Commission orders in support of any nondeferrability claims. For similar reasons, SF/U/F recommends that these resources be excluded from the barebones resource plan for the Phase 1A ICEM analysis.

D. Discussion

As discussed above, the decision to include or exclude certain resources at the start of cost-effectiveness testing can have a major impact on the type and timing of deferrable resources and, in turn, on FSO4 prices. Moreover, it is a decision that forms an important conceptual component of our LRAC pricing methodology. As we described in Section II.D., we have refined and implemented the concepts of LRAC pricing in a series of Commission decisions. Before addressing the specific resource plan issues in this proceeding, we provide a chronological summary of our prior determinations regarding the issues of "commitment", "nondeferrability" and other aspects of what constitutes the appropriate starting point for evaluating resource additions.

1. Prior Commission Determinations

The issue of what to include in the resource plan was first raised during our consideration in A.82-04-44 et al. of various approaches for calculating LRACs. In Phase I of A.82-04-44

35 See Exh. 28, pp. 4-5. In addition, DRA recommends that the CPUC improve the integration of DSM into the resource procurement process by formally adopting the BPRU uncommitted DSM as a commitment to fund the programs in future general rate cases (GRC).

et al., several parties (including CEC) proposed costing methodologies that would include expected QF supplies in the resource plan. DRA and IEP objected to this approach, arguing that it would result in basing QF prices on QF's own costs, instead of utility costs (as required by PURPA).[36]

In D.85-07-022 we concluded that the price determined under our adopted LRAC methodology must be calculated "without including those QFs who are not in existence, but will be brought on-line as a result of that price."[37] We also recognized that, for signed QF contracts, an objective standard of what QFs will be counted in the long-run avoided cost calculation would be required.[38]

We next considered the issue of what to include in the resource plan during Phase II of our LRAC proceeding in A.82-04-44 et al., where we examined specific cost-effectiveness testing approaches for implementing the GRP methodology. During this phase of the proceeding, parties presented a diverse set of recommendations. The utilities recommended inclusion of a resource if, in their judgment, the resource was likely to be completed, whatever its current status.[39] PG&E, for example, recommended including all expected utility resource additions and expected future QFs in the resource plan. QF representatives, on the other hand, recommended including only existing and committed utility plants, QFs that were on-line, and QFs expected to come on line

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36 See D.85-07-022, mimeo. pp. 24, 39, 42, and 54-55.

37 Ibid. pp. 31, 54-55, Appendix A, p. 3, and FOF 25.

38 Ibid. p. 55, FOF 27. In D.86-05-024 (mimeo. p. 23) we directed utilities to use DRA's projections of the QF success rate in Exh. 201, which was based on information obtained from the QF Milestone Procedure.

39 D.86-07-004, mimeo. p. 53.

under existing contracts.[40] DRA and QF representatives argued that a resource should not be considered committed, and included in the resource plan, if it is not yet under construction or is awaiting major regulatory approval.

In D.86-07-004, our final Phase II decision, we rejected utility proposals for establishing broad categories of generically nondeferrable resources. Instead, we permitted them to make a showing of nondeferrability on a project-by-project basis:

> "This 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.)

In D.86-07-004, we also determined that FSO4 should be based on avoidable baseload and intermediate resources, while peaking resources should be considered "nondeferrable" by QFs.[41] With regard to the definition of "commitment", we stated:

> "Generally, we agree with Public Staff that a utility should not be considered 'committed' to a project for which construction has not started or major regulatory approvals are pending. Here again, however, we permit utilities to demonstrate 'commitment' (or the opposite) on a project-specific basis where these guidelines seem not to be dispositive." (D.86-07-004, mimeo. p. 84.)

We further clarified our position on commitment in response to SDG&E's petition for modification of D.86-07-004. In its petition, SDG&E argued that the decision "treats QF resources

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40 Ibid. pp. 40-42.

41 Ibid. p. 82. We reiterated this finding in D.87-11-024, mimeo. pp. 22-23.

as committed and nondeferrable by other projects upon contract execution by the QF, while non-QF resources may be deferred until they have received all major permits, are under construction, or have received special dispensation by the CPUC". In denying SDG&E's petition, we responded:

> "We think it's clear from D.86-07-004 that one component of the utilities' resource plan filings is to be the projected success rate during the forecast period of QFs under contract. In other words, the resource planning process expressly considers uncertainty regarding the total megawatts of QFs likely to be available. Our QF Milestone Procedure is another means of ensuring that utilities will not have to pass up attractive resource opportunities on the strength of phantom QFs." (D.86-11-071, mimeo. p. 18.)

There was further debate over the definition of committed and nondeferrable resources during the compliance hearings in A.82-04-44 et al. During hearings in December, 1986, parties submitted testimony on the treatment of negotiated power purchase contracts in utility resource plans. As noted in D.87-05-060, all parties agreed that the utility's resource plan should include, not only the plants that the utility owns, but also power generated by other resources, to the extent those other resources are contractually bound to supply and the utility is bound to purchase their output. The parties disagreed, however, on what constitutes a binding commitment for this purpose. As we described in that decision:

> "Public Staff and QF representatives argue that the only 'committed' purchases are those for which (1) a contract has been fully executed by both sides, and (2) the subject power plant is constructed or at least fully certificated by the relevant licensing authorities. The utilities all take a broader view of 'commitment'. PG&E argues that the resource plan should include 'reasonable' estimates of purchases, whether or not a contract exists,

> since many such purchases are made on a short-term or spot market basis. Edison proposes that a negotiated contract be considered 'committed' when '(1) the parties mutually intend to enter into an agreed upon transaction, (2) consideration has been identified and agreed upon, and (3) sufficient documentation exists to establish the basic terms of a power purchase sale or exchange between the parties...' At a minimum, Edison asks that utilities have the opportunity to demonstrate on a case-by-case basis that a negotiated contract is committed. Edison also says that the impact of regulatory certification on a seller's ability to construct its facility and become operational is already accounted for in the purchasing utility's projection of QF success rates." (D.87-05-060, mimeo. p. 48.)

In responding to these various viewpoints, we explained:

> "What underlies our concern about commitment is that a vague standard for inclusion of potential purchases in utility resource plans amounts to an imputation of cost-effectiveness to purchases from certain sellers that have not bound themselves to specific terms and may be unwilling or unable to agree on terms acceptable to the utility. Such an imputation can only work to strengthen the hand of these sellers. We believe that the appropriate place to account for the size and attractiveness of potential, but unsigned, power purchase contracts is in the utility's examination of uncertainties, using alternative scenarios and/or other approaches to quantify the impact of varying outcomes." (D.87-05-060, mimeo. pp. 48-49.)

We concluded that, in general, a negotiated contract must be fully executed before the utility includes that contract in the resource plan. However, we allowed the utility the opportunity to make a specific showing that a particular purchase is committed,

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We concluded that, in general, a negotiated contract must be fully executed before the utility includes that contract in the resource plan. However, we allowed the utility the opportunity to make a specific showing that a particular purchase is committed, "based on objective manifestations of mutual intent, identified and agreed upon consideration, and other appropriate documentation".[42]

We also agreed with SCE that certification requirements for power plants yet to be constructed are properly considered by the utility in weighing the likelihood of available energy from a particular seller. We stated that this should apply whether or not the seller is a QF. Finally, we determined that the utility applicant should be able to amend its resource plan, before the matter is taken under submission, to reflect a negotiated contract signed after the initial filing.[43]

As described in Section II.D.1. above, the CEC adopted its then current Electricity Report (ER6) in December, 1986. The utility compliance filings followed in March 1987. Per our directives in D.86-05-024 and D.86-07-004, these filings included the utility's resource plan under a CEC-based scenario. During the hearings that followed, several parties expressed concerns over the utilities' and CEC's assertion of "committed" status for certain resources.

In particular, parties objected to the inclusion of:

a. Forecasts of future QFs (including self-generation) not currently under contract;

b. Inclusion of certain power purchases and exchanges that had not been embodied in fully executed contracts or were awaiting regulatory approvals;

c. New IOU projects that had not yet commenced construction;

d. "Reasonably expected to occur" DSM programs that depend on future regulatory action (termed "Conditional RETO" by the CEC in ER6); and

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42 D.87-05-060, mimeo. FOF 34.

43 Ibid. p. 48, FOF 33, 35, and Conclusion of Law (COL) 14.

e. The treatment of Muni utilities' "residual" loads, i.e, how the resource plans accounted for projected loads of Muni utilities within the CEC supply planning areas for the IOUs.

Despite these differences, all parties generally agreed with our conclusion of no avoidable resources, as the term is used for purposes of FSO4. Nonetheless, parties noted that these concerns were likely to have a significant impact in the next BRPU (i.e., this one).

In the compliance decisions that followed, we addressed several of these issues.[44] In D.87-11-024, we reiterated our position that the resources in a utility's resource plan, <u>whether or not they are deferrable by QFs</u>, must be cost-effective. With regard to DSM, we determined that committed DSM programs are nondeferrable by QFs.[45]

For uncommitted DSM programs, we accepted the CEC's estimates in preference to SDG&E's position (under which no uncommitted DSM would be included in SDG&E's resource plan). However, we also noted that in the future, the level of uncommitted DSM included in the resource plans should depend on more definitive demonstrations that such programs constitute cost-effective supply options. We supported expected enhancements to the cost-effectiveness methodology, via joint CEC and CPUC staff workshops

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44 As described in D.88-09-026, we did not undertake a line-by-line dissection of the resource plans filed in the ER6 update cycle, or respond to every planning issue raised by the parties. This was unnecessary, given the general agreement that there was no need for an FSO4 solicitation. However, we explicitly cautioned parties that they should not interpret our failure to expressly criticize (or approve) any particular aspect of a utility's resource plan as an endorsement (or rejection) of how the utility handled that aspect. (See D.88-09-026, mimeo. p. 4.)

45 D.87-11-024, mimeo. pp. 19-20.

on revisions to the Standard Practice Manual, as the vehicle for these demonstrations.[46]

In D.88-09-026, we clarified our expectations for future BRPU proceedings:

> "The adopted CEC forecasts of uncommitted conservation should be presented by the CEC and reviewed by our staff and other parties in terms consistent with any enhancements developed in the joint CEC/CPUC staff workshops on integrated least-cost methodologies. Based on our review, we expect that we will consider some or all of the estimated uncommitted conservation as nondeferrable resource additions for purposes of final Standard Offer 4." (D.88-09-026, mimeo. pp. 22-23.)

In D.88-09-026 we also directed the CEC and CPUC staffs to work jointly to define each Commission's resource planning terminology. That assignment was made in an attempt to understand more clearly what methodological differences may exist between the CEC's Electricity Report planning process and our LRAC pricing methodology.[47]

In D.88-03-079, in response to criticisms of SCE's and PG&E's resource plans, we again reiterated our position that a

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46 Ibid. The term "uncommitted DSM" used in ER7 is synonymous with the term "conditional RETO" used by the CEC in ER6 (and by us in D.87-11-024).

47 D.88-09-026, mimeo. p. 20. The joint staff effort was summarized in the Joint CEC/CPUC Proposed Resource Accounting Terminology, (Exh. 10). We note that several parties referred to specific examples in this document in support of their position to include (or exclude) certain resources from the barebones resource plan. Such use of this document is inappropriate. The examples listed under the "existing and committed" category represent the view of staff only, and do not reflect (in all cases) our prior determinations. Moreover, some of the examples represent the types of resources that were not specifically considered in the compliance decisions in A.82-04-44 et al. and therefore will be addressed, for the first time, in today's order.

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:[48]

> "Nondeferrable generation resources don't belong in a resource plan unless they are shown to be cost-effective. To include such resources unfairly reduced 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." (D.88-03-079, mimeo. p. 5.)

Finally, in D.88-09-026, we concluded that, for purposes of the CEC-based resource plans, the utilities should adopt the treatment of residual Muni loads preferred by the CEC. With regard to the treatment of self-generation (i.e., as a reduction of demand or as a source of both demand and supply), we also deferred to the CEC.[49]

2. Conclusions

As described above, we have previously discussed, in some detail, what should (and should not) be included in the utility's resource plan before testing new resources for cost-effectiveness. While some of our determinations may require further clarification, many of them are straightforward and, consistent with the scope of this phase, should be followed without further debate. We will therefore address each of the resource plan issues raised in this proceeding with direct reference to our prior orders, where applicable.

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48 D.88-03-079, mimeo. COL 3. We made one exception to this rule, namely, hydroelectric projects proposed in the context of relicensing proceedings. (Ibid. p. 6.)

49 D.88-09-026, mimeo. p. 7.

Before turning to specific issues, however, we make two general observations. First, in addressing each specific issue in A.82-04-44 et al., we never lost sight of the overall purpose of our adopted LRAC methodology, which is "to create a pricing structure that captures to the extent possible the efficiency and other benefits of perfect competition in electricity generation."[50] As we stated in prior orders, our intent is to create a "level playing field" for consideration of all resource options, including utility-owned generation projects, interutility contracts, DSM and QF projects. Our basic approach is to establish the appropriate price signals, based on the utility's long-run marginal costs, which would encourage these outcomes.[51] Accordingly, our decisions today on specific issues will be, as they have been in the past, designed to encourage competition among resource options as well as between QFs and non-QF sellers interested in long-term supply contracts with California.

We recognize that the current state-of-the-art in LRAC pricing and bidding will require certain refinements to fully realize these objectives. Nonetheless, our adopted LRAC methodology goes a long way towards achieving consistency in utility resource planning decisions. Unlike other proposals we considered in A.82-04-44 et al., the GRP approach does not need to be varied depending on the purpose for which it is being used. As we stated in D.85-07-022, the method of calculating LRAC for QF payments should be the same as it would be for other utility

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50 D.88-03-079, mimeo. p. 29.

51 Our discussions in A.82-04-44 et al. is replete with references to the objectives of fostering competition and creating a "level playing field": See D.85-07-022, mimeo. pp. 49-50; D.86-07-004, mimeo. pp. 3, 45 (footnote 29), 61-62a, and 86; D.86-11-071, mimeo. p. 18; D.87-11-024, mimeo. pp. 10, 28-29; and D.88-09-026, mimeo. p. 6.

resource decisions.[52] We will keep this in mind as we consider various recommendations on what constitutes the appropriate starting point for the ICEM analysis.

Our second observation is that most parties to this proceeding fail to distinguish between the "barebones" resource plan and the "base case" plan or scenario.[53] The former is a methodological concept. It refers to those resources that are assumed in the utility's resource plan before testing candidate resource additions for cost-effectiveness. The latter represents a specific set of assumptions assumed to comprise the "most likely" scenario, including forecasts of demand, prices, and availabilities of the resources in the barebones plan, as well as the costs and operating characteristics of candidate resource additions.[54]

In other words, our consideration of proposals to modify the ER7 data set to comport with our definition of "barebones" does not, in any way, undermine our commitment to assign the CEC's Electricity Report assumptions great weight in this and future BRPU

52 D.85-07-022, mimeo. pp. 49-50.

53 Although we do not agree entirely with IEP/IPC's definition of "barebones", we note that IEP/IPC appropriately emphasized this distinction in developing its position on specific issues. (See Exh. 33, pp. 7-9.)

54 In their comments to the ALJ's Proposed Decision, PG&E and SDG&E argue that the ALJ's characterization of the base case as the "most likely" scenario is unfounded. We disagree with PG&E's and SDG&E's interpretation of our prior orders. We have repeatedly stated that the ER7 base case assumptions will be given great weight in our resource planning deliberations. In practice, this policy translates into ascribing a higher likelihood to the base case scenario than alternative assumptions and scenarios (even those considered to be most likely by respondents). This does not mean that we ignore the impact of uncertainty and strategic considerations. As described in Section VIII.A. below, we will incorporate those considerations into our FSO4 solicitation.

proceedings.[55] As we have stated in prior orders, utilities are required to present their base case scenarios for each BRPU using the demand and supply assumptions adopted in the CEC's most recent Electricity Report. And we intend to give the results of those base case analyses great weight in developing LRACs and FSO4 prices.

Our decision to use the CEC's assumptions for the base case does not, however, imply that we have changed our adopted LRAC pricing methodology, as SCE asserts. (SCE Brief, pp. 4-6.) SCE misinterprets our prior orders. We have never changed our philosophy concerning our adopted approach for calculating LRAC. Nor have we abandoned the basic concept of considering only existing and committed resources as the starting point for identifying cost-effective resource additions that are potentially deferrable by QFs. Rather, as the need arose, we have attempted to clarify what "commitment" means for various types of resources, such as utility-owned projects or interutility contracts. In addition, we have outlined specific criteria for a showing of nondeferrability, which includes a demonstration of project cost-effectiveness. Throughout the process of developing FSO4 prices, we have reaffirmed the underlying principles and methods of our adopted GRP methodology.

Indeed, we expected respondents to implement our adopted methodology in presenting their ICEM results in Phase 1A. As stated in the April 19 ALJ Ruling in A.82-04-44 et al., which was incorporated into this OII, respondents were to present a base case ICEM analysis of candidate resource additions, using ER7 demand and supply assumptions. The ruling specifically directed respondents and other interested parties to develop a barebones resource plan, consistent with this Commission's prior determinations, but using

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55 See D.86-07-004, mimeo. pp. 67-68.

all of the ER7 adopted demand and supply assumptions that would be needed to create the barebones plan.

PG&E and SCE did not follow these directives. Rather, they both used the ER7 data set "as is", without attempting to correct for any inconsistencies between the CEC's definition of barebones, relative to ours.[56] Both PG&E and SCE assert that the requirement to use ER7 assumptions for the base case was a requirement to include all pending and nondeferrable resources in the resource plan. We fail to see how PG&E and SCE could have interpreted our prior orders and the April 19 ALJ Ruling in this manner.[57]

It is incumbent upon SCE and PG&E, as respondents to this proceeding, to implement our orders in a complete and conscientious manner. If PG&E and SCE believed that our directives were ambiguous, they should have actively sought clarification prior to submittal of their filings. We put both SCE and PG&E on notice that we will accept nothing less than complete and conscientious implementation of our orders or of ALJ rulings in future phases of this proceeding.

a. Future QFs/Self-Generation

In our view, the plain reading of D.85-07-022 leads to a single, straightforward conclusion; namely, that future QF

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56 We note, however, that both PG&E and SCE proposed various modelling changes to the data set, as well as changes to the "existing and committed" categories. (See Exhs. 2 and 12.)

57 For the specific language contained in our OII, see Attachment 4, Appendix A, pp. 3-5; Appendix B, pp. 1, 5-6.

development under unsigned contracts should not be included in the resource plan when developing FSO4 prices.[58]

The PURPA principles that formed the basis of this conclusion in D.85-07-022 deserve repeating:

> "PURPA requires developing a QF price based on the utility's cost and not the QF's; the utility should pay QFs what the utility avoids by having some QFs come on line and provide power. It does not suggest that the QFs providing power to the utility be paid a price based on the costs that would have been avoided by the utility if all expected QFs provide power. Otherwise, the QF avoided cost rate will discriminate against both the QFs interested in signing contracts now and undetermined future QFs who are included improperly in the pricing determination. With expected QFs included as part of the resource plan, the utility can retire inefficient plants and the avoided cost will be based on a less expensive plant at the margin. This does not represent the marginal cost to the utility but for the QFs. The Staff GRP methodology does not have this potential problem. It gives the QFs an even-handed treatment with other utility resources and keeps the ratepayer indifferent to how the

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58 SCE cites D.86-07-004 to support its proposal to include future SO1 QFs in the resource plan. (Exh. 14, pp. 2-3.) We do not agree with SCE's interpretation. In D.86-07-004, we did characterize DRA's position as including forecasted QFs not under contract in the resource plan. (D.86-07-004, mimeo. p. 41.) However, the decision never directly states that this recommendation was adopted. Instead, in D.86-07-004, we adopt DRA's proposal for the ICEM, except for the inframarginality test. (D.86-07-004, mimeo. p. 83 and FOF 38.) As DRA points out in its brief, inspection of DRA's testimony shows that the recommendation to include future QFs was limited to the inframarginality test. (See Reference Exh. A in this proceeding, pp. 50, 97-110, and C-17.) Since the inframarginality test was not adopted, but the remainder of DRA's ICEM proposal was, the only inference that can be made from D.86-07-004 is that future QFs should not be included in the base case resource plan.

utility meets its customer demand."
(D.85-07-022, mimeo. p. 54.)

Including forecasts of unsigned SO1 and SO3 QFs in the resource plan would not only produce inaccurate avoided costs, but also, as DRA points out, would impute a policy preference, similar to a finding of nondeferrability, for as-available, short-run QF contracts relative to our long-run resource plan based offer. We do not, and never have, promulgated such a policy. Nor do we believe that such a policy would be beneficial to ratepayers. We concur with DRA that the price for energy and capacity under our FSO4, based on the cost of new resources, should be lower than the SO1 and SO3 prices would be.[59]

Moreover, we have consistently rejected proposals to include generic resources or unconsummated purchase power agreements in the barebones resource plan. In this respect, there is no real distinction between forecasts of future QF development, without signed contracts, and the types of generic resources that respondents included in their resource plan during the compliance phase of A.82-04-44 et. al. We are no more disposed today, than we were four years ago, to include these resources in the barebones resource plan in determining LRACs for FSO4 prices. Nor would we include these types of resources in calculating LRACs for other

59 As DRA explains in its brief, SO1 and SO3 prices are based on 100% of the utility's short-run avoided costs (SRACs), whereas FSO4 prices are based on the costs of a cost-effective resource addition (i.e., LRACs). Under the ICEM methodology, a potential resource addition should cost less than 100% of SRAC in order to pass the cost-effectiveness tests. Therefore, FSO4 prices should be lower than the forecasted SRAC payments to the SO1 and SO3 QFs. Moreover, if more than enough QFs subscribe to the FSO4 offer, our adopted bidding system would further reduce the FSO4 prices paid to winning QFs.

resource planning purposes.[60] For all of these reasons, we reaffirm the principle articulated in D.85-07-022 that forecasts of future QFs not under contract should be excluded from the resource plan in this and future updates.

With regard to self-generation, D.88-09-026 clearly states that the treatment of these assumptions (e.g., as a reduction in demand or as a source of both demand and supply) should follow the CEC's preference. However, we did not directly address the issue of how to differentiate between committed and uncommitted self-generation, as some parties urged us to do.[61] As we cautioned in D.88-09-026, our failure to expressly criticize (or approve) any particular aspect of a utility's resource plan was not intended as an endorsement (or rejection) of how the utility handled that aspect.

Accordingly, we consider this issue now, in the context of the ER7 BRPU cycle. As described in Section III.A.1. above, DRA argues that projections of future self-generation should be treated differently from projections of unsigned SO1 QF contracts. We disagree. The distinction between a potential self-generator and a potential as-available QF is a moving target at best. Under our as-available standard offers, QFs have the option

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60 For example, in evaluating the cost-effectiveness of a utility-proposed project, we would <u>not</u> start out the analysis by imputing the cost-effectiveness of future, uncommitted resources. Rather, we would create a barebones resource plan of existing and committed resources (as of that point in time), subject the project to cost-effectiveness testing, and compare those results with the results of a similar analysis for each project alternative.

61 For example, QF representatives urged the Commission to adopt specific guidelines excluding all future QF development, including self-generation, from the resource plan. See the Concurrent Briefs of Independent Power Producers Association, p. 40; PG&E, pp. 22-23; and CEC, pp. 16-17, filed on August 5, 1987 in A.82-04-44 et al.

of changing from simultaneous purchase and sale (i.e., no self-generation) to surplus sale (i.e., self-generation and sale of excess power) on a yearly basis. As described in D.82-01-103, this flexibility allows the QF to respond to changes in SRACs and retail rates.[62]

Hence, whether or not the project in question is operating as a self-generator, QF (or some combination of the two), the impact on the utility system is based on short-run pricing signals, which we update as frequently as every three months. We are unwilling to reserve a slot in the resource plan for these resources until they have signed contracts or are otherwise committed. As SF/U/F and IEP/IPC point out, no specific sites have been identified for these resources, and no development milestones were considered. For there reasons, consistent with our treatment of future QFs, we will exclude future self-generation additions from the barebones resource plan.

Specifically, for the Phase 1B base case, we direct respondents to use the CEC's short-run forecast for QFs with signed contracts, which extends through 1991. All post-1991 additions to as-available contracts should be set to zero, except for projects with negotiated deferrals, as reflected in executed amendments to their interim SO4 contracts. QF projects within the latter category should be included in the barebones resource plan. Respondents should include the CEC's estimates for self-generation additions through 1991. After 1991, all additions to self-generation should be set to zero.

These adjustments are designed to reflect the above determinations, namely, that unsigned QF contracts be excluded from

62 See D.82-01-103, mimeo. pp. 83-86; D.82-12-120, mimeo. pp. 74-75.

the barebones resource plan, along with projections of new self-generation.[63] We recognize that, for self-generation, the dividing line between "existing or committed" and "new" may be difficult to draw precisely. Our intent is to include only existing sites, or sites under construction, and corresponding estimates of self-generation levels. We expect that the methods for quantifying these amounts will be debated, as in the past, during the development of the CEC's short-run self-generation estimates in its Electricity Report proceeding. For the purpose of this update, we will adopt SF/U/F's recommendation that all additions to self-generation be set to zero beyond 1991, recognizing that, in future updates, the cut-off year may vary.

b. <u>QF Contracts</u>

As described in D.86-11-071 and D.87-05-060, QF projects with signed contracts are to be assigned a projected success rate, based on an objective standard, before including them in the barebones resource plan. The projected success rate is to account for the impact of regulatory certification on the QF's ability to construct its facility and become operational. While they may disagree on the specific assumptions, parties generally agree that the CEC's project-by-project approach for estimating short-run QF development comports with this requirement.

Our prior orders did not, however, directly address a situation where a standard offer solicitation has been issued, successful bidders are identified, but contracts have not yet been

63 During Phase 1B, parties may consider uncertainty with regard to the forecasts of "likely to develop" QFs under signed contracts, or "existing" self-generation. However, parties should not present sensitivity analysis showing the need for new additions with future self-generation additions or unsigned QF contracts included. These types of future resources should not be included in the barebones resource plan, base case or otherwise, in conducting the ICEM analysis.

signed. This was the case with the four SO2 contracts in SDG&E's service territory. (See Section III.A.2. above.)

IEP/IPC would exclude all of these projects, since, in their view, they do not qualify as committed (e.g., signed) contracts. We disagree. Unlike interutility MOUs or contracts under negotiation, a standard offer is a contract that is complete and available at the QF's sole option. Granted, it is not completely certain that the QF, once it wins the solicitation, will actually sign the contract. However, to assume that none of the successful QF bidders will sign an offer is, in our view, an extreme position. Moreover, it could lead to a situation where a subsequent bid cycle resolicits bids for all of the deferrable MWs that were identified in the previous cycle.

SDG&E, CEC, and DRA, on the other hand, would automatically include these projects, at an assumed 100% success rate, unless (and until) individual projects dropped out of the running. We disagree with this approach for two reasons. First, as described in D.86-11-071, even if the contracts were signed, we would not impute a 100% success rate. To do so would give QF projects preferential "commitment" treatment vis-a-vis other projects. Second, even if a QF tenders a successful bid, and thereby has the option of signing a standard offer, it could still decide, for a variety of reasons, not to do so.[64]

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64 In general, QFs have the option of withdrawing from a solicitation if the utility's interconnection study results in unacceptable costs or risks to the QF. In SDG&E's SO2 solicitation, where three of the four winning bids were from out-of-state QFs, the interconnection studies included an evaluation of potential "economic harm" and, depending on the outcome, possible additional curtailment provisions. One of the winning QF bidders (Bonneville) is currently negotiating with SDG&E over these provisions.

This was clearly the case for SDG&E's SO2 solicitation. At the request of the presiding ALJ, SDG&E presented an updated project status report during Phase 1A evidentiary hearings. (TR at 781, 782.) Two of the winning bidders, for projects totalling 52.2 MW, did not elect to pursue their projects. SDG&E and Bonneville Pacific Corporation (representing a 50 MW cogeneration project) are still negotiating a dispute over curtailment terms. To date, only one of the winning bidders has actually signed the SO2 contract with SDG&E (i.e., Luz Development for an 80 MW solar thermal project).

Clearly, the two projects that have dropped out of the solicitation should be excluded from the barebones plan. With regard to the remaining two active participants, some assessment of their successful development needs to be made before including them in the barebones plan. Unfortunately, none of the parties in this proceeding presented any estimates of these success rates.

For lack of more objective criteria, we will assume a 50% success rate for these two projects for the base case scenario. This represents a middle ground between the unacceptable extremes of 0% and 100%. As discussed in Section VIII. below, parties may consider the uncertainty of this estimate in their Phase 1B analysis.

Similarly, we will assign a 50% success rate to other QF projects with signed contracts that were designated as pending by the CEC. These are the Luz SEGS IX-XII solar units in SCE's service territory. The Harbor/Chaplin project, on the other hand, should not be included in the barebones resource plan. As CEC counsel described during evidentiary hearings, this project does not have a signed contract with any utility. It was included in CEC's pending category based on information from the developer that he might pursue negotiations with SCE for an expansion of his existing project. According to more recent information, the developer is now pursuing negotiations with LADWP. (TR at

946-948.) This project clearly does not represent a committed resource, and should not be included in the barebones resource plan.

In sum, for future FSO4 updates, respondents should project success rates for QF projects with signed contracts (or winning SO2 or SO4 bids) before including them in the barebones resource plan.[65] QF projects without signed contracts should not be included, unless the utility can make a specific showing to justify commitment. This approach is consistent with our treatment of interutility purchase power agreements (see below).

Contrary to CEC's assertions, we do not believe that our policy of including less than 100% of CEC jurisdictional QFs prejudges the outcome of the CEC's approval process. Nor does it undermine our own decisions to award standard offer contracts, as DRA and SDG&E suggest. Rather, as we explained in D.86-11-071, this policy is designed to take into account the less certain status of these resources which are committed in the contractual sense, but still may not materialize. Some of that uncertainty may, for certain projects, relate to uncertainty over the outcome of the CEC's siting review. To the extent that the CEC's Electricity Report process develops success rates for these types of contracts, we will use those estimates for our base case. If the Electricity Report process does not produce those estimates, we expect the respondents to develop them for their base case submittals.

65 This does not alter our previous determination that shortage costs for short-run QFs (SO1, SO2, and SO3) should be computed assuming the full subscription of FSO4. (D.86-07-004, mimeo. footnote 42; D.86-11-071, mimeo. footnote 2.)

c. Interutility (IOU) Contracts[66]

As described in D.87-05-060, our guidelines on the treatment of interutility contracts are straightforward: An interutility contract should be fully executed by both sides before including it in the barebones resource plan. However, we allow the utility the opportunity to make a specific showing that a particular purchase is committed, based on appropriate documentation.

In D.87-05-060, we explicitly rejected the position that executed contracts must also obtain all regulatory approvals before being considered committed. Rather, consistent with our treatment of signed QF contracts, the uncertainty associated with regulatory review should be accounted for in a projected success rate for each purchase.

In this update, PG&E included two interutility exchange agreements in its recommended base case resource plan: the Seattle City Light and Puget Sound agreements with BPA. The effective dates for these contracts are January 1, 1992 (Puget Sound) and December 1, 1993 (Seattle City Light).

PG&E has been negotiating transmission access with BPA for both of these contracts since August 1988, and does not yet have complete access to deliver the power. Transmission access must also be established before PG&E can seek approval from the Federal Energy Regulatory Commission (FERC). Since the effective dates of these contracts are 2-3 years into the future, PG&E's request to FERC will not be made until at least mid-1991 (for Puget Sound) and mid-1992 (for Seattle City Light). (TR at 47, 74, 894.) Although PG&E considers these contracts likely to go forward, PG&E

66 This section addresses IOU contracts only; the treatment of Muni resources (including pending Muni contracts) is discussed in Section III.D.2.e. below.

could not assess the probability of success to these (or any other) pending resources. (TR at 46-47.)

As described above, purchase agreements under negotiation do not satisfy our criteria for commitment. Moreover, the evidence fails to support a finding that these resources should be considered committed for other reasons. As DRA and CEC point out, the only other basis for including these resources in the barebones plan would be a finding of cost-effectiveness and nondeferrability. However, here again, PG&E provided no evidence to support this finding, and even testified that it would be difficult to do so before negotiations were completed. (TR at 78-79.)

As we discussed in D.87-05-060, including contracts under negotiation in the barebones resource plan amounts to an imputation of cost-effectiveness to purchases from sellers that have not bound themselves to specific terms, and may be unwilling or unable to agree on terms acceptable to the utility. This, in turn, puts competing resources, including QFs, at a competitive disadvantage, and may even strengthen the hand of the sellers. From a policy perspective, this creates undesirable incentives in the energy market, and undermines one of our major objectives for the QF bidding program.

For all of the above reasons, PG&E should exclude these two purchase agreements from the barebones resource plan. For the ER7 base case scenario, the firm energy associated with these agreements should be redesignated to nonfirm, consistent with Exh. 37.[67]

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67 As this exhibit illustrates, the firm energy associated with these two exchange agreements (and with spot capacity purchases) must be redesignated to nonfirm in order to arrive at the ER7 adopted levels for available energy from the Northwest.

In D.87-05-060, we indicated that utilities could consider the attractiveness of potential, but unsigned power purchase agreements, in their analysis of uncertainties. However, per ALJ Gottstein's November 14, 1989 ruling, we will examine the issue of how to enable QFs to compete with power purchase opportunities that materialize between updates during Phase 1B. (TR at 188-189.) Our determinations on this issue may, in fact, cause us to reconsider the treatment of unsigned agreements in alternative scenarios. For example, if a QF is allowed to bid for potential purchase opportunities that arise in between updates, then we might not consider alternative scenarios with potential purchase opportunities assumed "in" the barebones resource plan. Instead, we might subject these purchases to the ICEM analysis, and make available for bidding any purchase that passes the test. These interrelationships need to be explored by parties further, in Phase 1B, in developing their overall recommendations on how to treat power purchase opportunities.

Until we resolve these issues, we will treat purchase power agreements under negotiation as follows: If a utility does not believe it can reasonably estimate the final terms of contracts it is currently negotiating, it should remove those resources from the barebones resource plan for the base case scenario and all sensitivities. In other words, we will treat them in a manner similar to any future resource that is not far enough along in the development process to enable the utility to derive prices against which QFs could bid. We will establish the MW limit for this FSO4 solicitation without consideration of these resources, either in the barebones resource plan, or as potentially deferrable resource additions.

If, on the other hand, a utility believes that current negotiations are sufficiently mature to permit it to project prices for its Phase 1B filing, it should do so, and treat the unconsummated purchase option as a candidate resource.

Accordingly, these purchases will be subjected to the ICEM analysis and, if found to be cost-effective, considered to be deferrable by QFs (absent a convincing showing of nondeferrability).

We have, however, major concerns over the latter approach, given the lack of commitment on the part of potential sellers to adhere to the estimated terms and conditions of contracts undergoing negotiations. This raises the important policy issue of how to ensure that the final terms of the contract are consistent with the respondents' showings in this proceeding, if we do find that these purchases are nondeferrable by QFs. We will address this issue in Phase 1B.

d. <u>IOU Projects</u>

In D.86-07-004, we determined that, absent a specific demonstration of commitment, a utility should not be considered committed to a project for which construction has not started or major regulatory approvals are pending. Based on these guidelines, most parties now recommend that all pending IOU projects be removed from the resource plan and tested for cost-effectiveness. We concur.[68]

CEC and DRA recommend making an exception for the ACE demonstration project. They would include this resource in SCE's planning territory as a committed resource because it is currently under construction, and has CEC approval to operate beyond the demonstration phase. SCE argues that its Coolwater project should also be included in the resource plan, since it has recently completed a five-year demonstration.

We distinguish between a utility's commitment to a commercially viable project, to which our guidelines in D.86-07-004

68 We agree with SDG&E, however, that renewal of the PGE Storage contract in 1998 is highly uncertain at this time. For this reason, the renewal portion of the contract should not be evaluated as a candidate resource for this update.

apply, and commitment to a demonstration project.[69] By definition, a demonstration project may or may not become commercially viable (and cost-effective). Including a demonstration project in the barebones resource plan beyond the demonstration phase assumes that it will be both technically successful and cost-effective beyond the demonstration phase. This approach penalizes all other resource options, including QFs, that could compete using commercially available technologies.

Moreover, in many cases, IOUs will be purchasing power from these demonstration facilities, once commercial, under negotiated contracts with third parties.[70] As we discussed in Section III.D.2.c. imputing project cost-effectiveness in these situations creates undesirable market incentives.

In our view, the appropriate treatment for a demonstration project is to include it in the resource plan during the demonstration phase if it has received all regulatory approvals and construction has commenced. In other words, the commitment standard for a demonstration project should be the same as for a commercial project, but only during the demonstration phase. The utility will need to estimate what the project, in a demonstration mode, can reasonably be expected to contribute to energy and dependable capacity requirements during the demonstration phase.

Beyond the demonstration phase, the project should be evaluated as a potentially deferrable resource, and subjected to our ICEM tests of cost-effectiveness. Accordingly, SCE should exclude the Coolwater project from the barebones plan beyond its

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69 To our knowledge, the issue of how to define "commitment" for a demonstration project was never raised in A.82-04-44 et al.

70 This is apparently the case with the ACE Demonstration project. According to SCE, it is also negotiating to sell its Coolwater facility to another party. See SCE Brief, p. 16.

demonstration phase. For its Phase 1B base case filing, SCE may evaluate this project for cost-effectiveness using our ICEM methodology. As with any cost-effective addition, SCE has the opportunity to make a showing that this resource is nondeferrable by QFs, based on our adopted criteria.[71]

The ACE demonstration project, on the other hand, is a QF project owned by Kerr-McGee Chemical Corporation. Apparently, SCE has negotiated a long-run contract to purchase power from this QF beyond the project's demonstration phase. However, the record is not clear as to the status of this contract. If the contract is fully executed for the commercial phase then we consider this resource to be committed and would include it in the barebones resource plan, discounted by an appropriate success rate (see Section D.2.b. above)[72] For purposes of the base case, we would assign a 100% success rate to this project, given the fact that it has received all necessary permits and has commenced construction.

If, on the other hand, the contract between SCE and Kerr-McGee for the post-demonstration phase is not fully executed, then this project should be treated the same as the Coolwater project, as described above. Accordingly, within ten days from the effective date of this order, SCE shall file and serve on all parties to this proceeding a statement describing the status of its

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71 In its brief, SCE asserts that the Coolwater project has already completed its demonstration phase, and would pass the ICEM tests of cost-effectiveness. However, SCE failed to present any evidence or analysis of the project's costs, nor did it address our four-part test of nondeferrability. We will give SCE a final opportunity to do so in Phase 1B.

72 The record is also unclear as to the type of QF contract involved (i.e., standard or nonstandard). If it is the latter, our inclusion of the contract in the barebones plan would not impute a finding of reasonableness. Reasonableness issues are addressed in our Energy Cost Adjustment Clause (ECAC) proceedings.

contract with Kerr-McGee. Specifically, the statement should include the following information: (1) the date of contract execution, (2) the term of the contract, and (3) whether the contract is a standard offer or nonstandard contract.

e. Muni Resources

As described in Section III.D.1. above, in D.88-09-026 we determined that respondents should adopt the treatment of residual Muni loads preferred by the CEC. For this update, the CEC makes two related assumptions: (1) the IOUs have no additional obligation to meet the capacity and energy needs of the Muni utilities beyond the obligations imposed by existing contracts, and (2) Muni utilities will take steps to secure resources on their own to meet their future needs. Using these assumptions, CEC added enough pending resources to Muni service areas to balance Muni requirements. Accordingly, the pending Muni resources should be retained in each IOUs barebones resource plan, consistent with CEC's treatment of residual Muni loads.

As IEP/IPC points out in D.88-09-026, we also directed utilities to explore the risks of alternative assumptions in their showing on uncertainty and procurement strategy. However, in issuing that directive, we had not fully considered the implications of basing IOU avoided costs on the need for resources to serve Muni loads. In effect, SCE's and PG&E's FSO4 payments to QFs would reflect the future resource needs of Muni utilities if pending Muni resources were excluded from the barebones resource plan. We agree with DRA that IOU ratepayers should not pay QFs based on Muni utility needs, unless the IOU is contractually obligated to meet those needs. Therefore, we direct respondents to use the above assumptions (and include all pending Muni resources in the barebones resource plan) throughout the Phase 1 analysis of LRACs and QF deferrable resources.

f. <u>Spot Capacity Purchases</u>

During the compliance hearings in A.82-04-44 et al., we addressed the issue of how to treat spot market purchases. In response to PG&E's position, we stated that such purchases should be excluded from the barebones resource plan, but may be accounted for in the utility's examination of uncertainties. Again, our reason for taking this approach was to ensure that non-QF sellers to the California market are encouraged to compete with other resources, including QFs, rather than being guaranteed a preferential slot in the utility's resource plan.

We note that several parties support the CEC's assessment that these resources are nondeferrable. However, in making its findings, the CEC did not subject these resources to the ICEM. Nor could it have constructed a barebones resource plan, consistent with our determinations today, in order to do so. We agree with DRA and SDG&E that as many resources as possible should be subjected to the ICEM tests of cost-effectiveness.

Therefore, for their Phase 1B filings, respondents should exclude spot capacity purchases from the resource plan, absent a utility showing of cost-effectiveness and nondeferrability. In making such a showing, respondents should rely on ER7 assumptions concerning the availability and costs of these resources, as reflected in the ER7 data sets.[73] Consistent with Exh. 37, the firm energy associated with these purchases should be redesignated to nonfirm when they are removed from the base case barebones resource plan. Alternative assumptions may be considered in the Phase 1B evaluation of uncertainties.

73 In addition, respondents will need to estimate the fixed charges associated with these purchases, and include those charges in their cost-effectiveness evaluation. For the base case scenario, respondents should use the estimates provided in the ER7 documents.

We have, however, similar concerns regarding these purchase opportunities as we do for contracts currently under negotiation. There is no guarantee that sellers in the PNW will make these purchases available, at favorable terms, in the future. Moreover, we do not have adequate information on these types of purchases, their quantities, prices, and availabilities, on an ongoing basis, in this or other proceedings at the Commission. This information would aid us in assessing the uncertainty associated with these purchases in future update proceedings. Accordingly, commencing on August 1, 1990 and until further order by this Commission, respondents will be required to file quarterly reports on the quantity, price, and terms of any spot firm capacity purchases made during the previous quarter. These reports shall be filed with the Commission's Docket Office on February 1, May 1, August 1, and November 1 of each year, and served on all parties to this proceeding.

g. Uncommitted DSM

As described in prior orders, cost-effective uncommitted DSM is nondeferrable by QFs. Most parties to this proceeding recognize that current procedures result in different cost-effectiveness tests for generation resources on the one hand, and conservation and load management programs on the other. Specifically, generation resources are tested using the ICEM tests of cost-effectiveness, while DSM is evaluated using several tests, including a measure of rate impacts on the nonparticipating ratepayers.[74] These tests were developed, and are described, in the joint CEC/CPUC Standard Practice Manual.[75]

While some progress via informal workshops has been made to improve the consistency of these tests among resource options, we have not yet fully integrated our cost-effectiveness testing methods for supply- and demand-side resources. Apparently, the informal workshop process encouraged in our compliance decisions in A.82-04-44 et al. has come to a standstill. (TR at 620.) In order to further this process, in Phase 1B we will explore the feasibility and relative advantages of subjecting specific DSM programs to our ICEM methodology, using SDG&E's system as a test case. (See Section VIII.B. below.)

Before addressing a broader range of integration issues, we need to fully consider the recommendations of the Statewide Collaborative Process (Collaborative) on energy efficiency, as well as the utility-specific proposals for pilot

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74 In contrast to most supply options, DSM programs cause a direct shift in revenues, which affects rates. Under many conditions, revenues lost from DSM programs have to be made up by ratepayers through increased rates. In addition, unlike supply options, a utility usually invests only a fraction of the costs associated with a demand-side resource, with program participants investing the remainder. As a result, the participating ratepayer faces a different stream of costs and benefits than the utility, the nonparticipating ratepayer, and society as a whole. For these reasons, we have found it necessary to consider, and balance the results of a variety of tests, each designed to reflect these various perspectives.

75 This manual was originally published in 1983, under the title of Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs. In December 1987, a second edition of the Standard Practice Manual was published jointly by the CEC and CPUC staffs. This version is entitled Standard Practice Manual, Economic Analysis of Demand-Side Management Programs.

shareholder incentive mechanisms.[76] It is therefore premature to consider in Phase 1B DRA's proposal to link program funding commitments to the levels of uncommitted DSM adopted in this proceeding. Instead, we will schedule consideration of DRA's proposal for Phase 3 of this proceeding, or whatever proceedings may follow from the collaborative process.

In the meantime, as we stated in D.87-11-024, we expect the CEC to present its adopted forecasts of uncommitted DSM for review by DRA and other parties, in terms consistent with the interagency staff enhancements to the Standard Practice Manual. We have reviewed ER7 and the record in this proceeding, related to DSM cost-effectiveness testing.[77] Based on that review, we conclude that the CEC's projections were developed in a manner consistent with the cost-effectiveness criteria contained in the Standard Practice Manual. Accordingly, we will include those amounts in the base case. Alternative levels of cost-effective uncommitted DSM may be considered in the Phase 1B evaluation of uncertainties.

h. Additional Base Case Modifications

Several additional modifications to the CEC base case were proposed by various parties. SCE recommends that its Castaic exchange contract with LADWP and Chino battery storage project be considered committed and included in the base case resource plan. Although ER7 included the SCE/LADWP Castaic exchange contract as a

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76 The Collaborative was formed in July 1989 by 15 parties with a stake in energy efficiency, including utilities, nonprofit public interest groups, and providers of alternative energy services. In January 1990, the Collaborative presented its consensus proposals to the Commission, in An Energy Efficiency Blueprint for California. The next step of the process is to consider the March 1990 utility-specific filings and address the Collaborative's consensus (and nonconsensus) policy principles outlined in the January 1990 report.

77 ER7, Appendix C, pp. C-38, C-44, Exh. 28, p. 3; TR at 619.

pending resource, SCE claims that it is committed, having been in effect since May 8, 1988. According to SCE, the 10 MW Chino battery storage project is currently being demonstrated as a pumped storage unit, and was improperly omitted from ER7 supply assumptions.

In addition, SCE recommends that the Axis steam plant and CT resources be added under existing resources, and that the Blythe load be incorporated into the demand forecast. SCE asserts that these resources and loads were integrated with SCE's main system when the Blythe-Eagle Mountain interconnection was closed on October 31, 1988.

PG&E recommends that an additional 62 MW of QF geothermal resources be included, claiming that this amount was identified in ER7, but inadvertently omitted from the ER7 data set. SDG&E recommends that the additional DSM authorized in its most recent GRC proceeding be added to the CEC's committed amounts. In addition, CEC recommends that Rancho Seco be removed from ER7 supply assumptions, consistent with its proposed resource plan modifications for SCE and PG&E.[78]

None of these proposed modifications was contested by parties to this proceeding. We therefore consider them to be reasonable adjustments, with three qualifications. First, PG&E

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78 ER7 included this resource under "existing" resources. However, on June 6, 1989, Sacramento voters rejected a proposal to allow the Sacramento Municipal Utility District (SMUD) to continue operating Rancho Seco. On September 1, 1989, the ER7 Standing Committee issued its recommended changes in the ELFIN data sets to reflect the shutdown of Rancho Seco. According to the CEC, the removal of Rancho Seco would result in a temporary increase in power purchases from SMUD under existing contracts with SCE and PG&E. (See the CEC's Recommended Changes in the ER7 ELFIN Data Sets to Reflect the Shutdown of Rancho Seco, filed September 1, 1989 in this proceeding.) PG&E subsequently filed a revised ICEM analysis to reflect these changes. (See Exh. 3.)

should include the additional 62 MW of geothermal resources only to the extent that these additions do not include future QF/self-generation additions after 1991. Second, consistent with our treatment of the Coolwater project, SCE should exclude the Chino Battery Storage project after its demonstration phase, subject to a showing of cost-effectiveness and nondeferrability, as we described in Section III.D.2.d. above. And finally, SDG&E should adjust committed DSM amounts by the figures presented in Exh. 24, which appropriately account for the fact that some of the GRC programs have already been included in the ER7 data set.

E. Summary

In Table 3, we summarize our specific findings for this BRPU cycle regarding the treatment of ER7 pending and nondeferrable resources for all three respondents. Table 3 also indicates any changes to the ER7 data set that we adopt for the "existing and committed" category, based on the project-specific showings made during Phase 1A. For Phase 1B, the "barebones" resource plan will consist only of those resources so identified in Table 3. These determinations will not vary for alternative scenarios, or sensitivities. For the base case scenario, all parties should construct their barebones resource plan using the ER7 corresponding demand and supply assumptions.

Figure 1 presents a generic summary of how we define commitment (and barebones) for this and future updates. It also describes the types of resources that should be subjected to the ICEM tests of cost-effectiveness and considered potentially deferrable by QFs. Finally, Figure 1 identifies some of the types of alternative assumptions that may be considered for the Phase 1B sensitivity analyses. We discuss this issue in greater detail in Section VIII.A.

Consistent with our prior orders, in each update we will permit utilities to demonstrate commitment (or the opposite) on a project-specific basis where these guidelines seem not to be dispositive.[79] In future updates, we will also continue our practice of developing a base case scenario using the most recent CEC Electricity Report assumptions.

As described in D.86-07-004, utilities are permitted to make a four-part showing of nondeferrability on a project-by-project basis. This showing must (1) establish the project cost-effectiveness, (2) set forth the aspects of the project claim 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. Wherever possible, we expect utilities to use the full ICEM approach in evaluating project cost-effectiveness.

We also determined in D.86-07-004 that peaking resources are (by definition) nondeferrable by QFs.[80] In D.88-03-079, we granted PG&E's request to treat hydroelectric relicensing improvements as generically nondeferrable by QFs. As we discussed in Section III.D.2.g. above, cost-effective uncommitted DSM programs, as determined using the Standard Practice Manual tests, are also nondeferrable.[81] In Phase 1B, any party claiming that a resource is nondeferrable must make the requisite showings.

79 For this update cycle, Phase 1A provided respondents the opportunity to make specific showings on commitment. We will not revisit the status of resources in Phase 1B unless, as we indicated in D.87-05-060, a utility executes a contract that was previously under negotiation.

80 We discuss the issue of what constitutes a "peaker" in Section VI.C. below.

81 Further consideration of how to integrate demand- and supply-side resources may, however, alter our current approach for evaluating the cost-effectiveness of these programs.

IV. Modelling Issues

During Phase 1A, parties recommended specific modelling changes to the ER7 data set. These recommendations raised the following generic issues for our consideration:[82]

(1) Whether (and how) to capture the value of reduced payments to variable-priced QFs in the ICEM analysis;

(2) How to account for the CEC's "age-deration" amounts in production costing and ERI calculations;

(3) How to model the availability of standby units in production costing and ERI calculations;

(4) How to model units that can be cycled on a daily basis;

(5) How to model as-available QFs; and

(6) How to incorporate variable operation and maintenance (O&M) costs into the ICEM analysis.

These issues are described and discussed in greater detail below.

A. Payment Reductions to Variable-Priced QFs

All QFs with SO1, SO2, and SO3 contracts, as well as those with interim SO4 contracts after the fixed price period (and, under certain payment options, during the fixed price period), are paid a variable energy price.[83] As discussed in Section III.D.2., these QFs are included in the utility's barebones resource plan, at

82 Modelling issues regarding differences among models were not raised in Phase 1A, since all parties used the same production cost model (ELFIN) to conduct their ICEM analysis.

83 In addition, under our FSO4 offer, QFs that come on-line during Period 1 (i.e., before the on-line date of the deferred resource) are paid variable energy prices.

projected success rates. By far the most controversial modelling issue that emerged during Phase 1A relates to the treatment of payment reductions to these QFs. More specifically, parties disagree over whether or not the value of reduced payments to variable-priced QFs should be considered in evaluating the cost-effectiveness of potential resource additions.[84]

Variable-priced QFs are paid for the energy they produce based on the utility's SRACs, that is, the incremental costs of the system assuming that the utility cannot change its current resource plan. SRACs are derived by comparing a production simulation of the utility system including variable-priced QFs with a simulation excluding those QFs (the "QF-in/QF-out" method).

The addition of a cost-effective new resource will typically reduce a utility's SRACs by reducing the utility's use of its most inefficient power plants. This, in turn, reduces the energy payments paid to variable-priced QFs.[85] These payment reductions are attributed to the new resource addition, and improve its cost-effectiveness.

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84 Of all the modelling issues explored during Phase 1A workshops, this one also appeared to have the largest potential impact on ICEM results. (See Exh. 9, pp. 11-12.)

85 More specifically, variable energy payments equal the product of the Incremental Energy Rate (IER) and the price of the avoided fuel. Avoided fuel prices are updated every quarter, based on our latest projections of the marginal fuel and the most recent quarter's actual cost of that fuel. It is the IER component of variable energy payments that is derived from the production cost comparisons described above. The total cost difference between the QFs-in and QFs-out runs, divided by the total kWhs of QF generation all divided by the estimated incremental fuel price, yields an IER (in Btus/kWh). Hence, the IER represents a "derived" marginal heat rate of the system. The addition of a new cost-effective resource improves the efficiency of the system (i.e., reduces the marginal heat rate), thereby reducing SRAC payments to variable-priced QFs. For a detailed discussion of energy pricing for variable-priced QFs, see D.88-03-079, mimeo. pp. 21-34.

1. Position of the Parties

Respondents recommend that the Commission adopt a modelling convention to exclude reductions in QF payments from the ICEM.[86] PG&E argues that, at some point, the utility would have added a candidate resource addition to substitute for the short-run QFs removed in the QF-out simulation. This would effectively "cap" SRACs at the utility's LRACs, and eliminate any of the QF price reductions observed when a candidate resource is being tested for cost-effectiveness. To let SRACs increase without such a cap would, in PG&E's opinion, violate the principles of avoided cost pricing. PG&E believes that the Commission anticipated the need to adopt this approach in its discussion of QF pricing in D.88-03-079.

SDG&E argues that reductions in QF payments are a secondary effect that should not justify the addition of resources. Similarly, SCE characterizes these reductions as a pure transfer of revenue from existing QFs to the QF operator of the identified deferrable resource (IDR). In SCE's view, unlike production savings from more efficient system operations and increased reliability, these types of cost reductions are of no net benefit to society. Moreover, SCE argues that inclusion of these cost reductions in the ICEM would violate least-cost planning principles, and could cause the utility to overbuild. Finally, SCE asserts that the reduction in QF prices is speculative because there is no direct link between any BRPU ICEM results and actual utility costs.

In contrast, DRA and IEP/IPC recommend that QF price reductions be included in the ICEM analysis.[87] DRA argues that,

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86 None of the respondents, however, propose that the method for calculating SRACs, and deriving prices to variable-priced QFs, be changed at this time.

87 SF/U/F and CEC did not express a position on this issue, either in direct testimony or briefs.

in D.88-03-079, the Commission explicitly rejected the "substitute resource" approach that PG&E assumes will be used to calculate SRACs sometime in the future. Moreover, DRA asserts that there is no indication from D.88-03-079 that the Commission intends to reconsider this approach as a replacement for the QFs-in/QFs-out method.

In response to SCE's arguments, DRA claims that fuel savings are also a transfer from one entity to another (i.e., money that would otherwise go to fuel suppliers is transferred to developers of a resource). DRA argues that there is no conceptual difference between the two types of transfers, and they should be treated equally. Nor are the QF savings any more speculative than the forecasts of fuel, demand, and other variables used in doing a 20-year forecast, in DRA's opinion. In support of its position, DRA also describes various precedents for including this type of savings in the cost-effectiveness analysis.

Both DRA and IEP/IPC acknowledge that implementing the QF-in/QF-out method for each iteration of the ICEM analysis would require running at least twice as many production simulations and be extremely burdensome to implement. To reduce this modelling effort, IEP/IPC recommends pricing the QFs at marginal cost (QF-in) for an initial screening. If a resource is identified as a cost-effective addition in a given year, IEP/IPC recommends that a QF-in/QF-out iteration be performed to check the results. DRA, on the other hand, recommends just pricing QFs at marginal cost (QF-in), given the complexities of performing the QF-In/Out simulations.

2. Discussion

In D.88-03-079, we adopted the QF-in/QF-out method for calculating energy payments to variable-priced QFs. In that decision, we considered the theoretical argument that this method should be modified to account for any long-run resources that a utility would substitute for short-run QFs if they were all removed from its system. As DRA points out, however, we explicitly rejected modifications along the lines now suggested by PG&E.

In rejecting the substitute resource approach we noted that the need to modify the QF-in/QF-out approach may never materialize, as the electricity market evolves such that utilities and QFs compete on more even footing. If these changes occur, we stated that we would reconsider the "QF-in" approach. We also observed that the substitute resource approach involves fairly complex and hypothetical manipulations of utility resource plans.[88]

In short, contrary to PG&E's assertions, we gave no indication that our approach to short-run marginal cost pricing would change in the foreseeable future. For the purpose of establishing LRACs in this update, we anticipate that prices to variable-priced QFs will continue to be affected by a utility's resource planning decisions, and those changes (up or down) will be passed through to ratepayers. As DRA points out, we have routinely included the effect of adding a new resource in the calculation of QF prices. (DRA Brief, pp. 21-22.)

Respondents argue that the interrelationship between utility resource decisions and SRACs should be ignored for the purpose of evaluating resource cost-effectiveness. We disagree. There are precedents for including these types of ratepayer savings in the cost-effectiveness analysis of resource options. In the Devers-Palo-Verde 2 transmission line proceeding, for example, the cost-effectiveness analysis presented to the Commission by DRA and SCE contained the estimated savings due to reduce QF payments.[89]

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88 See D.88-03-079, mimeo. pp. 27-28, 32-34. ✓

89 See D.88-12-030, Appendix B, pp. 8-15. ✓

QF payment savings are also being included in the study of the COTP. (TR at 469-470.)

More importantly, respondents fail to recognize that all ratepayers directly benefit from these price reductions, in the form of lower rates, regardless of what transfers may occur between various cohorts of QFs. Since we evaluate LRACs from the perspective of the ratepayer, not the utility planner or shareholder, inclusion of these benefits is appropriate.

We also disagree with SCE's position that QF payment savings do not provide any societal efficiencies. (TR at 303.) As DRA points out, in order to be cost-effective, the new resource (or FSO4 QFs that defer the new resource) must be less expensive than the SRAC prices paid to variable-priced QFs before the resource was added. Because it must be less expensive to compete, that new resource (or FSO4 QF) will generally be more efficient.

Further, existing QFs must operate in a more efficient manner in order to maintain their profitability. Thus, the lowering of payments to existing QFs may remove the least efficient operators and force the remainder to improve their efficiency.[90]

For the reasons discussed above, we direct respondents to include QF pricing effects in their Phase 1B ICEM analysis of resource options. If and when we consider modifying our SRAC methodology, we will revisit this issue. To implement this requirement, respondents should set the cost of energy from variable-priced QFs equal to the utility system's marginal costs (QF-in).

Although this approach is less precise than performing both QF-in and QF-out simulations, it is considerably less complex and cumbersome to implement for the Phase 1B filings (see Section VIII. below). Moreover, based on respondents' January 19

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90 DRA Brief, p. 20, TR at 450.

and February 2, 1990 filings, the ICEM results appear largely unaffected by the additional QF-out simulations. The QF-in/QF-out approach changed the year in which a resource passed the first-year test in only two instances for PG&E, and one for SCE.[91] There were no differences in results for SDG&E.

B. Age-Deration

In ER7, the CEC concluded that the amount of capacity that could be expected from aging oil/gas plants will decline as the plants get older. To reflect this reduction in available capacity, the CEC decided that a certain total amount of age-derated capacity was to be removed from each utility's resource plan.[92] The CEC adopted a methodology that assumes a linear decline from full rating to zero as plants go from 35 to 60 years of age. Based on this methodology, the CEC estimates a total of 1,397 MW of age-deration for PG&E by the year 1999, 1,079 MW for SCE, and 273 MW for SDG&E.

However, ER7 did not explicitly state how age-deration should be incorporated into the resource plans and production cost models used to do cost-effectiveness analyses. All parties assumed that the age-derated capacity was not available when determining reserve margins, ERIs, and shortage values. However, there were many different assumptions regarding how age-deration should be incorporated into production cost models, and the resulting system fuel costs and avoided energy values.

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91 We note that the direction of the change in results varied. In PG&E's case, the QF-in/QF-out iteration delayed the cost-effectiveness of a CT (i.e., moved it from being cost-effective in 1996 to 1998), whereas in the other two instances the QF-in/QF-out iteration made the resource cost-effective in an earlier year. See PG&E Second Phase 1A Resource Plan Filing, January 19, 1980, Figures 2 and 3; Filing of SCE on the BRPU, January 19, 1980, Table 12.

92 ER7, pp. V-8 to V-16.

During evidentiary hearings, the assigned ALJ ordered parties to discuss these differences in a workshop setting, and possibly develop a consensus on how to treat age-deration for this BRPU update. On November 27, 1989, PG&E, SCE, SDG&E, DRA, CEC, and IEP/IPC submitted a workshop report (Exh. 36), which summarized the various assumptions used in their original filings and an agreed-upon approach for incorporating age-deration into the ELFIN data set.[93] The consensus was to incorporate age-deration in the calculation of the ERI. For this purpose, the utility would first count its standby units towards the required age-deration levels.[94] It was also agreed that age-deration should not be incorporated into the production cost simulation.

We will adopt this approach as reasonable for this BRPU cycle. However, we may choose to revisit this issue in future updates, should the CEC continue to incorporate age-deration in Electricity Report findings concerning unit availability.

C. Treatment of Standby Units

Standby units are oil and gas plants that are potentially available for operation, but generally require additional expenditures and/or start-up time before they can be placed into service. IEP/IPC raises the issue of how to treat standby units for production costing and capacity valuation purposes. Specifically, IEP/IPC argues that all standby units should be removed and checked for cost-effectiveness before being included in the resource plan.

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93 SF/U/F did not express a position on this issue.

94 In other words, the capacity associated with standby units would not be "removed twice" from the calculation of reserve margins or ERIs. This type of double-counting was apparently a problem with IEP/IPC's calculations.

However, IEP/IPC fails to recognize that we have previously drawn a clear distinction between short-term reserves (i.e., standby units that can be restarted in a short time with little or no expense) and long-term reserves (i.e., standby units that require significant time and investment to place into daily operation). In recent ECAC proceedings, we have determined that short-term reserves should be modelled as being available over the entire forecast period, when determining the short-run need for capacity and for production costing purposes.[95] We see no reason to exclude these resources for our long-run avoided cost determinations.

Accordingly, short-term reserves should be considered available for production costing purposes over the entire forecast period. Respondents should assign short-term reserves some type of penalty factor (as SCE did in its testimony) to properly reflect the expected limited dispatch of these units.[96] Given the above determination on age-deration, these short-term reserves should be included in ERI/reserve margin calculations only if the system's total MW capacity of standby units is greater than the required age-deration levels.[97]

For long-term reserves, we adopt IEP/IPC's recommendations. Standby units that require significant time and investment to place back into service should not be considered available for production costing purposes. Rather, they should first be tested for cost-effectiveness using the ICEM and, if found cost-effective, they should be considered available for production

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95 See D.88-11-052, mimeo. pp. 63-65 and D.89-12-015, mimeo. pp. 33-34.

96 See Exh. 12, p. IV-3.

97 This is apparently the case only for SCE.

costing purposes. As described in Section B. above, these same units should be excluded from ERI and reserve margin calculations, as age-derated capacity.

This raises the issue of whether to add back age-derated capacity for the purpose of calculating ERIs/reserve margins, when operation of a standby unit (either short- or long-term reserves) is found to be cost-effective. In its January 19, 1990 compliance filing, PG&E restored age-derated capacity from its short-term reserve units by testing those units for cost-effectiveness. Since these units require little or no investment to place in operation (or continue to operate), they all easily passed the cost-effectiveness tests.

PG&E's approach is inappropriate for the ER7 base case for two reasons. First, as CEC points out, ER7 adopted age-deration in order to force utilities to demonstrate, rather than assume, the continuing economic viability of their aging plants. Testing a unit in short-term reserves for cost-effectiveness does not accomplish this objective. It does not explicitly consider the costs of various life-extension options, as intended by ER7.

Second, in ER7 the CEC considered age-deration in conjunction with reserve margins. We agree with CEC that PG&E's approach is inappropriate without reconsidering the possible need for higher target reserve margins in the ER7 base case.[98] For the above reasons, currently operating units, or units in short-term reserves, should not be tested for cost-effectiveness for the purpose of restoring age-derated capacity in respondents' Phase 1B base case filings.

Refurbishment or repowering options, on the other hand, extend the useful life of a standby unit. It is therefore

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98 See CEC Comments on Utility ICEM Filings, February 5, 1990, pp. 5-7 and ER7 Appendix C, pp. C-21 to C-23.

consistent with ER7 to consider the cost-effectiveness of such options, and restore the age-derated capacity associated with returning units on standby reserve to service. We distinguish here between investments that merely enable the unit to be restarted for daily operations, and those that significantly overhaul the internal workings of the unit, thereby extending its useful life. For the purpose of restoring age-derated capacity (for ERI and reserve margin calculations), only the latter types of investments (e.g., repowering and refurbishments) qualify.

As SCE points out in its March 8, 1990 comments, units on short-term reserve may also be refurbished. As long as life-extension investments are involved, we believe it is appropriate to test the cost-effectiveness of a unit on standby reserve (either short- or long-term) for the purpose of restoring age-derated capacity. The only remaining issue is <u>how</u> to restore the age-derated capacity.

In addressing this issue, we first observe that the "pure" approach to applying the CEC's age-deration method would be to derate each unit in the utility's resource plan. Recognizing that this would be a cumbersome task, the CEC staff simplified the process by first counting all standby units towards the required age-deration levels. This was not intended to imply that 100% of the capacity of each standby unit would be unavailable. Rather, it was intended as a proxy for the sum of age-derated capacity, across all other plants, that should be excluded in evaluating the need for capacity.

Consistent with this intent, if refurbishment or repowering of a standby unit is found to be cost-effective after the requisite investments are made, <u>only the amount of age-deration associated with that plant</u> should be included as available capacity for reserve margin and ERI calculations. That amount should be calculated using the CEC's ER7 formula for age-deration.

The January 2 ALJ Ruling directed respondents to submit a list of all standby units, and indicate (1) the length of time it would take to restart the unit, and (2) what types of expenditures are required to restart the unit, and the approximate level of investment required. Respondents should also provide this information in their Phase 1B filings. Based on this information, respondents should indicate which units they consider short-term reserves, long-term reserves, and which will be tested for cost-effectiveness for the purpose of restoring age-derated capacity. For the Phase 1B base case scenario, respondents should rely on the ER7 findings, where applicable, in making this determination.[99] Respondents should also indicate which units were considered available for capacity valuation and production cost purposes in our most recent ECAC decisions.

D. Modelling Combined Cycle Units

Thermal power plants cannot be started instantaneously, and therefore need to be "committed" (i.e., synchronized to the system and running at minimum load) hours or days before the arrival of a peak load. Production cost models, like ELFIN, use commitment designations to tell the model how quickly a unit can be brought on line, and whether or not the unit must run at a minimum level.

In ELFIN, there are basically two ways to designate firm capacity for commitment purposes. The "minimum constrained" or "CM" designation indicates that the plant will have a unit minimum constraint; that is, once the plant is brought on line, it must continue to run for a specified period of time at its lowest level of output, irrespective of other economic considerations.[100] The

99 See ER7, pp. 5-12.

100 The remaining levels of output, or "blocks" for these constrained units are fully dispatchable, however.

"quick-start", or "CP" designation indicates that the plant has no unit constraint, is capable of a quick start, and is therefore fully dispatchable, at every level of output.

For the purposes of performing production-cost simulations with ELFIN, problems occur when attempting to model a unit that falls somewhere between the minimum constrained (CM) and quick-start (CP) designations. Combined cycle units represent the most notable example of this type of hybrid unit. Operators are able to shut these units down during the evening hours and restart them in the morning hours when demand begins to increase. Although these units are not unit-minimum constrained, neither do they exhibit the unqualified "quick-start" characteristics of a CT facility, for example.

The results of DRA's analysis indicates that the relative dispatchability of potential resource additions within the ELFIN model may substantially affect the results of the cost-effectiveness tests. In fact, DRA concludes that as much as 500 MW of <u>nondeferrable</u> CTs, and other peaking resources in SDG&E's resource plan might potentially be replaced by more cost-effective <u>deferrable</u> combined cycle plants, if these plants were modelled in a manner that more accurately reflects the true operating characteristics of these units.[101]

In its Phase 1A compliance filing (Exh. 12), SCE proposed a "hybrid" approach for modelling combined cycle units. This approach retains the "CM" ELFIN designation (in the ER7 data set), but lowers the minimum load points on the combined cycle units during the off-peak periods. The model then operates the units at this near-zero output during the off-peak hours, which simulates the unit's ability to shut down and resume operation in a single 24-hour period. During the course of the proceeding, other parties

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101 See Exh. 24, pp. IV-6 to IV-7 (as revised by Exh. 25B).

indicated their general support for SCE's approach.[102] We will adopt SCE's hybrid approach for Phase 1B.

At the workshop held on January 11, 1990, SCE provided a handout on a revised (preferred) method for modelling combined cycle plants.[103] Before the next update, SCE should conduct informal workshops among interested modellers (e.g., representatives from the CEC, DRA, SDG&E, PG&E, SF/U/F, and IEP/IPC) to develop a consensus approach for modelling units that can be cycled on a daily basis. Interested modellers should also use this forum to explore possible reasons for the counter-intuitive production cost results experienced by SDG&E, as described in its January 19 and February 2, 1990 filings in compliance with the January 2, 1990 ALJ Ruling. Depending on the outcome of the workshops, we may consider further modifying the adopted approach for future update proceedings.

In sum, for units that are capable of shutting down at night and returning to service the following day to meet peak loads, respondents should add minimum capacity states so these units can be cycled daily. This convention should apply to existing units as well as potential resource additions that can be cycled on a daily basis. As DRA points out, units other than combined cycle plants may exhibit this characteristic, and should be modelled accordingly. (DRA Brief, p. 30) For their Phase 1B compliance filings, respondents should submit a list of all units that they believe are capable of being cycled on a daily basis.

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102 See Exh. 22, pp. 3-4; Exh. 6, p. 2-3; DRA Brief, pp. 29-30; CEC Brief, pp. 27-29.

103 See ALJ Ruling On January 11, 1990 Workshop, dated January 16, 1990, p. 1.

E. Modelling As-Available QFs

During evidentiary hearings, it became apparent that the various modellers disagree on the best way to reflect the operation of as-available (e.g., S01) QFs in ELFIN. CEC, SF/U/F, and respondents all believe that as-available QFs should be modelled, in the aggregate, as providing firm, dependable capacity. IEP/IPC, on the other hand, argues that the S01 as-available contract is the epitome of a non-firm arrangement. Accordingly, IEP/IPC recommends that as-available QFs be modelled in a manner similar to economy energy. (Exh. 33 at 13; TR at 519.)[104] This approach tends to improve the cost-effectiveness of candidate resources.

IEP/IPC's position in this proceeding is inconsistent with our long-standing position that as-available QFs supply dependable aggregate capacity.[105] Moreover, it is inconsistent with our modelling determinations in ECAC proceedings. In those proceedings, as-available QFs are generally modelled as CM units at their effective capacity. In other words, we treat as-available QFs in the aggregate as firm, dependable capacity, but derate specific units to take account of the fact that they may not all be operating simultaneously or at 100% nameplate capacity.

CEC and SF/U/F apparently disagree over which ELFIN commitment designation to use for as-available units, and also over how much to derate units. However, these differences do not appear to significantly affect the ICEM results. Therefore, for this BRPU update, we will adopt the CEC's modelling conventions. For future

104 In ELFIN, the non-firm commitment designation is "CN", which assumes that the unit cannot be relied upon to meet commitment targets.

105 See D.82-01-103, mimeo. p. 149, FOF 34, 37, 40; D.87-05-060, mimeo, pp. 38-39. We note that IEP/IPC's position on this modelling issue is also inconsistent with arguments it has made in the past regarding the dependability of as-available QFs.

updates, we expect respondents to model as-available QFs in the manner adopted in their most recent ECAC proceeding.

F. Variable O&M

In running the ELFIN production cost model, PG&E, SCE, SDG&E, and DRA all excluded the variable O&M costs associated with existing generation units, consistent with the ER7 data set. All parties agree, however, that variable O&M should be accounted for in evaluating the cost-effectiveness of new resource additions. IEP/IPC attempted to do this by adding variable O&M to the ER7 data set. But when variable O&M is included in the ELFIN data set, the current version of the model will make dispatch decisions based on variable costs that include O&M. According to PG&E, this is contrary to actual utility operations.

To address this problem, PG&E initially recommended a post-processing technique to account for variable O&M. (Exh. 6, p. 3.) The essence of the approach is to calculate variable O&M costs by multiplying the kWh (determined from the ELFIN run) by the appropriate unit price, in cents/kWh. This approach requires a separate calculation for each resource in the utility's resource plan. This can be accomplished in a spreadsheet.

In its brief, PG&E proposed an alternative approach which, in PG&E's view, would preserve most of the accuracy of post-processing while being much less burdensome. This approach would increase the total fuel cost of the candidate resource (but leave the dispatch price unchanged) to approximate the difference in variable O&M costs. To implement this approach, the utility would develop an average O&M rate for existing units, and subtract that rate from the total fuel costs associated with the candidate resource addition.

While PG&E's alternative approach has the advantage of being less burdensome than post-processing, we believe that it has significant disadvantages. The most obvious one is the loss in accuracy when plants with a wide range of variable O&M costs are averaged. In addition, there is no specificity to PG&E's proposal on how to derive the average O&M rate. We prefer a post-processing method that clearly presents all assumptions used for variable O&M costs. We are also confident that the ELFIN modellers in this proceeding can develop electronic spreadsheets to minimize the calculation time.

Therefore, for the Phase 1B filings, parties using ELFIN Version 1.7 should post-process variable O&M costs, along the lines originally proposed by PG&E. Since the ER7 data set did not include variable O&M for existing resources, we direct respondents to use the estimates of variable O&M costs they filed in the CEC's CFM-7 proceeding, as the base case values, consistent with our determinations in D.89-09-093 on PG&E's avoided O&M costs.[106] Alternative estimates may be considered for the Phase 1B sensitivities (See Section VIII. below).[107]

G. Other Modelling Changes

Respondents also recommended that a number of relatively minor adjustments be made to the CEC staff ELFIN modelling conventions. These changes are summarized in Table 4. No party challenged these changes as being incorrect or unreasonable, although the CEC had some slightly different recommendations on some modelling conventions. All parties agree, however, that these changes are unlikely to change the ICEM results (TR at 526-528).

We will adopt the changes outlined in Table 4 as reasonable for this update cycle, with one exception.[108] PG&E

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106 See D.89-09-093 (in A.88-12-005 and I.89-03-033), FOF 7.

107 If any party uses a model (or a version of ELFIN) that does not pose the problem described above, then they obviously do not have to conduct any post-processing. However, for their Phase 1B base case analysis, they should use the CFM-7 values for variable O&M presented in the respondents' filings.

108 Today's endorsement of these modelling changes does not preclude parties from raising them for further debate, in future BRPU cycles, or other Commission proceedings.

proposed changing the ELFIN "COMMT" feature to "NCOMMT". The NCOMMT feature commits sufficient generation at its rated capacity to meet load plus spinning reserve requirements, instead of committing de-rated (i.e., expected capacity after outages) generation capacity. We are aware that there is still some debate in our ECAC proceedings over how to correctly model commitment in ELFIN. However, we have no record in this proceeding upon which to make this type of determination. Moreover, none of the other parties indicated any need to make this generic change to ELFIN's internal commitment logic. For this update, PG&E should retain the COMMT feature in ELFIN.

V. Application Of ICEM

In D.86-07-004, we adopted DRA's two-part test of cost-effectiveness, consisting of a first-year and life-cycle test, for our ICEM analysis of potential resource additions.[109] The first-year test is developed by comparing the first-year cost of a resource addition with changes in production costs and shortage values (i.e., resource benefits) in a given year. In other words, one compares production costs and shortage values with and without a given resource in the resource plan. The life-cycle test is

109 In D.86-07-004, we did not specifically describe the ICEM tests of cost-effectiveness. Rather, we referred to DRA's testimony in A.82-04-44 et al. (Exh. 201) for a description of these testing procedures. DRA's Exh. 201 was therefore introduced into evidence in this proceeding, as Reference Exh. A. (See D.86-07-004, mimeo. p. 83 and FOF 238.)

similar, except this test compares benefits and costs over the life of the resource.[110]

During evidentiary hearings, it became apparent that parties implemented the ICEM two-part testing procedure in significantly different ways. These differences relate to the composition of the tests, as well as the optimization sequence used to apply them. On December 1, 1989 ALJ Gottstein directed parties to hold a workshop to identify all of the differences in their respective approaches to implementing the ICEM. The objective of the workshop was to narrow the range of differences and, if possible, agree upon an approach for Phase 1B.

The ICEM workshop was held on December 5, 1989, and a workshop report was filed on January 2, 1990 (late-filed Exh. 51). This report contains an excellent description of the ICEM implementation issues, parties' positions, and areas of remaining disagreement. Although agreement was not reached, the parties did a commendable job of developing concise, clear explanations of their preferred approaches and methodological differences. We address below the major outstanding issues.

A. ICEM Optimization Sequence

The question of whether to test resources in a sequential manner, or non-sequentially, was the subject of considerable debate

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110 More specifically, cost-effectiveness is determined by evaluating the changes, from one iteration to the next, in (1) fixed capital costs (including fixed O&M), (2) production costs, and (3) shortage values. If the change in (1) is less than the change in (2) plus (3) over the resource life, then adding this resource will reduce total costs on a life-cycle basis. The first-year test is similar, but only looks at the first-year (levelized, ramped by inflation) fixed capital costs of the resource. The resource is added only when (and if) the first-year costs associated with the resource are less than changes in (2) plus (3) for a single year of the planning horizon. Table 5 illustrates these calculations.

in this proceeding. DRA, SCE, SF/U/F, and IEP/IPC would apply the ICEM in a time-sequential, or chronological manner.[111]

Under the time-sequential approach, the first-year test is used to determine the optimal year for adding a cost-effective resource. Starting with the initial year of the planning horizon, those options passing the first-year test in the initial year of the planning horizon are tested for life-cycle cost-effectiveness and, if cost-effective, added to the resource plan. If it is cost-effective to add more than one resource in a given year, comparisons of life-cycle costs are used as tie-breakers. The evaluation proceeds to subsequent years of the planning horizon, after sufficient cost-effective resource additions (including consideration of shortage resources, i.e., gas turbines) have been added to meet reserve margins. Figure 2 illustrates this approach.

SDG&E, on the other hand, contends that resources should be added to the resource plan in a non-sequential manner, based on a two-part decision rule. First, for a given iteration, SDG&E would determine which resource is most cost-effective based on life-cycle costs and benefits. Second, that resource which is found most cost-effective over its life is then added to the resource plan in the first year in which it passes the first-year test. The evaluation then proceeds to the next cost-effective resource until sufficient cost-effective additions (including

111 PG&E originally applied the time-sequential approach, but apparently modified its position during the workshops. At the workshop, and in its brief, PG&E proposes a compromise approach in which the time-sequential approach would be used to develop a preliminary resource plan. This approach would allow the utility to modify this preliminary plan using any methodology, provided the utility stayed within the confines of the first-year test, the life-cycle test and minimum reserve requirements. (Exh. 51, p. 12; PG&E Brief, pp. 24-26.)

consideration of shortage resources) have been added to meet reserve margins in all years of the planning horizon.[112]

The record in this proceeding indicates that the non-sequential approach has several major disadvantages. As DRA points out, the non-sequential approach relies on a decision rule that would add resources as much as 30 years into the future. Indeed, in implementing its ICEM, SDG&E incorporated currently unavailable technologies in its resource plan, based on its own assessment of when these technologies might become commercially viable. We agree with DRA that this methodology poses the risk of over-committing to technologies for which ultimate development is uncertain.

The non-sequential approach is also much more burdensome to implement than the time-sequential approach, since its decision rules require a life-cycle cost analysis of each resource option, even ones that may not pass the first-year test during the planning horizon. Moreover, as described in Exh. 51, the non-sequential approach is more likely to result in a resource plan with either too little or too much capacity in certain years. This can occur when there are capacity shortages early in the planning horizon, with adequate capacity in the later years.

For example, assume a coal plant was found to pass the first-year test in 1996, and completely filled the utility's capacity requirements in every year thereafter. Assume further that the utility's existing and committed resources were sufficient to meet reserve requirements through 1993. This raises the

112 Regardless of the optimization sequence used, the ICEM approach calls for examining one <u>single resource at a time</u> for cost-effectiveness, in a given iteration. This approach was not followed by all parties in presenting their Phase 1A results, but should be for the Phase 1B filings and future ICEM applications.

question of what resource additions to add for 1994 and 1995--the so-called "doughnut effect". (Exh. 51, pp. 9-10.)

If short-term options are not available, the utility must either add shortage resources to fill the capacity shortage, or make some other adjustments to the resource plan. Adding shortage resources (i.e., gas turbines) would result in overcapacity in the latter years, when the resource plan is filled up with future cost-effective additions (e.g., the coal plant). The alternative, which SDG&E used in its compliance filing, is to advance the in-service date of the cost-effective resources to the year of capacity need. This adjustment requires relaxing the first-year test for those resources. (Exh. 22, pp. 16-19)

In SDG&E's view, the non-sequential approach is a more optimal least-cost planning tool because, unlike the time-sequential approach, it enables the planner to explicitly consider attractive resource options that are available later in the planning horizon. We agree that this is a potential advantage of the SDG&E's preferred approach. However, this advantage does not, in our view, outweigh the disadvantages outlined above.[113] Moreover, there is no evidence to suggest that the time-sequential approach compromises to any significant extent the accuracy of results.

113 SDG&E also argues that the DRA, in developing the ICEM procedures approved by this Commission, specifically endorsed the non-sequential approach (SDG&E Brief, p. 14, Appendix A). We note that, while DRA apparently endorsed this approach in theory, in actual implementation, they used the time-sequential approach for their computer analysis of resource needs. (See Reference Exh. A, pp. 101-122, compared with pp. C-6 to C-7.) Moreover, the excerpts referenced in Appendix A of SDG&E's brief represent cross-examination of DRA's rebuttal testimony (Exh. 412 in A.82-04-44 et al.) in the compliance phase of A.82-04-44 et al. We did not specifically address the recommendations presented in that testimony in any of our compliance decisions.

As we described in D.85-07-022, in selecting an LRAC methodology we are guided by various criteria, including accuracy in determining the utility's LRACs and comprehension, understanding of the methodology and practicality of implementation. While accuracy in the cost determination is obviously the foremost consideration, understanding of the methodology and practicality in its implementation should not be sacrificed.[114]

Using these standards, we have concluded that the best sequence for applying the ICEM tests of cost-effectiveness is the time-sequential approach. This approach is straightforward and relatively simple to implement. Application of the cost-effectiveness tests under this approach involves a consistent, verifiable set of decision rules. As described above, the time-sequential approach is also less prone to resource planning anomalies whose solution requires increased effort and complexity. For these reasons, we adopt the time-sequential approach for implementing the ICEM tests of cost-effectiveness.

B. <u>Screening of Potential Resource Additions</u>

Under the ICEM approach, resource planners may initially screen potential resource additions, in order to determine which resource options are the least expensive in each operating mode (baseload, intermediate, and peaking). Only the cheapest resources, by operating mode, are subjected to the more elaborate ICEM tests of cost-effectiveness. (Reference Exh. A, pp. C-8 to C-11.)

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114 See D.85-07-022, mimeo. p. 48. We chose DRA's simplified GRP methodology for calculating a utility's LRACs because the more direct approach would have involved multiple layers of data, computer modelling, and calculations that would be difficult to implement and verify.

PG&E, SCE, SDG&E, and DRA conducted some form of cost-based screening to reduce the number of resource options included in the ICEM analysis. SCE used a cost per kW screening table. PG&E used cost per kW screening curves to test each resource option from 0% to 100% capacity factor. DRA used cost per kWh screening curves. SDG&E screened resources using benefit cost ratios, based on an assumed capacity factor, along with several qualitative criteria. (Exh. 18, Appendix, Table 3.)

SDG&E proposes that we allow utility discretion in selecting and implementing a prescreening approach. We disagree. Prescreening can substantially reduce, or change the nature of, the types of resources considered potentially deferrable by QFs. This is evidenced by the fact that, out of a total of 52 resource options, SDG&E's prescreening eliminated approximately one-half of those from further analysis. (Exh. 51. Table 3a.) We prefer to adopt a consistent method for use by all parties. In this way, we can avoid future debates over whether or not resources that were screened out should have, in fact, been subjected to the ICEM analysis.

Of the various screening techniques used in this proceeding, we find that PG&E's method best captures the intent of the methodology, namely, to screen out the most expensive options for each operating mode. PG&E compares the levelized cost of power for resource options over a 30-year period. Any resource option that provides the lowest cost of power at some capacity factor is subjected to the ICEM tests of cost-effectiveness. (Exh. 2, pp. 19-20, T-1.)

This approach should be used in Phase 1B and future update proceedings by any party choosing to screen resource options prior to commencing the ICEM analysis. If a party chooses to conduct a preliminary screening, it must screen all resources in the same manner, using only the levelized cost criteria described above. However, the results of the screening analysis may be relaxed if a party believes that one or more resources that did not pass the screening should still be subjected to the ICEM analysis.

C. <u>The First-Year Test</u>

Parties to this proceeding expressed divergent views on several aspects of the first-year test:

(1) Whether or not a first-year test can be constructed for all resource options;

(2) Whether the first-year test should be relaxed for resources that are not freely scheduable, or for DSM programs;

(3) Over what planning horizon should the test be implemented; and

(4) How to take construction lead-times into account.

These issues are discussed below.

1. <u>Composition of the First-Year Test</u>

The first-year test requires that a ramped fixed cost stream be constructed for options included in the ICEM. In its compliance filing, SDG&E argued that the ramped stream required that the option be infinitely replicable at some nominal inflation rate. (Exh. 18, p. 5; Exh. 22, p. 14.) Therefore, SDG&E did not construct a ramped stream for options, such as power purchase agreements, that it believed were not replicable in this manner.

Other parties do not see "infinite replicability" as an impediment to the construction of a ramped fixed cost stream for all resource options. They assert that the calculation of the ramped fixed cost stream only requires knowledge of fixed revenue requirements for the life of each option, not for an infinite repetition of the option (i.e., the single lifetime approach).[115] Subsequent to the ICEM workshop, SDG&E calculated the ramped fixed cost streams using the infinite repetition approach and the single lifetime approach, and concluded that the two approaches yield identical results (Exh. 51, p. 2).

Based on the above, we conclude that a ramped fixed cost stream can, and should be constructed for all resource options. We also agree with SF/U/F and other parties that only real escalation should be contained in the fixed cost stream.

2. Treatment of Resources Not Freely Scheduable/DSM Programs

SDG&E contends that it is impractical to base the timing of resource options on the first-year test when the in-service date of the resource is relatively inflexible. (Exh. 22, p. 12.) In particular, SDG&E notes that it would be possible for a power purchase offer to be the most cost-effective addition, even though the first-year test would indicate that it should not be initiated until the second year of the contract. In these instances, SDG&E recommends that the life-cycle test be given preference over the first-year test. (SDG&E Brief, pp. 6-7.) At the ICEM workshop, SCE and PG&E supported SDG&E's position. (Exh. 51, p. 3.)

SF/U/F and IEP/IPC, on the other hand, take the position that a purchased power offer should pass the first-year test in the same manner as any other resource. Otherwise, they argue, the whole ICEM process would be called into question. SF/U/F and IEP/IPC would therefore exclude purchased power offers from the resource plan if the terms could not be structured in such a way

115 This calculation consists of computing the real fixed charge rate (or economic carrying costs) associated with plant additions in each year that a plant could potentially come on line. It is calculated as the product of installed costs times an economic carrying charge rate.

that the contract would pass the first-year test in the year the purchase was to begin. Similarly, DRA argues that the utility can negotiate the starting date of the contract to ensure that it passes the first-year test.

We concur. Relieving power purchases from the requirements of the first-year test puts that type of resource at an advantage not enjoyed by any other supply option. SF/U/F, IEP/IPC, and DRA present compelling arguments for subjecting power purchase options to the same tests of cost-effectiveness as any other potential resource addition.[116]

At the same time, however, DRA requests that we make an exception for DSM. (Exh. 51, p. 4, DRA Brief, pp. 24-25.) We will not make a final determination regarding the treatment of DSM until we address the broader integration issues scheduled for Phase 3. In the meantime, however, for SDG&E's Phase 1B ICEM analysis of DSM programs, we expect SDG&E to subject DSM programs to the same ICEM tests of cost-effectiveness as supply-side resources. This should give us an indication of how DSM programs fare when subjected to the first-year test. This approach is also consistent with the stipulation that was reached between DRA and SDG&E (and approved in D.88-12-085) in SDG&E's 1989 test year GRC.[117] For application of the first year test, SDG&E should ramp the fixed costs of DSM programs.

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116 We also note that SDG&E did not encounter any situation where it had to reject an unscheduable resource, based on the first-year test, when it reran its ICEM analysis. See <u>Filing of San Diego & Electric Company in Compliance With Administrative Law Judge's Ruling Dated January 2, 1990</u>, January 19, 1990, pp. 4-5.

117 DRA and SDG&E agreed that, in this BRPU cycle, SDG&E would subject a variety of DSM programs to the ICEM tests of cost-effectiveness, along with all other supply-side options. See <u>Joint Exhibit on Resource Plan</u> (Exh. 43), filed by DRA and SDG&E in A.87-12-003.

3. Planning Horizon

Parties also did not agree on the appropriate planning horizon for applying the first-year test. SDG&E, for example, used a 17-year planning horizon (i.e., 1990 to 2007) whereas other parties used 8-12 years. DRA recommends that a specific planning horizon be established, for this and subsequent updates, irrespective of whether the time-sequential or non-sequential approach is adopted.

We agree. The 12-year planning horizon we adopted in D.86-05-024 is a logical choice.[118] For the Phase 1B filings, potential resource additions should be included in the resource plan only if they pass the first-year test during the 1990-2001 period.

4. Construction Lead-Times

In applying the first-year tests, some parties apparently considered construction lead-times as an impediment, or constraint, to applying the first-year test.[119] In other words, if a utility-built resource required a six-year construction lead-time, but passes the first year test in year 3, it would not be added to the resource plan until the later year.

In D.86-05-024, we made a determination on this issue:

> "QFs generally have shorter lead-times than utility projects, so the resource plan scenarios to be filed in the compliance phase of this proceeding should show any cost-effective resource as added in the first year that it becomes cost-effective regardless of whether the utility itself could have built the

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118 See D.86-05-024, mimeo. FOF 16.

119 This issue was not raised at the ICEM workshops. However, in her January 2, 1990 Ruling, ALJ Gottstein directed parties to treat construction lead-times in a manner consistent with our prior orders. We reiterate this directive today.

resource in that length of time."
(D.86-05-024, mimeo. FOF 17.)

As we noted in D.86-05-024, this departure from traditional utility planning is appropriate because "QFs may defer or avoid a resource even before the utility could have built the resource." (id., p. 25.) Accordingly, the utility should add any utility-built resource in the first year that the resource becomes cost-effective, regardless of construction lead-time.

D. The Life-Cycle Test

As discussed in Section A. above, the life-cycle test will be used to compare relative cost-effectiveness of resource options when more than one resource passes the first-year test.[120] During this proceeding, parties presented several alternative measures of life-cycle cost-effectiveness, including benefit-cost (B/C) ratios, net present value (NPV) dollar savings, and levelized cost per kW comparisons. These various measures were discussed and compared in detail during the ICEM workshops. (See Exh. 51, pp. 5-7.)

Based on these discussions, parties reached general agreement that B/C ratios are a reasonable means of breaking ties between resource options with dissimilar characteristics. However, SCE prefers to use levelized costs per kW. We agree with SDG&E that SCE's preferred approach does not adequately compare low capital cost peaking options with options having higher capital costs, but substantial offsetting energy benefits.[121] The B/C ratio, on the other hand, reflects these differences, while at the same time comparing for size and lifetime differences. For these

120 This test will also be used to determine whether or not a resource that passes the first-year test is, indeed, cost-effective over its lifetime.

121 SDG&E Brief, pp. 12-13; Exh. 51, pp. 6-7.

reasons, we adopt the B/C ratio as the ICEM measure of relative life-cycle cost-effectiveness.

More specifically, a resource is considered cost-effective over its lifetime if the NPV of the change in total costs (i.e., fixed costs of the option, plus changes in production and shortage costs) is positive over the resource life. Relative cost-effectiveness should be determined using B/C ratios, computed by dividing the NPV of life-cycle benefits by the NPV of life-cycle costs of the option. More specifically, the numerator is comprised of the change in shortage costs plus the change in production costs (with and without the IDR) minus the production costs of the IDR, all expressed in NPV. The denominator is comprised of the total fixed costs and production costs of the IDR, in NPV. This is consistent with the B/C ratios defined for DSM (Total Resource Cost test), where total benefits are divided by total resource costs.[122]

We also concur with SDG&E and others that a life-cycle test of cost-effectiveness, by definition, requires some form of extrapolation of benefits and costs beyond the ER7 20-year planning horizon. Several extrapolation methods were discussed at the ICEM workshops. (Exh. 51, pp. 7-8.) Some parties supported extension of the ER7 data sets, which would require extrapolation of demand forecasts, DSM impacts, and other resource planning assumptions. We agree with SDG&E and SCE that this effort would be extremely speculative, as well as unduly arduous.

At the ICEM workshop, SDG&E proposed a middle ground between DRA's position of truncating the life-cycle test and the

122 See Standard Practice Manual, Economic Analysis of Demand-Side Management Programs, December 1987, Appendix C.

alternative of extending the data sets.[123] SDG&E suggests using the existing ELFIN data sets through 2007 and then extrapolating production cost savings through each option's lifetime using general inflation. PG&E also expressed support for this approach in its brief. (PG&E Brief, p. 28.) We endorse SDG&E's proposal.

SDG&E also recommends that, in computing B/C ratios, the fixed cost of each option be adjusted to account for differences in reliability among resource options (Exh. 18, pp. 14-15). We will not adopt this adjustment. The procedures described in SDG&E's testimony would add time-consuming calculations to a process that already requires a significant amount of model and spreadsheet analysis. Moreover, there is no evidence in this proceeding to suggest that pure B/C ratios are inadequate for the purpose of comparing relative cost-effectiveness.

E. <u>Treatment of Non-Commercial Technologies</u>

In its ICEM analysis, SDG&E evaluated two technologies that are not currently commercially available: Steam injected gas turbines (STIGs) and intercooled steam injected gas turbines (ISTIGs). DRA recommends that only currently commercially available technologies be considered. DRA argues that these conditions will minimize the risk of over-committing to technologies for which ultimate development is uncertain and for which benefits are dependent upon long-term, relatively less certain, production cost savings.

We agree only in part with DRA's position. There may be currently non-commercial technologies, or demonstration projects, that are close to the point of commercial operation. To categorically ignore the potential of these resources in the resource planning process would, in our view, disadvantage

123 DRA counted production cost benefits only through the year 2002. No extrapolation was included in the life-cycle analysis.

ratepayers. Therefore, we will not preclude consideration of a non-commercial technology if there is good reason to expect it to become commercially available sometime during the 12-year planning horizon. However, the burden will be on the utility to show that the technology is likely to be commercially available during that period. Moreover, parties may consider the uncertainties associated with expected costs and operating characteristics of such resources in Phase 1B.

VI. Other ICEM Implementation Issues

As described in Section II.F., the following two ICEM implementation issues were deferred to this update:

(1) What method(s) to adopt for connecting short-run and long-run demand forecasts, and

(2) How to apply the new gas rate design in testing the cost-effectiveness of potential new resources.

In addition, SF/U/F raised the issue of whether or not resource additions that cost less than a CT are deferrable by FS04 QFs. Finally, several parties asked us to confirm that the proper implementation of ICEM will show CTs to be cost-effective in any year when the ERI is greater than 1.

We address each of these issues in the sections that follow.

A. Connecting Short-run and Long-run Demand Forecasts

In D.88-09-026, we recognized that there will always be a gap between the current short-range demand forecast that we adopt for each utility and the CEC's long-range demand forecast (which begins in year 5).[124] Recognizing the need to allow some flexibility in connecting these forecasts, we gave each utility the option of choosing between three alternative approaches: (1) trending from the short-range forecast to the CEC's year 5; (2) repetition of the CPUC short-range forecast for the connecting years; or (3) repetition of the CEC's year 5 forecast for the connecting years. For this update, we directed respondents to explicitly choose among one of these approaches, and indicate whether the choice has a material impact on its conclusions regarding avoidable resources.

The first year of the ER7 adopted demand forecast is 1992. ER7 also presents illustrative loads for each utility, for the years 1989 to 1991. PG&E, SCE, and SDG&E all used these illustrative loads for the beginning of the forecast period. However, for future BRPU proceedings, PG&E and SDG&E recommend that the trending approach be used.[125] In their view, trending minimizes any discontinuities between adopted long- and short-range forecasts, and provides a more plausible demand projectory for the first five years of the planning period.[126]

PG&E and SDG&E did not use the trending approach in this proceeding for different reasons. PG&E claims that the difference between the trending approach and using CEC's illustrative loads is

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124 See D.88-09-026, mimeo. pp. 18-19. Our short-range demand forecasts are adopted typically in GRC or ECAC proceedings.

125 SCE did not make any recommendation as to the appropriateness or its preference regarding any of the options listed in D.88-09-026.

126 PG&E also illustrated that the difference between the trending approach and using CEC's short-range forecast was insignificant. See Exh. 2, Table III-1. In its prepared testimony (Exh. 46), SF/U/F criticized PG&E's comparisons in this table, claiming that PG&E did not adjust the CEC forecasts to make them consistent with forecasts used in ECAC proceedings.

insignificant. PG&E presents a comparison of the two approaches in Exh. 2, Table II-1. SDG&E did not use the trending approach because the Commission did not explicitly adopt a short-run peak demand forecast in its recent ECAC.

With regard to PG&E's claim, SF/U/F illustrates in Exh. 46 that PG&E did not adjust the CEC short-range demand forecast to make it consistent with forecasts used in ECAC proceedings. Had PG&E done so, SF/U/F asserts that the comparison would show significant differences. Specifically, once put on a consistent basis, SF/U/F shows that the CEC's illustrative peak demand forecast for 1990 is 323 MW <u>below</u> the peak demand forecast resulting from trending.[127] This results in a downward trend between the most recently used ECAC forecast and the first year of the CEC adopted forecast. On the energy side, the CEC forecast does not exceed the 1990 ECAC forecast until 1994.

SF/U/F's analysis highlights the importance of linking forecasts on a comparable basis. For example, as SF/U/F witness Branchcomb points out, the ECAC forecasts are forecasts of actual sales, while the CEC forecast is one of total consumption. To put these two forecasts on a comparable basis, one must adjust the ECAC forecasts to account for conservation, load management, and self-generation (TR at 908).

For the Phase 1B base case analysis, respondents should continue to use the CEC's illustrative loads for 1989-1991. However, in their Phase 1B filings, each respondent should explicitly compare this approach with trending, making adjustments along the lines described in SF/U/F's testimony. As SDG&E points out, we did not adopt a short-range peak load forecast in our

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127 Upon cross-examination by DRA, SF/U/F points out some additional consistency adjustments that would make this MW difference even larger. See TR at 907-911.

recent ECACs. However, PG&E estimated the ECAC peak load by using an average load factor from the ER7 forecast for years 5-12 (Exh. 2, Table III-1). This approach seems reasonable, and should be used by SCE and SDG&E in making the comparisons described above.

B. Application of New Gas Rate Design For ICEM Testing

The issue of the appropriate Utility Electric Generation (UEG) gas rate to be used as a basis for QF payments has been raised in a number of proceedings before this Commission since 1985. The issue has grown more complex with the inception of unbundled gas rates, as promulgated in OII 86-06-005. In D.88-07-024, we found that QFs receiving short-run energy payments should have their payments calculated based on the full average UEG rate less the customer charge. However, we deferred making a decision on the appropriate gas cost to use in determining the cost-effectiveness of potential new resources. We address that issue now.

All parties to this proceeding recommend including only the commodity costs of gas for production cost model dispatch decisions. For determining the cost-effectiveness of resource additions, however, parties recommend using the full average cost of gas, including transportation-related gas costs.

We agree. As PG&E points out, utility system operators do not consider transportation-related gas costs (e.g., transmission, distribution, administrative and general, and other non-gas costs) in selecting which units to dispatch. We also agree with PG&E that a long-term resource addition is likely to avoid, not only the commodity costs of gas, but also the long-run marginal costs of the gas distribution system.[128] The ER7 data set (which uses the full average cost of gas as the dispatch price) should be modified accordingly. For the Phase 1B base case, SCE, SDG&E, and PG&E should use the dispatch gas costs they developed for their Phase 1A compliance filings.

C. Deferrability of Resources With No ERCCs

A utility adds a new resource for reliability benefits (i.e., to reduce shortage costs) and to improve its operating efficiency (i.e., reduce marginal operating costs). The term "energy-related capital costs" designates that portion of a resource option's fixed costs that a utility incurs because of anticipated benefits to its operating efficiency. ERCCs are calculated by taking the difference between the fixed costs of that option and those of the utility's marginal capacity investment (or shortage resource), a CT.

In Exh. 46, SF/U/F points out that a number of the resource options passing the ICEM tests of cost-effectiveness have capital costs that are less than those of a CT. SF/U/F asserts that these resources are nondeferrable because they lack, like CTs, any ERCCs. SF/U/F cites D.87-11-024 as the basis for this assertion. Rather than issuing an FSO4 based on an option that costs less than a CT, SF/U/F believes that the utility should pursue that option itself. PG&E, SCE, and SDG&E concur.

DRA, on the other hand, does not agree with SF/U/F's interpretation of D.87-11-024. DRA argues that the language of that decision does not indicate that baseload or intermediate load

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128 We recognize that transportation-related gas costs are currently developed from embedded, and not marginal costs. However, until we have developed long-run marginal gas costs, these embedded cost estimates are our only proxy for the incremental system costs that are deferrable by non-gas fired (or very gas efficient) resource additions.

plants without ERCCs should be considered nondeferrable. Moreover, DRA argues that, in D.87-11-024, our decision to exclude peakers as the basis for FS04 prices was based on a consideration of several factors, not just the lack of ERCCs.

We have carefully reviewed our determinations in D.86-07-004 and D.87-11-024.[129] As DRA points out, we did not explicitly state that any cost-effective resource which lacks ERCCs is nondeferrable for the purpose of FS04. Nevertheless, that was our intent. In both orders, we clearly stated that it was the absence of ERCCs that dictated our decision not to authorize a peaker-based long-run standard offer. Moreover, in D.86-07-004 we stated that a peaker essentially does not have such costs.

As we explained in D.87-11-024, a resource that does not have any ERCCs will only be added to the resource plan if there are no cost-effective baseload or intermediate resource options to meet short-term reliability needs and reduce marginal operating costs. In other words, this type of resource will only be found cost-effective if it is needed for capacity as a shortage (i.e., peaking) resource for reliability purposes.

In their February 5, 1990 comments, IEP/IPC claims that a combined cycle unit could replace return-to-service options at significant energy savings.[130] However, our adopted ICEM tests of cost-effectiveness will identify these situations, if they exist. Using B/C ratios as tie-breakers in the ICEM analysis will indicate if a resource with no ERCCs is needed as a shortage resource, or if there are baseload or intermediate load resources that should be added instead for both reliability and energy saving purposes. Accordingly, in conducting their ICEM analyses, we expect

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129 See D.86-07-004, mimeo, p. 82; D.87-11-024, mimeo. pp. 22-23.

130 See Comments of IPC on Revised Utility ICEM Analyses, February 5, 1990, p. 2.

respondents to test the cost-effectiveness of baseload and intermediate load resources, in addition to resources with no ERCCs, for each year of the planning horizon.

In sum, a resource with no ERCCs which passes the ICEM tests of cost-effectiveness is, by definition, a "peaker", as we have used the term in D.86-07-004 and D.87-11-024, and should not form the basis of FSO4. Given our current use of a CT as the utility's marginal shortage resource, any resource with fixed costs (including fixed O&M) that are lower than those of a CT will, by definition, have no ERCCs.[131] Accordingly, if these resources are found to be the most cost-effective addition to a utility's resource plan, they should not form the basis of an FSO4 offer.

D. Cost-Effectiveness of CTs When ERI Equals 1 or Greater

As discussed above, the CT is assumed to be the utility's marginal capacity investment, or shortage resource, when capacity is needed. We measure the need for capacity on the utility system, at any point in time, by comparing the levels of reserve margins or expected unserved energy (EUE), to prespecified targets.[132] From this comparison, we develop an index of reliability, or ERI. The ERI multiplied by the value of a CT yields the shortage value of

131 In fact, the ERCCs for these resources will be negative, which means that they provide reliability benefits at a cost that is even lower than the utility's normally least-cost shortage option. We agree with SCE and SF/U/F that, given our current valuation of capacity, the utility should always build a shortage resource, when needed, that is less expensive than a CT.

132 For SDG&E and SCE, we express the reliability target as EUE, derived by analysis of the utility system in one historical year. For PG&E, we use CEC-based target reserve margins. See D.86-11-071 and D.88-03-079 in A.82-04-44 et al.

new capacity. Hence, by definition, a CT will be cost-effective in any year in which the ERI is 1.0 or greater.[133]

In some of the model runs presented in this proceeding, CTs apparently did not pass the ICEM first-year test when the ERI was 1.0. We agree with SF/U/F and others that this is most probably a model or modelling anomaly:[134]

> "Since the capacity need which the ERI of 1.0 indicates may be met with the addition of a combustion turbine which is never dispatched, these [operation and maintenance] costs should not affect the decision to shore up a deficient capacity situation. If the modeling is indicating such variable costs when the unit is not dispatched, or is dispatching the unit with resultant increases in system costs, then there is an obvious problem in the modeling, or the model, or the unit was actually needed to satisfy load or spinning reserve requirements." (SF/U/F Brief, pp. 2-3.)

For their Phase 1B filings, respondents should indicate whether or not this anomaly occurs, and attempt to explain what has caused it. Hopefully, in this way, the model or modelling problems can be corrected over time. In any event, for purposes of the ICEM analysis, a CT should be considered cost-effective in any year in which the ERI is 1.0 or greater.

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133 The utility may, however, find that another resource is more cost-effective, based on the ICEM tests, because it results in fuel savings as well as meets reliability targets. Nonetheless, the CT should always pass the first-year test in any year when the ERI is one or greater, even if it is not the resource added in that year.

134 We suspect that this type of anomaly may result from ELFIN's commitment logic, which cannot "recommit" units (once uncommitted), even if a system dispatcher would to minimize operating costs.

VII. Base Case Assumptions For Candidate Resource Additions

Respondents, CEC, DRA, and IEP/IPC all presented cost estimates for various candidate resource additions in this proceeding. These include both site-specific and generic estimates. As described in late-filed Exh. 50, there were major differences among parties with regard to (1) the types and sizes of resources considered, (2) the types of costs included in the estimates, and (3) financial data.[135]

A. Types and Costs of Candidate Resources

As described in Exh. 50, each party conducting the ICEM analysis examined a different range of candidate resources. SDG&E screened over 50 options, including CTs, repower and life-extensions, unit upgrades, coal, purchase power, STIGs/ISTIGs, and combined cycle units. PG&E screened CTs, combined cycle units, enhanced oil recovery, in-state direct fired coal, compressed air energy storage, and options to continue existing unit operations. SCE screened most of the same options as PG&E, but also looked at geothermal and repower options. IEP/IPC looked at three generic options (i.e., CT, combined cycle, and coal-steam) for all three utilities.[136]

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135 See Comparison Exhibit On Resource Costs and Financial Data (Exh. 50). This exhibit was developed during evidentiary hearings at the request of ALJ Gottstein. It contains, in a consistent format, all of the parties' assumptions for developing cost estimates of candidate resources, including financial data. For future updates, we expect all parties presenting cost and financial assumptions to use the format developed for this exhibit. We thank our Commission Advisory and Compliance Division for assisting in this effort.

136 With few exceptions, DRA examined the resource options presented in respondents' filings.

Cost estimates, by party and technology, are also presented in Exh. 50. SF/U/F questions the credibility of these estimates because of variations in costs for seemingly identical technologies (Exh. 46, p. 13, TR at 904). However, we note that some of the variation in costs is due to the fact that commercial technologies were compared to non-commercial ones (e.g., STIGs and ISTIGs).

Moreover, variations in cost estimates can be caused by factors such as the use of existing versus new sites, the degree of work necessary for electric and gas interconnections, the relative size of the units, and pollution control and environmental mitigation requirements. Hence, it is not surprising, or cause for concern, if cost estimates do vary among utilities. Indeed, in our GRC and ECAC proceedings we have regularly adopted costs for CTs that vary among the three major utilities, based on each utility's specific circumstances.

What does concerns us about the estimates presented in this proceeding, is that some do not appear to include all relevant costs. (Exh. 50, pp. 2-3.) Unfortunately, we do not have an adequate record in this phase of the proceeding to identify specific deficiencies. We agree with DRA that <u>all</u> costs should be accounted for, including land, regulatory approval and permitting, engineering and transmission costs, costs of interconnecting with the gas system for resources which use gas, and any other ancillary costs of adding the resource. For future updates, respondents should include all relevant costs and clearly describe the types of cost components (and their associated expenses) that make up their total cost estimates.

We also agree with DRA and others that we should rely less on generic cost data, and more on data reflecting the specific circumstances particular to the resource being proposed. As SDG&E points out, we indicated our preference for "fully specified" projects over generic ones in D.86-08-004.[137] For this reason, we prefer using respondents' estimates of resource costs, rather than IEP/IPC's or those developed from the CEC staff's "Technology Characterizations" reports.

Accordingly, for the Phase 1B base case, we adopt the resource types and costs presented by respondents in Exh. 50, with one exception.[138] SDG&E's Heber geothermal return-to-service option should be deleted from consideration as a candidate resource addition. We agree with DRA that, until existing litigation over Heber's brine supply is resolved, the viability of this resource is too uncertain to consider as a potentially deferrable resource for this update. We are also persuaded by the fact that, for its test year 1989 GRC, SDG&E itself excluded this resource from its resource plan, and reported that it intends to sell the project to reduce costs to customers.[139]

Our adoption today of respondents' cost estimates does not, however, constitute an endorsement of their use for other than the base case scenario in this proceeding. As we stated in D.87-11-024, suggestions to hold the utility accountable for these and other base case assumptions in other proceedings are attractive, but premature. Consistent with our prior determinations, in other proceedings where respondents develop resource cost estimates, they must justify any deviations from the

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137 See D.86-07-004, mimeo. p. 70.

138 We recognize that respondents may need to augment these base case cost estimates in Phase 1B to address our discussion of spot capacity, negotiated power purchase agreements, demonstration projects, and refurbishment/repowering options (see Sections III.D.c.,d.,f. and IV.C. above).

139 See SDG&E Exh. No. SDG&E-11, p. II-7, filed in A.87-12-003. See also Exh. 24, pp. IV-26 to IV-27, and TR at 349-357 in this proceeding.

cost estimates they have presented in this proceeding.[140] In Phase 3, we will consider proposals for improving the consistency of resource planning assumptions, including resource cost estimates, across our various proceedings.[141]

B. <u>Financial Assumptions</u>

Exh. 50 also describes the financial assumptions used by various parties to develop in-service costs and fixed charge rates. These include "S-curve" estimates of capital outlays by period, inflation rates, cost of capital, and real capital cost escalation assumptions.

In D.86-07-004, we stated that utilities should use the incremental cost of capital (as opposed to embedded costs) in developing their cost estimates. We also stated that the capital structure should be taken from the utility's most recent cost of capital filing, after removing preferred stock and adjusting debt and equity proportionately. For the cost of common equity, we directed utilities to assume that the present premium of equity over debt will remain constant.[142]

The respondents' cost of capital projections were unchallenged by other parties, and will be adopted for the Phase 1B base case. However, we note that SCE apparently included preferred stock in its capital structure, as did IEP/IPC. (Exh. 50, Attachments.) SCE should make the appropriate adjustments for its Phase 1B filing.

The inflation rates assumed by parties were similar, ranging between 4.5 and 5.3%. However, unlike capital cost assumptions, which are utility-specific, we see no reason to use

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140 See D.87-11-024, mimeo. p 27. and COL 4.

141 See TR at 184-187.

142 D.86-07-004, mimeo. pp. 85-86.

different assumptions for general inflation across utilities. For the Phase 1B base case, respondents should use an average inflation rate of 5.0% for the entire planning period. We also agree with SDG&E that, on a long-term basis, it is appropriate to assume no real capital cost escalation (SDG&E Brief, pp. 50-51.)

We adopt all other financial assumptions used by respondents in their Phase 1A filings for the Phase 1B base case.

VIII. Where We Go From Here: Scope of Phase 1B

In today's order, we have presented an implementation blueprint for this and future BRPU cycles. In Section III., we defined both in generic terms, and specifically for Phase 1B of this proceeding, what constitutes a barebones resource plan, i.e., the conceptual starting point for evaluating the cost-effectiveness of potential resource additions.[143] We also confirmed our previous determinations in A.82-04-44 et al. to give the CEC's findings great weight by adopting, as our base case, the ER7 assumptions that make up the barebones resource plan for each utility.

In Section IV. we resolved several modelling issues, including the treatment of payment reductions to variable-priced QFs, age-deration, and standby units. In Sections V. and VI. we addressed specific issues related to the application of our ICEM tests of cost-effectiveness, and other ICEM implementation issues. And finally, in Section VII., we adopted base case assumptions for candidate resource additions and financial data.

While additional issues may arise as parties gain experience with the ICEM approach, today's order should put to rest long-standing debates over how to implement our adopted LRAC methodology. We expect parties to this and future resource

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143 Table 3 and Figure 1 summarize our findings.

planning proceedings to incorporate the findings of today's order in their cost-effectiveness submittals. As we have stated throughout this and prior decisions, the methodology for assessing the cost-effectiveness of resource additions and for projecting LRACs should not vary across applications.

The next step in the BRPU process is for respondents to file revised ICEM analyses, based on today's determinations. The results of these analyses will form the Phase 1B base case. We view the Phase 1B base case as the "most likely" forecast of LRACs and QF deferrable MWs for each utility. In Phase 1B, however, we will provide parties with an opportunity to explore the uncertainties inherent in these forecasts. Based on the analysis presented in Phase 1B, we will adopt a specific MW solicitation level for FSO4.

A. <u>Phase 1B Examination of Uncertainties</u>

In their Phase 1A testimony, and during cross-examination, several parties expressed their views on what issues would be examined in Phase 1B. On November 28, 1989, ALJ Gottstein responded with the following clarifications:

> "First, let me start with what is not going to be considered in Phase 1B. We are not going to revisit methodological issues. That is, parties are not going to submit alternative scenarios based on their interpretation of the ICEM methodology, or their preferences as to how it should be implemented. The Phase 1A decision will address the interpretation issues, as they have arisen during these hearings, and provide direction on how the ICEM should be implemented. This direction will hold for Phase 1B.
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> "Second, Phase 1B is not the forum for developing, from scratch, each party's 'preferred scenario' of resource planning assumptions and modelling conventions. Phase 1A is not a preliminary exercise, to be superseded by everyone developing their own 12-year projections in Phase 1B. Rather, the scenario and IDRs [identified deferrable

> resources] resulting from the Phase 1A determinations will be the baseline for uncertainty analysis in Phase 1B.
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> "More specifically, during Phase 1B, I will direct the utilities to develop a set of sensitivities to the Phase 1A scenario of IDRs. These sensitivities will be designed to illustrate the relevant range of upper and lower bounds to a possible FSO4 solicitation... After the Phase 1A decision is issued, workshops will be held so that parties can develop a proposed set of sensitivities for my consideration." (TR at 561-561A.)

Our original intent, as expressed in prior orders, was to give respondents unlimited latitude in presenting alternative scenarios for the purpose of examining uncertainties. However, we never expected this implementation cycle to involve so much controversy over methodology and, consequently, take as long as it has. We need to streamline Phase 1B to the extent practicable, in order to reach a final determination on FSO4 in a meaningful timeframe. One way to do so is to minimize the number and detail of alternative scenarios that we examine in Phase 1B.

For the purpose of this update, we believe that examination of a few, well-selected sensitivity runs will provide us with sufficient information for making our FSO4 determinations.[144] While the specific procedural details should be discussed at a further PHC, we agree with ALJ Gottstein's intended approach for examining uncertainties in Phase 1B. At the same time, we will not preclude respondents from presenting additional

144 Parties will still be given the opportunity to present specific proposals for incorporating contingency planning into our consideration of these uncertainties. For example, one approach might be to assign some probabilities to the sensitivities; another might be to base the solicitation on the "worst case" scenario; still another might include elements of a "wait and see" strategy.

sensitivities they deem to be significant, in addition to those selected by ALJ Gottstein. However, in developing their additional sensitivities, respondents and other parties must still incorporate the findings of this order with respect to modelling conventions and methodology. (See Figure 1, Column 5.)

Accordingly, interested parties should file pre-workshop comments on the types of sensitivity scenarios they recommend for Phase 1B. As described in ALJ Gottstein's statement, these sensitivities may represent a combination of factors, such as variations in demand forecasts, coupled with variations in gas prices and/or the success rates of existing QFs.[145] There may also be sensitivities related to the assumed costs of candidate resource additions, and environmental restrictions. Alternative levels of cost-effective DSM might also be considered. The objective is to identify a limited number of factors that would capture the high and low ranges of variations, without creating detailed alternative scenarios. Comments on proposed sensitivities should be filed within forty (40) days of the effective date of this order.

We also encourage parties to this proceeding to pursue an alternative, more collaborative approach for addressing Phase 1B uncertainty issues. We recognize that each party has its own views on the types and magnitudes of base case uncertainties and how those uncertainties, if quantified, could affect the FSO4 solicitation. It may be possible for parties to this proceeding to meet in a collaborative effort to "internalize" those uncertainties, by negotiating among themselves once respondents file their Phase 1B base case results. We would then proceed under Rule 51 of the Commission's Rules of Practice and Procedure. If a

145 Any assumed changes must be consistent with the findings in this order (See Figure 1). For example, if a particular pending resource was not included in the barebones resource plan, it should not be added back in for a sensitivity run.

settlement is proposed, we will initiate our settlements and stipulations procedures in lieu of conducting further workshops to identify sensitivity scenarios for Phase 1B.[146] If successful, this collaborative approach would enable us to come to closure on this FSO4 solicitation in an expeditious manner.[147]

B. <u>SDG&E's DSM Analysis</u>

During the course of SDG&E's test year 1989 GRC, DRA and SDG&E stipulated to testing a number of uncommitted DSM programs using the ICEM approach adopted for supply-side additions.[148] In the April 19, 1989 ALJ Ruling, SDG&E was directed to present this analysis in Phase 1B:

> "In preparing this scenario, SDG&E shall use the resource plan assumptions/modelling conventions adopted in Phase 1A (except for uncommitted DSM). The choice of production cost model to perform Phase 1A and Phase 1B analysis, however, is left to SDG&E's discretion. A single production cost model should be used.
>
> "This analysis will provide useful information for Phase 1B and later phases of this proceeding. If the 'integrated' approach does have a significant impact on deferrable resources for SDG&E, then we can consider those facts in our Phase 1B deliberations. Regardless of the results, SDG&E's efforts will enhance the value of the ongoing Standard Practice Manual workshops. This exercise will

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146 Nonetheless, the pre-workshop comments should be filed, as directed above.

147 As outlined in the April 19 ALJ Ruling, for SDG&E and SCE, our final determinations on FSO4 await the outcome of the merger proceeding (A.88-12-035). However, the collaborative approach could present a stipulation on FSO4 MWs for both utilities in the event that the merger does not go forward.

148 See D.88-12-085 in A.87-12-003, FOF 97 and 98, COL 56, and Ordering Paragraph 11. See also the DRA/SDG&E <u>Joint Exhibit on Resource Plan</u> filed in A.87-12-003 (Exh. 43), pp. 5-7.

> also provide the Commission and parties with 'hands on' experience in preparation for the DSM issues in Phase 3." (April 19, 1989 ALJ Ruling, pp. 4-5.)

Accordingly, SDG&E will be required to perform this analysis for Phase 1B in addition to other sensitivity analyses directed by the assigned ALJ. In the event that an FS04 stipulation is reached, SDG&E will still be required to present the results of this analysis as part of its Phase 1B testimony.

Consistent with our determinations in PG&E's most recent GRC, SDG&E should consider only energy efficiency and load management DSM programs as alternatives to supply-side resources. In evaluating program cost-effectiveness, SDG&E should include all the costs of installing and operating the efficiency improvements, including participant costs. This is consistent with our endorsement of the Total Resource Cost test as representative of the costs and benefits which should be used to compare demand-side and supply-side resources.[149]

C. Treatment of Interutility Contracts

As discussed in Section III.D.2.c. above, we need to explore further how to enable QFs to compete against purchases from non-QF sellers, as power purchase opportunities arise in between BRPU updates. In D.87-11-024, we described several interesting ideas that were proposed during the compliance hearings in A.82-04-44 et al.[150] Interested parties recently discussed their ideas at an informal workshop, held on February 15, 1990.[151]

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149 See D.89-12-057 (in A.88-12-005 and I.89-03-033), mimeo. pp. 375-376.

150 See D.87-11-024, mimeo. pp. 28-29.

151 See ALJ Ruling on Phase 1B/Phase 1C Workshops, dated January 8, 1990, pp. 1-2.

Workshops should be continued to reach agreement on a mechanism for incorporating interutility contracts into our current update process.[152] If agreement on all issues cannot be reached, respondents and interested parties will be directed to file formal pleadings for our consideration during Phase 1B. We intend to resolve this issue by ex parte order before the end of 1990.

D. The Future of SO2 and Environmental Considerations

On January 19, 1990, respondents submitted additional ICEM analyses in compliance with the January 2, 1990 ALJ Ruling. While still preliminary, those analyses indicate that respondents are likely to need additional peaking capacity in the near future.

Our FSO4 is not available to defer the need for peaking resources. Among our short-run offers, SO2 is the only one that requires the QF to be available during periods of peak demand on the purchasing utility's system.[153] By D.86-05-024, we suspended the availability of SO2 for the signing of new contracts. In

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152 Several participants in the workshop apparently desire to broaden the scope to include potential changes to our FSO4 solicitation process, such as automatically reserving a fraction of the IDR in each update for QF, non-QF competition. This goes beyond the scope of the issue for Phase 1B. We are looking for workable proposals that can be applied to the current structure of FSO4 and our bidding procedures. Parties should focus their efforts on implementation specifics, e.g., cost-effectiveness thresholds, definitional issues, and others that were discussed at the February 15, 1990 workshop. See Interutility Contracts in the Biennial Resource Plan Update Proceeding Workshop Report, filed March 7, 1990, by the Division of Strategic Planning and Commission Advisory and Compliance Branch.

153 Time-differentiated capacity payments under SO1 and SO3 give the QF a powerful incentive to be on-line during peak periods; however, the QF does not have to meet any performance requirement for such periods, i.e., the QF delivers only "as available" capacity. In contrast, the QF under SO2 must generally be available for all on-peak hours in the peak months (subject to a 20% allowance for forced outages in any month) in order to receive full capacity payments.

D.87-11-024, convinced of SDG&E's need for peaking generation in the near future, we reinstated SO2 for a limited solicitation in SDG&E's service territory.

As we discussed in D.88-09-026, with some restructuring, SO2 has a continuing role to play in a balanced portfolio of standard offers. As we stated in D.87-11-024, "Standard Offer 2 does not avoid new resources, but rather backs down existing resources. This is the least-cost strategy whenever a utility would not incur energy-related capital costs."[154] Hence, this offer is particularly well-suited for periods when there is a short-run need for "peakers" until the utility can add a cost-effective baseload or intermediate load resource. Based on the filings made in response to the January 2, 1990 ALJ Ruling, this may be the case for some or all respondents over the next 3-6 years. We originally planned to consider the reinstatement of SO2 after completion of Phase 1. However, the recent Phase 1A filings have convinced us that a more expedited schedule is warranted. Accordingly, we will consider the issue of SO2 reinstatement during Phase 1B.

The possibility that some respondents will need to build or return-to-service peaking resources, which are typically oil or gas-fired, also calls for more expeditious consideration of the relative environmental impacts among resource options. We had originally scheduled consideration of nonprice adders for Phase 1C, contingent upon an FSO4 solicitation during this update cycle. However, we now believe that our consideration of SO2 reinstatement issues provides an excellent forum for considering proposals to include environmental adders and/or to incorporate environmental criteria into the SO2 solicitation process. Assuming that we do reinstate SO2 in some form for one or more of the utilities, we may

154 D.87-11-024, FOF 22.

be able to incorporate environmental considerations in the next round of SO2's as a test case.[155]

We encourage parties to work collectively on a consensus approach for that purpose. The informal workshops held earlier this month should be continued to develop a consensus approach for incorporating environmental considerations into an SO2 solicitation.[156] If consensus cannot be reached, interested parties will have the opportunity to present their position as part of their Phase 1B filings on the reinstatement of SO2. Parties should keep in mind that, for Phase 1B, we are looking for a workable approach that we can adopt for test case purposes only.

No later than fifty (50) days from the effective date of this order, respondents and interested parties should file and serve their positions on (1) under what circumstances should SO2 be made available, (2) what MW limits should apply when it is available, and (3) how to address potential oversubscription problems. If consensus cannot be reached via informal workshops, respondents and interested parties should also file their positions on how to incorporate environmental considerations into the SO2 solicitation process, as a test case. Parties should specifically comment on the proposal we outlined in D.88-09-026 for regulating the availability of SO2.[157] These should be filed at the Commission's Docket Office, and served on all parties of record, including the state service list. Reply comments should be filed

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155 This can be done in a variety of ways, including quantifying the benefits of reducing environmental impacts in our cost-effectiveness analysis, computing payment adders to QFs that avoid those impacts, and/or incorporating environmental criteria into a bid selection.

156 See Administrative Law Judge's Ruling on Phase 1B/Phase 1C Workshops, dated January 8, 1990.

157 See D.88-09-026, mimeo. pp. 40-42.

and served no later than ten (10) days after the initial positions are filed. We intend to resolve this issue by ex parte order as soon thereafter as possible.

E. Phase 1B Compliance Filing Requirements

Respondents should file their Phase 1B base case analyses, and serve them on all appearances and the state service list in this proceeding, no later than twenty (20) days from the effective date of this order. Respondents should deliver these filings on an expedited (i.e., overnight) basis to key parties, and include in that delivery copies of all workpapers and ELFIN input and output files (on hard copy and diskette).[158]

These compliance filings should clearly summarize the Phase 1B base case results in terms of the type, MW level and timing of all resources that pass the ICEM cost-effectiveness testing procedure. Respondents should clearly indicate which of these resources they consider nondeferrable by QFs, and make the requisite nondeferrability showing. The filings should also present year-by-year LRACs, based on the fully built-out resource plan, i.e., the resource plan that includes all resources passing the ICEM tests of cost-effectiveness.

Respondents should also include the following information in their compliance filings:

(1) A list of all potential additions included in the ICEM prescreening and the additions subsequently considered in the ICEM as a result of that screening;

(2) Any year(s) in which the CEC target reserve margins are not met or exceeded;

(3) Any year(s) in which a CT would not have passed the ICEM analysis when the ERI is one or greater;

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158 For the purposes of this order, the key parties are: PG&E, SCE, SDG&E, DRA, SF/U/F, IEP/IPC, and CEC.

(4) A comparison between using the CEC's ER7 illustrative loads and trending, for connecting short-run with long-run demand forecasts (see Section VI.A. above);

(5) Information on short-term and long-term reserves, as described in Section IV.C. above;

(6) Variable O&M estimates used for post-processing, including a clear explanation of their derivation and source (see Section IV.F. above); and

(7) A list of all units assumed to be capable of cycling on a daily basis.

Written comments on these compliance filings are to be filed no later than thirty-five (35) days from the effective date of this order. The purpose of these comments is to identify any areas where respondents may not have complied with the directives in today's order. These areas should be minimal, given the fact that we have already considered one round of comments to respondents' compliance filings, submitted in response to the January 2, 1990 ALJ Ruling. In developing their base case filings, we remind respondents that they are expected to carefully and conscientiously implement the policies and directives expressed in today's decision.

The procedural schedule and requirements for additional Phase 1B filings, workshops, and prepared testimony will be set by further Ruling.

<u>Findings of Fact</u>

1. The purpose of this decision is to adopt base case assumptions for determining whether California's IOUs need additional resources over the next 12 years and, if so, to identify those that are potentially deferrable by QFs.

2. Prices to QFs under our long-run standard offer (FSO4) are based on deferrable resources identified within the first eight years of the planning period.

3. In A.82-04-44 et al., we adopted an LRAC methodology for identifying cost-effective resources that are potentially deferrable by QFs.

4. The overall purpose of our adopted LRAC methodology is to create a pricing structure that captures to the extent possible the efficiency and other benefits of perfect competition in electricity generation.

5. Our LRAC methodology uses a simplified generation resource plan approach. Under this approach, the utility's future least-cost resource plan is developed, using an iterative method for evaluating the cost-effectiveness of potential resource additions (i.e., the ICEM).

6. The generation resource plan approach does not have to be varied depending upon the purpose for which it is used.

7. The ICEM starts with a utility's barebones resource plan, consisting of the resources described in Figure 1, and then tests candidate resource additions using first-year and life-cycle tests of cost-effectiveness.

8. The term barebones is a methodological concept referring to those resources that are assumed in the utility's resource plan before testing candidate resource additions for cost-effectiveness.

9. The base case resource plan refers to a specific set of assumptions assumed to represent the "most likely" scenario, including forecasts of demand, prices, and availabilities of the

resources in the barebones plan, as well as the costs and operating characteristics of candidate resource additions.

10. Consistent with our prior determinations in A.82-04-44 et al., parties to this proceeding were directed to use the CEC's ER7 supply and demand assumptions for the base case ICEM analysis.

11. In using the ER7 assumptions, parties were directed to correct for any inconsistencies in the CEC's definition of a barebones resource plan, relative to this Commission's definition.

12. ER7 supply assumptions include long-term projections of as-available (S01 and S03) QFs not currently under contract, as well as potential self-generation.

13. ER7 supply assumptions include the four successful QF bids for SDG&E's S02 solicitation (totalling 182.2 MW) that we identified in D.89-02-017.

14. ER7 supply assumptions include four solar projects (Luz SEGS IX-XII) and a cogeneration project (Harbor/Chaplin) in SCE's service territory that are anticipated to come under CEC siting review within the year.

15. ER7 supply assumptions include two exchange agreements currently under negotiation between PG&E and Seattle City Light, and PG&E and Puget Sound.

16. In D.85-07-022, we concluded that the price determined under our adopted LRAC methodology must be calculated without including QFs who are not in existence, but will be brought on-line as a result of that price.

17. In D.86-07-004, we rejected utility proposals to establish broad categories of generically nondeferrable resources.

18. In D.86-07-004, we required utilities to make a four-part showing of nondeferrability on a project-by-project basis, including a showing of cost-effectiveness.

19. In D.86-07-004, we determined that FS04 should be based on avoidable baseload and intermediate resources, while peaking resources should be considered nondeferrable by QFs.

20. In D.86-07-004, we determined that a utility should not be considered committed to a project for which construction has not started or major regulatory approvals are pending.

21. In D.86-07-004 we permitted utilities to demonstrate commitment (or the opposite) on a project-specific basis where our guidelines seemed not to be dispositive.

22. In D.86-11-071 and D.87-05-060, we stated that QF projects with signed contracts are to be assigned a projected success rate, based on an objective standard, before including them in the barebones resource plan.

23. In D.87-05-060, we determined that an interutility contract should be fully executed by both sides before including it in the barebones plan. However, we permitted the utility to make a specific showing that a particular purchase is committed, based on appropriate documentation.

24. In D.87-05-060 we stated that, consistent with our treatment of QF signed contracts, the uncertainty associated with regulatory review of signed interutility contracts should be accounted for in a projected success rate for each purchase.

25. DRA's testimony in A.82-04-44 et al. only included forecasts of future QFs for the "inframarginality test", which was subsequently eliminated from the ICEM tests in D.86-07-004.

26. Including forecasts of unsigned SO1 and SO3 QFs in the barebones resource plan imputes a policy preference, similar to a finding of nondeferrability, for as-available, short-run QF contracts relative to FSO4, our long-run resource plan based offer.

27. The price for energy and capacity under FSO4, based on the cost of new resources, should generally be lower than forecasted SRAC payments to as-available QFs.

28. In D.88-09-026, we did not address the issue of how to differentiate between committed and uncommitted self-generation, as some parties urged us to do.

29. Under our as-available standard offers, QFs have the option of changing from a simultaneous purchase and sale to surplus sale on a yearly basis.

30. QFs elect to change their purchase/sales arrangements based on short-run pricing signals, which we update as frequently as every three months.

31. There is no clear distinction, in terms of the impact on a utility's system, between an as-available QF and self-generator.

32. Estimates of future QF contracts and self-generation are made without identifying specific sites or considering development milestones.

33. Unlike interutility MOUs or contracts under negotiation, a standard offer is a contract that is complete, and available at the QF's sole option.

34. It is not 100% certain that a QF who tenders a successful bid for SO2 or FSO4 will sign the standard offer.

35. Excluding QFs that have tendered a winning bid for a standard offer solicitation, but have not yet signed the contract, could lead to a situation where a subsequent bid cycle resolicits bids for all of the deferrable MWs identified in the previous cycle.

36. Subsequent to the issuance of ER7, two of the winning bidders for SDG&E's SO2 solicitation did not elect to pursue their projects.

37. None of the parties to this proceeding presented any estimates of success rates for the remaining two active participants in SDG&E's SO2 solicitation.

38. None of the parties to this proceeding presented any estimates of success rates for the Luz SEGS IX-XII projects.

39. The Harbor/Chaplin project does not have a signed contract with any utility, and is currently pursuing negotiations with LADWP.

40. PG&E has executed exchange agreements with Seattle City Light and Puget Sound. PG&E has been negotiating with BPA for transmission access for these agreements since August 1988, and does not yet have complete access to deliver the power.

41. PG&E has not yet sought approval from FERC for these purchase agreements, and does not plan to do so before mid-1991 (for Puget Sound) and mid-1992 (for Seattle City Light).

42. PG&E did not conduct a cost-effectiveness analysis of these two agreements and testified that it would be difficult to do so before negotiations were completed.

43. Including contracts under negotiation in the barebones resource plan amounts to an imputation of cost-effectiveness to purchases from sellers that have not bound themselves to specific terms, and may be unwilling or unable to agree on terms acceptable to the utility.

44. Including contracts under negotiation in the barebones resource plan creates undesirable incentives in the energy market and undermines our objective of creating a "level playing field" for consideration of all resource options.

45. We have not yet fully explored the issue of how to enable QFs to compete with power purchase opportunities that materialize between updates.

46. ER7 supply assumptions include the renewal of PGE's current storage contract with SDG&E, which expires in 1998.

47. PGE's renewal of its storage contract with SDG&E is highly uncertain at this time.

48. ER7 supply assumptions include two IOU projects for which construction has not started, or regulatory approvals are pending: SDG&E's 100 MW South Bay 3 augmentation, and SDG&E's 30 MW retrofit of inlet air coolers.

49. ER7 supply assumptions include the Kerr McGee Argus Cogeneration Expansion (ACE) and Coolwater Coal Gasification

conversion (Coolwater) demonstration projects in SCE's planning area.

50. The ACE demonstration project is a QF project owned by Kerr-McGee Chemical Corporation.

51. The record in this proceeding is not clear regarding the status of the purchase agreement between SCE and Kerr-McGee (e.g., whether or not it is fully executed; the term of the contract, etc.).

52. The ACE demonstration project is currently under construction and has CEC approval to operate beyond the demonstration phase.

53. The Coolwater project has completed its demonstration phase and negotiations are currently underway to sell the project to another party.

54. A demonstration project, by definition, may or may not become commercially viable and cost-effective.

55. Including a demonstration project in the barebones resource plan beyond the demonstration phase assumes that it will be both technically successful and cost-effective beyond the demonstration phase.

56. Including a demonstration project in the barebones resource plan beyond the demonstration phase penalizes all other resource options, including QFs, that could compete using commercially available technologies.

57. The CEC planning areas for SCE and PG&E include various Muni loads and resources.

58. ER7 supply assumptions include pending Muni resources, i.e., resources under development which may materialize in the planning period, but await regulatory approval.

59. In D.88-09-026, we determined that respondents should adopt the treatment of residual Muni loads preferred by the CEC.

60. For ER7, the CEC makes two related assumptions: (1) the IOUs have no additional obligation to meet the capacity and energy

needs of the Muni utilities beyond the obligations imposed by existing contracts, and (2) Muni utilities will take steps to secure resources on their own to meet their future needs.

61. SCE's and PG&E's FSO4 payments to QFs would reflect the future resource needs of Muni utilities if pending Muni resources were excluded from the barebones resource plan.

62. ER7 supply assumptions include 1,000 MW statewide of spot capacity purchases from the Northwest, and the CEC finds this level of spot capacity to be nondeferrable.

63. In making its ER7 findings, the CEC did not subject spot capacity purchases to the ICEM tests of cost-effectiveness; nor could it have constructed a barebones resource plan, consistent with our determinations today, in order to do so.

64. Removing spot capacity purchases and/or PG&E's Puget Sound and Seattle City Light exchange agreements from the resource plan without redesignating the firm energy to nonfirm would result in a lower level of total nonfirm energy than adopted in ER7.

65. In D.87-11-024 and D.88-09-026, we determined that cost-effective uncommitted DSM is nondeferrable by QFs

66. Our current procedure for evaluating DSM programs considers the results of several cost-effectiveness tests, each designed to reflect the different set of costs and benefits experienced by program participants, all ratepayers, the utility and society as a whole.

67. Our cost-effectiveness testing procedures for DSM are described in the CEC/CPUC Standard Practice Manual, developed jointly by the two Commission staffs.

68. We intend to further explore the potential for integrating our demand- and supply-side cost-effectiveness testing methods in Phase 3 of this proceeding, or other appropriate proceedings that may follow from the Statewide Collaborative Process.

69. During the course of SDG&E's test year 1989 GRC, DRA and SDG&E stipulated to testing a number of uncommitted DSM programs using the ICEM approach adopted for supply-side additions. In D.88-12-085, we adopted that stipulation.

70. In D.87-11-024, we stated that the CEC should present its adopted forecasts of uncommitted DSM for review by DRA and other parties, in terms consistent with the interagency staff enhancements to the Standard Practice Manual.

71. The CEC's ER7 projections of nondeferrable DSM were developed in a manner consistent with the cost-effectiveness criteria contained in the Standard Practice Manual.

72. ER7 supply assumptions do not include SCE's Chino Battery storage project, which is a 10 MW project currently being demonstrated as a pumped storage unit.

73. The ER7 data set for PG&E does not include 62 MW of QF geothermal resources that were identified in the ER7 supply assumptions.

74. ER7 supply assumptions do not include all of the additional DSM authorized in SDG&E's test year 1989 GRC.

75. ER7 supply assumptions do not include the Axis steam plant and CT resources, which were integrated with SCE's main system when the Blythe-Eagle Mountain interconnection was closed on October 31, 1988.

76. ER7 supply assumptions include the Rancho Seco Nuclear Plant as an existing, operating resource.

77. ER7 designates the SCE/LADWP Exchange Agreement as a pending resource.

78. The SCE/LADWP Castaic exchange contract has been in effect since May 8, 1988 and does not require any further regulatory approvals.

79. On June 6, 1989, Sacramento voters rejected a proposal to allow SMUD to continue operating the Rancho Seco Nuclear Plant.

80. On September 1, 1989, the ER7 Standing Committee issued its recommended changes to the ER7 data sets to reflect the shutdown of Rancho Seco.

81. In D.88-03-079, we adopted the QF-in/QF-out method for calculating energy payments to variable-priced QFs.

82. In D.88-03-079 we considered and rejected proposed modifications to the QF-in/QF-out method that would account for resources a utility would substitute for variable-priced QFs in the QF-out run.

83. In D.88-03-079 we stated that, depending on changes to the electric market, we might reconsider the QF-in approach.

84. Under the QF-in or QF-in/QF-out methods, the addition of a cost-effective new resource will typically reduce energy payments paid to variable-priced QFs.

85. We routinely include the effect of adding a new resource in the calculation of QF prices.

86. All ratepayers directly benefit from the QF payment reductions that occur as the result of a utility's decision to add a cost-effective resource to its resource plan.

87. LRACs are evaluated from the perspective of the ratepayer.

88. QF payment reductions provide societal efficiencies by removing the least efficient QF operators and forcing the remainder to improve their efficiency.

89. Implementing the QF-in/QF-out method for each iteration of the ICEM analysis would require running at least twice as many production simulations.

90. The ICEM results submitted by respondents in response to the January 2, 1990 ALJ Ruling were largely unaffected by the additional QF-in/QF-out iteration.

91. To reflect the decline in available capacity from aging oil/gas plants, ER7 removed a certain amount of "age-derated" capacity from each utility's resource plan.

92. In calculating age-deration amounts, ER7 adopted a methodology that assumes a linear decline from full rating to zero as plants go from 35 to 60 years of age.

93. ER7 did not state how age-deration should be incorporated into the resource plans and production cost models used to conduct cost-effectiveness analysis.

94. On November 27, 1989, respondents, DRA, CEC, and IEP/IPC filed a joint workshop report with their agreed upon approach for applying the ER7 age-deration assumptions in Phase 1B.

95. Respondents, DRA, CEC, and IEP/IPC agree that age-deration should be incorporated in the calculation of reserve margins and the ERI. For this purpose, they agree that the utility would first count its standby units towards the required age-deration levels.

96. Respondents, DRA, CEC, and IEP/IPC also agree that age-deration should not be incorporated into the production cost simulation.

97. Standby units are oil and gas plants that are potentially available for operation, but generally require additional expenditures and/or start-up time before they can be placed into service.

98. In our ECAC proceedings, we distinguish between standby units that can be restarted in a short time with little or no expense (short-term reserves), and standby units that require significant time and investments to place into daily operation (long-term reserves).

99. In D.88-11-052 and D.89-12-015 we determined that short-term reserves should be modelled as being available over the entire forecast period, when determining the short-run need for capacity and for production cost purposes.

100. Applying age-deration levels first to standby units excludes all short-term reserves from reserve margin and ERI

calculations, unless the the system's total MW capacity of standby units is greater than the ER7 age-deration levels.

101. In its January 19, 1990 compliance filing, PG&E restored age-derated capacity from short-term reserve units by testing those units for cost-effectiveness.

102. ER7 adopted age-deration in order to force utilities to demonstrate, rather than assume, the continuing economic viability of their aging plants.

103. Testing a unit in short-term reserves for cost-effectiveness does not explicitly consider the costs of various life-extension options, as intended by ER7.

104. In ER7, the CEC considered age-deration in conjunction with its adopted target reserve margins.

105. Refurbishment or repowering options extend the useful life of a standby unit.

106. Considering the cost-effectiveness of refurbishments or repowering options for the purpose of restoring age-derated capacity is consistent with CEC's intent in ER7.

107. Applying the age-deration levels first to standby units is a proxy for the sum of age-deration capacity, across all other plants, that should be excluded in evaluating the need for capacity.

108. In ELFIN Version 1.7, there are basically two ways to designate firm capacity for commitment purposes: either as a minimum constrained "CM" unit, or as a quick-start "CP" unit.

109. Units that can be shut down during the evening hours and restarted in the morning (e.g., combined cycle units) fall somewhere between the minimum constrained and quick-start ELFIN designations.

110. The ER7 data set uses a "CM" designation for all combined cycle units.

111. The relative dispatchability of potential resource additions within the ELFIN model can substantially affect the results of the cost-effectiveness tests.

112. Parties to this proceeding generally support SCE's hybrid approach for modelling combined cycle units. This approach retains the "CM" designation but lowers the minimum load points on these units during the off-peak periods.

113. In its ER7 data set, the CEC models as-available QFs as firm, dependable capacity, but effectively derates that capacity to take account of the fact that all QFs may not be operating simultaneously or at 100% nameplate capacity.

114. Treatment of as-available QFs as firm dependable capacity, in the aggregate, is consistent with our treatment of those resources in ECAC proceedings.

115. When variable O&M is included in the ELFIN data set, ELFIN Version 1.7 will make dispatch decisions based on variable costs that include O&M.

116. Variable O&M should be accounted for in evaluating the cost-effectiveness of new resource additions.

117. One way to account for O&M costs in the ICEM analysis, without including those costs in the model dispatch, is to calculate variable O&M costs by multiplying the kWh from each unit by the appropriate unit price (i.e., post-processing).

118. Post-processing requires a separate calculation for each resource in the utility's resource plan, which can be facilitated through the use of electronic spreadsheets.

119. An alternative to post-processing is to estimate an average O&M rate for existing units, and subtract that rate from the total fuel costs of the candidate resource.

120. Averaging can produce inaccurate results when plants have a wide range of variable O&M costs.

121. Post-processing requires the modeller to clearly present all assumptions used for variable O&M costs.

122. In D.89-09-093, we directed PG&E to use the variable O&M estimates it filed in CEC's CFM-7 proceeding for the 1989 ECAC case.

123. Respondents' estimates of variable O&M costs, as filed with the CEC in CFM-7, provide reasonable base case values, in light of the limited purpose and record of this proceeding, of each operational generating unit's marginal O&M costs.

124. Only PG&E recommends changing the ELFIN "COMMT" feature to "NCOMMT", which would base model commitment on rated capacity, instead of derated capacity.

125. SCE and SDG&E recommend a number of relatively minor adjustments to the modelling conventions presented in the ER7 data set, none of which were challenged as being incorrect or unreasonable.

126. In D.86-07-004, we adopted DRA's two-part test of cost-effectiveness, the first-year and life-cycle tests, for our ICEM analysis of potential resource additions.

127. Parties to this proceeding disagree over the appropriate sequence for applying the ICEM tests of cost-effectiveness to potential resource additions.

128. The time-sequential approach starts with the initial year of the planning horizon, and tests those options passing the first-year test in that year for life-cycle cost-effectiveness. If it is cost-effective to add more than one resource in a given year, comparisons of life-cycle tests are tie-breakers. The evaluation proceeds to subsequent years of the planning horizon after sufficient cost-effective resource additions have been added to meet reserve margins.

129. The non-sequential approach first ranks all resource options based on life-cycle cost-effectiveness, and then adds the most cost-effective resource in the year it first passes the first-year test. The evaluation then proceeds to the next cost-effective

resource until sufficient cost-effective resource additions have been added to meet reserve margins.

130. The non-sequential approach enables the planner to explicitly consider attractive resource options that are available later in the planning horizon.

131. The non-sequential approach relies on a decision rule that would add resources as much as 30 years into the future, thereby posing the risk of overcommitment to technologies for which ultimate development is uncertain.

132. The non-sequential approach is more burdensome to implement than the time-sequential approach, since its decision rules require a life-cycle cost of analysis of every potential resource addition.

133. Relative to the time-sequential approach, the non-sequential approach is more likely to result in a resource plan with either too little or too much capacity in certain years.

134. One way of correcting for the resource planning anomalies that arise using the non-sequential approach is to relax the first-year test.

135. Application of the cost-effectiveness tests under the time-sequential approach involves a consistent, verifiable set of decision rules.

136. There is no evidence that the time-sequential approach compromises to any significant extent the accuracy of results, relative to the non-sequential approach.

137. In their Phase 1A filings, PG&E, SCE, SDG&E, and DRA all used different prescreening techniques to reduce the number of resource options included in the ICEM analysis.

138. Prescreening of resource options can substantially reduce, or change the nature of, the types of resources considered potentially deferrable by QFs.

139. PG&E's method best captures the intent of prescreening, namely, to screen out the most expensive options for each operating mode.

140. A ramped fixed cost stream can be constructed for all resource options, based on the fixed revenue requirements for the life of each option (i.e., single lifetime approach).

141. A ramped fixed cost stream can also be constructed for resource options, based on the assumption that each option can be infinitely replicated at some inflation rate (i.e., infinite repetition approach).

142. The single lifetime approach can be used for all resource options, regardless of whether or not that option is, in actuality, infinitely replicable.

143. Using either the single lifetime or the infinite repetition approach appears to yield identical results.

144. Relieving power purchase options from the requirements of the first-year test puts that resource at an advantage not enjoyed by any other supply option.

145. If a potential power purchase offer cannot pass the first-year test, then the utility can negotiate the starting date of the contract to ensure that it does.

146. Subjecting SDG&E's DSM programs in Phase 1B to the first-year test will give us an indication of how DSM programs fare when compared on equal footing with supply-side resources.

147. The 12-year planning horizon we adopted in D.86-05-024 is a logical choice for the ICEM planning horizon.

148. In D.86-05-024, we determined that the resource plan filings should show any cost-effective resource as added in the first year that it becomes cost-effective, regardless of whether the utility itself could have built the resource in that length of time.

149. B/C ratios capture differences in size, lifetime, and capital intensity among various resource options.

150. By definition, the life-cycle test of cost-effectiveness will require some form of extrapolation beyond ER7's 20-year planning horizon.

151. Extending the ER7 data sets, as a form of extrapolation, would be a speculative and arduous task.

152. Extrapolating production cost savings is a practical middle ground between truncating the life-cycle analysis and extrapolating the ER7 data sets.

153. In its Phase 1A ICEM analysis, SDG&E evaluated technologies that are not currently commercially available, and would not have been commercial during the 12-year planning period.

154. Including commercially unavailable technologies in the resource planning process increases the risk of overcommitting to technologies for which ultimate development is uncertain, and for which benefits are dependent upon long-term, relatively less certain production cost savings.

155. Completely ignoring the potential of technologies that have a strong likelihood of becoming commercial during the planning period would disadvantage ratepayers.

156. ER7 adopted its long-range forecasts beginning in 1992, but also presented illustrative loads for each utility for the 1989-1991 period.

157. In D.88-09-026, we directed respondents to choose among three alternative approaches for connecting our adopted short-range demand forecast with the CEC's ER7 adopted long-range forecast: (1) trending between the two forecasts, (2) repetition of our short-range forecast or (3) repetition of the CEC's long-range forecast in the intervening years

158. In their Phase 1A filings, PG&E and SDG&E used the ER7 illustrative loads for the years 1989 to 1991.

159. It is necessary to make significant adjustments to our adopted ECAC short-range demand forecast to put it on a comparable basis with the ER7 long-range forecast.

160. Utility system operators do not consider transportation-related gas costs in selecting which units to dispatch.

161. A long-term resource addition is likely to avoid not only the commodity costs of gas, but also the long-run marginal costs of the gas distribution system.

162. Until we are able to develop long-run marginal gas costs, embedded transportation-related gas costs are our only proxy for the incremental system costs that are deferrable by non-gas fired (or very gas efficient) resource additions.

163. ERCCs are calculated by taking the difference between the fixed costs of a specific resource option and those of the utility's marginal capacity investment, assumed to be a CT.

164. In D.86-07-004, we stated that a peaker essentially does not have ERCCs.

165. In D.86-07-004 and D.87-11-024, we stated that it was the absence of ERCCs that dictated our decision not to authorize a peaker-based standard offer.

166. A resource that does not have any ERCCs will only be added to the resource plan if there are no cost-effective baseload or intermediate resource options to meet short-term reliability needs and reduce marginal operating costs.

167. Using B/C ratios as tie-breakers in the ICEM analysis will indicate if a resource with no ERCCs is needed as a shortage resource, or if there are baseload or intermediate load resources that should be added instead for both reliability and energy saving purposes.

168. A resource with no ERCCs which passes the ICEM tests of cost-effectiveness is a "peaker", as we have used the term in D.86-07-004.

169. Given our current use of a CT as the utility's marginal capital investment, any resource with fixed costs that is lower than those of a CT will, by definition, have no ERCCs.

170. The need for capacity on the utility system at any point in time is measured by multiplying the ERI by the value of a CT.

171. By definition, a CT will be cost-effective in any year in which the ERI is 1.0 or greater.

172. Variations in cost estimates for seemingly identical resources can be caused by factors such as the use of existing versus new sites, the degree of work necessary for electric and gas interconnections, the relative size of the units, and pollution control or environmental mitigation requirements.

173. Use of generic cost data does not adequately reflect specific factors that make up a utility's resource costs.

174. Respondents provided utility-specific cost estimates for their candidate resource additions.

175. SDG&E is currently in litigation with the brine supplier for the Heber geothermal plant.

176. For its test year 1989 GRC, SDG&E excluded Heber from its resource plan, and reported that it intends to sell the project to reduce costs to customers.

177. The viability of Heber as a return-to-service option is too uncertain at this time to be considered as a potential resource addition.

178. In D.87-11-024, we directed respondents to justify any deviations from the BRPU base case assumptions in other proceedings where they develop and present resource planning assumptions.

179. In Phase 3, we will consider proposals for improving the consistency of resource planning assumptions, including resource cost estimates, across our various proceedings.

180. In D.86-07-004, we directed respondents to: (1) use the incremental cost of capital, (2) take the capital structure from the utility's most recent capital filing, after removing preferred stock and adjusting debt and equity proportionately, and (3) assume the present premium of equity over debt in developing their cost estimates.

181. In its Phase 1A filing, SCE included preferred stock in its capital structure.

182. The inflation rates assumed by parties in Phase 1A ranged from 4.5 to 5.3%.

183. Unlike capital cost assumptions, general inflation assumptions are not utility-specific, and should not vary across utilities.

184. There was no evidence presented in this proceeding to demonstrate that, over the long term, the real costs of capital will escalate.

185. This BRPU cycle involved far more controversy over interpretation and implementation of our adopted LRAC methodology than we anticipated.

186. It is necessary to streamline Phase 1B to the extent practicable, in order to reach a final determination of FS04 in a meaningful timeframe.

187. For the purpose of this update, examination of a few, well-selected sensitivity runs will provide us with sufficient information for making our FS04 determinations.

188. It may be possible for parties to this proceeding to meet in a collaborative effort to internalize the uncertainties inherent in the base case, and negotiate a mutually acceptable FS04 solicitation.

189. During the course of SDG&E's test year 1989 GRC, DRA and SDG&E stipulated to testing a number of uncommitted DSM programs using the ICEM approach adopted for supply-side additions.

190. Among our short-run standard offers, SO2 is the only one that requires the QF to be available during periods of peak demand on the purchasing utility's system.

191. SO2 is currently suspended for PG&E, SCE, and SDG&E.

192. In D.87-11-024, we found that (1) SO2 does not avoid new resources, but rather backs down existing resources, and (2) this

is the least-cost strategy whenever a utility would not incur ERCCs.

193. We had originally planned to consider the reinstatement of SO2 after completion of Phase 1.

194. The Phase B base case scenario, as defined in this order, may indicate a need for peaking resources (i.e., resources with no ERCCs) for some or all respondents during the planning horizon.

195. The utility's peaking resources are typical oil- or gas-fired.

196. Our current pricing and bidding procedures for QF power do not take account of nonprice factors, such as environmental impacts.

197. We had originally planned to consider nonprice adders contingent upon an FSO4 solicitation during this update cycle.

<u>Conclusions of Law</u>

1. The barebones resource plan should be the consistent starting point for all applications of the ICEM, and for all planning scenarios.

2. The barebones resource plan should consist of existing and committed resources augmented only by the types of resources set forth in this order and summarized in Figure 1.

3. The ER7 supply and demand assumptions that make up the barebones resource plan should be used for the base case, or "most likely" scenario for this update.

4. Forecasts of future QFs not under contract should be excluded from the barebones resource plan.

5. Consistent with our treatment of future as-available QFs, forecasts of self-generation additions should be excluded from the barebones resource plan.

6. For the Phase 1B base case and sensitivities, all post-1991 additions to as-available QF contracts and self-generation should be set to zero, except for projects with negotiated

deferrals, as reflected in executed amendments to their interim SO4 contracts. QF projects within the latter category should be included in the barebones resource plan.

7. For the Phase 1B base case and sensitivities, respondents should include the CEC's estimates for self-generation through 1991. After 1991, all additions to self-generation should be set to zero.

8. QFs with signed contracts, including negotiated deferrals, or QFs who have won an SO2 or FSO4 solicitation should be included in the barebones resource plan. Their projected energy and capacity deliveries should be discounted by estimated success rates, based on an objective standard. For QFs who have won an SO2 or FSO4 solicitation, but have not yet signed their contracts, this success rate should reflect the possibility that the QF may not ultimately sign the contract.

9. The two projects that have dropped out of SDG&E's SO2 solicitation (totalling 52.2 MW) should be excluded from SDG&E's barebones plan in Phase 1B.

10. For the remaining active projects in SDG&E's SO2 solicitation (Bonneville and Luz SEGS 13, totalling 130 MW), a 50% success rate represents a reasonable middle ground between the unacceptable extremes of 0% and 100%, and should be assumed for the Phase 1B base case. Alternative success rates may be considered for the Phase 1B sensitivities.

11. The Luz SEGS IX-XII solar units should be included in SCE's barebones resource plan at a projected success rate.

12. A 50% success rate for the Luz SEGS IX-XII projects is a reasonable middle ground between the unacceptable extremes of 0% and 100%, and should be assumed for the Phase 1B base case. Alternative success rates may be considered for the Phase 1B sensitivities.

13. The Harbor/Champlain project should be excluded from SCE's barebones plan and should not be considered for the Phase 1B sensitivities.

14. In Phase 1B we should examine further the issue of how to enable QFs to compete with power purchase opportunities that materialize between updates.

15. For the Phase 1B compliance filings, respondents should treat agreements currently under negotiation in the following manner: If a utility does not believe it can reasonably estimate the final terms of contracts it is currently negotiating, it should remove those resources from the barebones resource plan and all sensitivities. If a utility believes that current negotiations are sufficiently mature to permit it to project prices for the Phase 1B compliance filing, it should do so, and treat the unconsummated purchase option as a candidate resource, subject to the ICEM analysis.

16. The Puget Sound and Seattle Power Light purchase agreements should be excluded from PG&E's barebones resource plan in Phase 1B. Consistent with Conclusion of Law 14, PG&E may subject these agreements to the ICEM tests of cost-effectiveness.

17. In removing the Puget Sound and Seattle City Light exchange agreements from the barebones resource plan, PG&E should redesignate the firm energy associated with these contracts to nonfirm, consistent with Exh. 37.

18. The renewal portion of the PGE storage contract should be excluded from SDG&E's Phase 1B barebones resource plan.

19. Absent a specific demonstration of commitment, a utility should not include in the barebones plan any IOU project for which construction has not started or major regulatory approvals are pending.

20. Absent a specific showing of commitment, an IOU demonstration project should be included in the barebones resource

plan during the demonstration phase only if it has received all regulatory approvals and construction has commenced.

21. Beyond the demonstration phase, an IOU demonstration project should be evaluated as a potentially deferrable resource, and subjected to the ICEM tests of cost-effectiveness.

22. QF-owned demonstration projects should be included in the barebones resource plan at a projected success rate only if there is an executed contract for power purchases beyond the demonstration phase.

23. For its Phase 1B compliance filing, SCE should include the Coolwater project in the barebones resource plan during the demonstration phase only. Beyond the demonstration phase, the project should be evaluated as a potentially deferrable resource, and subjected to the ICEM tests of cost-effectiveness.

24. If SCE has fully executed a contract with Kerr-McGee Chemical Corporation for the ACE demonstration project beyond the demonstration phase, then this resource should be included in SCE's Phase 1B base case filing at a projected 100% success rate. If, however, the contract is not fully executed, as of the effective date of this order, then SCE should include the ACE demonstration project in the barebones resource plan during the demonstration phase only. Beyond the demonstration phase, the project should be evaluated as a potentially deferrable resource, and subjected to the ICEM tests of cost-effectiveness.

25. SDG&E's 100 MW South Bay 3 augmentation 30 MW retrofit of inlet air coolers should be excluded from the Phase 1B barebones resource plan and subjected to the ICEM tests of cost-effectiveness.

26. IOU ratepayers should not pay QFs based on Muni utility needs, unless the IOU is contractually obligated to meet those needs.

27. For the Phase 1B base case and sensitivities, PG&E should include Burbank and Glendale purchases and exchanges with PGX,

Northwest purchases over the Muni portion of COTP, and MSR's access to San Juan #4 in the Phase 1B barebones resource plan.

28. For the Phase 1B base case and sensitivities, SCE should include the Resale Cities Southwest contract and Northwest purchases over the Muni portion of COTP in the barebones resource plan.

29. For their Phase 1B base case filing, respondents should exclude the ER7 spot capacity purchases from the barebones resource plan and subject them to the ICEM tests of cost-effectiveness. Respondents should use ER7 assumptions for the fixed charges associated with these purchases. Alternative assumptions on cost and availability may be considered for the Phase 1B sensitivities.

30. Consistent with Exh. 37, in removing spot capacity purchases from the barebones resource plan, the firm energy associated with these purchases should be redesignated to nonfirm for the base case scenario.

31. For their Phase 1B base case filings, respondents should include in the barebones resource plan the levels of uncommitted DSM adopted in ER7. Alternative levels of cost-effective uncommitted DSM may be considered as part of the Phase 1B sensitivities.

32. Consistent with the DRA/SDG&E Joint Exhibit on Resource Plan, filled in A.87-12-003, in Phase 1B SDG&E should test a number of uncommitted DSM programs using the ICEM approach adopted in A.82-04-44 et al., and clarified in this order.

33. SCE's Castaic/LADWP exchange agreement should be considered committed and included in SCE's Phase 1B barebones resource plan.

34. Rancho Seco should be excluded from SCE's and PG&E's barebones resource plans in Phase 1B, consistent with CEC's September 1, 1989 recommended changes to the ER7 data set.

35. For the Phase 1B barebones plan, PG&E should include the additional 62 MW of geothermal resources inadvertently omitted from

the ER7 data set, but only to the extent that these additions do not include future QF/self-generation additions after 1991.

36. For Phase 1B, SCE should include the Chino Battery storage project in the barebones resource plan during the project's demonstration phase. Beyond the demonstration phase, SCE should exclude the project from the resource plan, subject to a showing of cost-effectiveness and nondeferrability.

37. For Phase 1B, SCE should include the Axis steam plant and CT resources in its barebones resource plan, and incorporate Blythe loads into its demand forecast.

38. For the Phase 1B base case, SDG&E should adjust the ER7 committed DSM amounts by the figures presented in Exh. 24.

39. In Phase 1B, any party claiming that a baseload or intermediate load supply-side resource is nondeferrable must make the requisite four-part showing adopted in D.86-07-004, including a showing of cost-effectiveness.

40. In showing resource cost-effectiveness, the ICEM approach adopted in this order should be used wherever possible.

41. In the ICEM analysis of resource options, the cost of energy from variable-priced QFs should be set equal to the utility system's marginal costs (QF-in).

42. The age-deration approach agreed upon by respondents, CEC, DRA, and IEP/IPC is reasonable and should be adopted for this BRPU cycle.

43. Consistent with our ECAC determinations, short-term reserves should be considered available for production cost purposes over the entire forecast period. However, short-term reserves should count towards reserve margins and ERIs only if the total level of standby units is greater than the ER7 adopted age-deration levels. Otherwise, they should be excluded from reserve margin and ERI calculations in respondents' Phase 1B base case filings.

44. Consistent with our ECAC determinations, unless found to be cost-effective, long-term reserves should not be considered available for production costing purposes. Similarly, long-term reserves should also be excluded from ERI and reserve margin calculations as age-derated capacity.

45. Only life-extension investments, i.e., refurbishments or repowering, should qualify for the purpose of restoring age-derated capacity for ERI and reserve margin calculations.

46. If refurbishment or repowering of a standby unit is found to be cost-effective after the requisite investment is made, then only the amount of age-deration associated with that unit should be included as available capacity for ERI and reserve margin calculations.

47. For production costing purposes, short-term reserves should be assigned a penalty factor to properly reflect the expected limited dispatch of these units.

48. For their Phase 1B compliance filings, respondents should use the ELFIN "CM" designation, adding minimum capacity states for those units that are capable of shutting down at night and returning to service the following day to meet peak loads. This convention should apply to existing units as well as potential resource additions. For this purpose, respondents should use the modelling convention outlined in SCE's Exh. 12.

49. The CEC's modelling convention for as-available QFs, as presented in the ER7 data set, should be used for all Phase 1B filings. For future updates, as-available QFs should be modelled in the manner adopted in the most recent ECAC proceedings.

50. For the Phase 1B filings, parties using a model that dispatches units based on variable O&M costs (e.g., ELFIN Version 1.7) should post-process variable O&M costs, by multiplying the kWh from each unit by the appropriate unit price.

51. For the Phase 1B base case, respondents' estimates of variable O&M costs filed with the CEC in CFM-7 should be used in

post-processing the variable O&M costs of a utility's operating units.

52. The ELFIN "COMMT" feature should be retained for this update cycle.

53. The modelling adjustments proposed by SCE and SDG&E, as described in Table 4 attached to this order, should be adopted for the purpose of this BRPU cycle.

54. The time-sequential approach to applying the ICEM tests of cost-effectiveness best meets our criteria of accuracy, comprehension, understanding of the methodology and practicality of implementation, and should be adopted.

55. In applying the ICEM, only one resource addition should be evaluated for cost-effectiveness in a given iteration.

56. PG&E's prescreening method, as presented in Exh. 2, should be used in Phase 1B and future update proceedings by any party choosing to screen resource options prior to commencing the ICEM analysis. No other criteria should be used.

57. In applying the first-year test of cost-effectiveness, the ramped fixed cost streams for each option should be constructed using the single lifetime approach, with only real escalation contained in the fixed cost stream.

58. All supply-side resources considered in the ICEM analysis should be subjected to the first-year test of cost-effectiveness.

59. For its Phase 1B DSM filing, SDG&E should subject the DSM programs to both the first-year and life-cycle tests of cost-effectiveness. For application of the first year test, SDG&E should ramp the fixed costs of DSM programs.

60. Potential resource additions should be included in the resource plan only if they pass the first-year test during the first 12 years of the FS04 planning horizon.

61. For Phase 1B, potential resource additions should be included in the resource plan only if they pass the first-year test during the 1990-2001 period.

62. For the Phase 1B resource plan filings, a utility-built resource should be added in the first year that the resource becomes cost-effective, regardless of construction lead-time.

63. In conducting the ICEM analysis, a resource should be considered cost-effective over its lifetime if the NPV of the change in total costs (i.e., fixed costs of the option plus changes in production and shortage costs) is positive over the resource life. Relative cost-effectiveness should be determined by dividing the NPV of total life-cycle benefits by the NPV of total life-cycle costs of the option.

64. For this update cycle, parties should use the ER7 data sets through 2007 and then extrapolate production cost savings through each option's lifetime using general inflation.

65. Only technologies that are currently commercially available, or that are likely to become commercially viable during the 12-year planning period should be considered as potential resource additions. The burden of proof should be placed on respondents to demonstrate that a currently noncommercial technology is likely to be commercially available during that period.

66. For the Phase 1B base case analysis, respondents should use the CEC's illustrative loads for 1989-1991, but explicitly compare this approach with trending, making adjustments along the lines described in SF/U/F's testimony (Exh. 46).

67. Only the commodity costs of gas should be used for production cost model dispatch decisions.

68. Until we are able to develop long-run marginal gas costs, the full average cost of gas, including transportation-related gas costs, should be used in determining the cost-effectiveness of resource additions.

69. For the Phase 1B base case, respondents should substitute the dispatch gas costs they developed for their Phase 1A compliance filings for the gas costs contained in the ER7 data set.

70. In conducting their ICEM analyses, respondents should test the cost-effectiveness of baseload and intermediate load resources, in addition to resources with no ERCCs, for each year of the planning horizon.

71. A cost-effective resource addition that does not have any ERCCs should not form the basis of FSO4, i.e., it should be treated as a nondeferrable peaker.

72. For purposes of the ICEM analysis, a CT should be considered cost-effective in any year in which the ERI is 1.0 or greater.

73. In conducting the ICEM analysis, respondents should rely less on generic cost data, and more on data reflecting the specific circumstances particular to the resource being proposed.

74. All the costs of a candidate resource option should be included in the ICEM analysis, including land, regulatory approval and permitting, engineering and transmission costs, costs of interconnecting with the gas system for resources which use gas, and any other ancillary costs of adding that resource.

75. With the exception of the Heber geothermal return-to-service option, the resource types and costs presented by respondents in Exh. 50 should be used for the Phase 1B base case.

76. For future updates, parties presenting resource cost and financial assumptions should use the consistent format developed for Exh. 50 in this proceeding.

77. SDG&E's Heber geothermal return-to-service option should be deleted from consideration as a candidate resource addition for this update cycle.

78. Consistent with our determinations in D.87-11-024, in other proceedings where respondents develop resource cost estimates, they should justify any deviations from the cost estimates they have presented in this proceeding.

79. For the Phase 1B base case, respondents should use the financial assumptions they presented in Exh. 50, except that (1) an

average inflation rate of 5.0% should be used for the entire planning period, and (2) no real capital cost escalation should be assumed.

80. The issue of SO2 reinstatement should be addressed during Phase 1B. We should consider proposals for incorporating environmental considerations into the SO2 solicitation, as a test case, assuming that SO2 is reinstated for one or more utilities.

81. The issue of how to enable QFs to compete against power purchase opportunities that arise in between BRPU updates should be addressed during Phase 1B.

82. In Phase 1B, SDG&E should test a number of uncommitted DSM load management and efficiency programs using the ICEM approach adopted for supply-side additions in today's order. In evaluating program cost-effectiveness, SDG&E should consider all the costs of installing and operating the efficiency improvements, including participant costs.

83. In order to proceed expeditiously with Phase 1B, this order should be made effective today.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company (SCE), and San Diego Gas & Electric Company, collectively respondents, shall file a Phase 1B base case analysis to conform to the policies and resolution of issues set forth in Sections III. through VIII. of today's decision. The Phase 1B base case filing shall include:

a. The respective utility's base case scenario of QF deferrable resources and year-by-year projections of long-run avoided costs, together with supporting and explanatory materials;

b. A clear description of all resources considered to be nondeferrable, together with the requisite showings;

c. A list of all potential additions included in the iterative cost-effectiveness method (ICEM) prescreening and the additions subsequently considered in the ICEM analysis as a result of that screening;

d. A description of any year(s) in which the target reserve margins are not met or exceeded;

e. A description of any year(s) in which a combustion turbine would not have passed the ICEM analysis when the Energy Reliability Index is one or greater;

f. A comparison between trending and using the California Energy Commission's illustrative loads for connecting short-run and long-run demand forecasts;

g. Information on short-term and long-term reserves, as described in Section IV.C. of this decision;

h. Variable operation and maintenance estimates used for post-processing, including a clear explanation of their derivation and source; and

i. A list of all units assumed to be capable of cycling on a daily basis.

The Phase 1B base case analysis shall be filed and served no later than twenty (20) days from the effective date of this order. Respondents should deliver these filings on an expedited (i.e., overnight) basis to the key parties identified in Section VIII.E. of this decision, and include in that delivery copies of all workpapers and ELFIN input and output files (on hard copy and diskette).

2. Within ten (10) days from the effective date of this order, SCE shall file and serve a statement describing the status

of its contract with Kerr-McGee Chemical Corporation by the Argus Cogeneration Expansion project, including the date of contract execution, the contract term, and whether the contract is a standard offer or negotiated contract.

3. As described in Sections VIII.C. and VIII.D. of this order, the Commission Advisory and Compliance Division shall conduct additional workshops, as needed, to facilitate the development of a consensus approach for (a) allowing qualifying facilities to compete with interutility power purchase opportunities that arise between updates, and (b) incorporating environmental considerations into a Standard Offer 2 (SO2) solicitation. Commission Advisory and Compliance Division shall mail workshop notices to all parties to this proceeding not less than 10 days prior to the date scheduled for each workshop.

4. Within thirty-five (35) days from the effective date of this order, written comments on respondents' Phase 1B base case filings shall be filed and served. The purpose of these comments is to identify any areas where respondents have not complied with the directives in today's decision.

5. Within forty (40) days from the effective date of this order, respondents and all interested parties shall file and serve pre-workshop comments on the types of sensitivity scenarios they recommend for Phase 1B, consistent with the approach described in Section VIII.A. of this decision.

6. Within fifty (50) days from the effective date of this order, respondents and interested parties shall file and serve their positions on (1) under what circumstances should SO2 be made available, (2) what megawatt limits should apply when it is available, and (3) how to address potential oversubscription problems. Respondents and interested parties shall specifically comment on the Commission proposal outlined in D.88-09-026 for regulating the availability of SO2. If consensus cannot be reached via informal workshops, respondents and interested parties shall

also file their positions on how to incorporate environmental considerations into the SO2 solicitation process, as a test case. Reply comments shall be filed and served no later than ten (10) days after the filing of initial positions.

7. Commencing on August 1, 1990, and until further order by this Commission, respondents shall file and serve quarterly reports on the quantity, price, and terms of any spot firm capacity purchases made during the previous quarter. These reports shall be filed on February 1, May 1, August 1, and November 1 of each year. Two copies of each quarterly report shall also be mailed to the Commission Advisory and Commission Branch, Energy Branch.

8. Unless otherwise directed in this order, all filings shall be filed as compliance filings at the Commission's Docket Office. All filings and notices shall be served on all appearances and the state service list in this proceeding.

9. The assigned Administrative Law Judge shall schedule a further prehearing conference as soon as possible after issuance of today's order to establish a procedural schedule for addressing the Phase 1B issues described in Section VIII.

This order is effective today.

Dated MAR 28 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

I will file a written concurring opinion.

/s/ FREDERICK R. DUDA
Commissioner

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

RB

Table 1

SUMMARY OF PENDING RESOURCES

(Table Reproduced from Final ER-7)

	Dependable Capacity, MW			Available Energy, GWh		
	1992	1999	2007	1992	1999	2007
CONTRACTS: APPROVAL PENDING, CONTINGENCIES	456	778	778	1666	3021	3021
Northwest	328	528	528	660	945	945
PG&E/Seattle Exchange	0	200	200	0	285	285
PG&E/Puget Sound Exchange	300	300	300	413	413	413
Bur-Glen/PGX Purchase/Exchange	28	28	28	247	247	247
Southwest	128	250	250	1006	2075	2075
Riverside/Deseret Ren.	0	45	45	0	394	394
Anaheim/Deseret Ren.	0	77	77	0	675	675
M-S-R San Juan #4 (COTP Contingent)	128	128	128	1006	1006	1006
California	0	0	0	0	0	0
Add/Extend Castaic Exchange (SCE)	200	0	0	0	0	0
Add/Extend Castaic Exchange (LADWP)	-200	0	0	0	0	0
SHORT-RUN JURISDICTIONAL: UNDER REVIEW	150	150	150	470	470	470
QF	150	150	150	470	470	470
SCE Luz SEGS IX & X	150	150	150	470	470	470
Utility	0	0	0	0	0	0
SHORT-RUN JURISDICTIONAL: ANTICIPATED	330	330	330	1810	1810	1810
QF	230	230	230	1110	1110	1110
SCE Luz SEGS XI & XII	150	150	150	470	470	470
SCE Harbor/Chaplin	80	80	80	640	640	640
Utility	100	100	100	700	700	700
SCE Cool Water Gas Conversion	100	100	100	700	700	700
NORTHWEST PURCHASES OVER MUNI COTP	601	740	751	4221	5036	5014
Firm - Specific	92	139	150	438	657	657
Redding - BPA MOU	14	20	20	66	95	95
Santa Clara - BPA MOU	32	49	69	153	232	232
MID - BPA MOU	46	69	69	219	329	329
Firm - Generic Peaking	509	601	601	1404	1664	1665
SMUD	135	184	191	381	519	540
Small Nor Cal Munis	213	280	294	604	789	828
Azusa/Banning	10	9	9	25	21	18
SCE Resale Cities	151	128	107	394	335	279
Nonfirm	--	--	--	2379	2715	2692
SMUD	--	--	--	560	688	705
Small Nor Cal Munis	--	--	--	1272	1560	1601
Azusa/Banning	--	--	--	33	28	23
SCE Resale Cities	--	--	--	514	439	363
OTHER	144	457	457	1121	2840	2840
SCE Kerr McGee ACE Demonstration	92	92	92	706	706	706
SDG&E South Bay Unit 3 (CT Augment)	0	110	110	0	861	861
SDG&E Peaking (PGE Storage)	0	47	47	0	0	0
SDG&E CT Inlet Air Coolers	0	30	30	0	232	232
SDG&E New SO #2	52	178	178	415	1041	1041
TOTAL PENDING RESOURCES	1681	2455	2466	9288	13177	13155

TABLE 2A

PG&E's Base Case Resource Plan for Phase 1A
Positions of the Parties*

	CEC	PG&E	DRA	SF/U/F	IEP/IPC
1. Existing & Committed					
° QF/Self-Gen Additions	Yes	Yes 1/	Yes	After No-1991	After No-1990
° All Other	Yes	Yes 1/	Yes	Yes	Yes
2. Pending					
a. IOU Contracts					
° PG&E/Seattle	No	Yes	No	No	No
° PG&E/Puget	No	Yes	No	No	No
b. QF Contracts	N/A	N/A	N/A	N/A	N/A
c. IOU Projects	N/A	N/A	N/A	N/A	N/A
d. Muni Resources					
° Bur-Glen/PGX Purchase/Exch.	Yes	Yes	Yes	No	No
° MSR/San Juan #4	Yes	Yes	Yes	No	No
° NW Purch. over COTP	Yes	Yes	Yes	No	No
e. Demonstration Projects	N/A	N/A	N/A	N/A	N/A
3. Nondeferrable					
a. Uncommitted DSM	Yes	Yes	Yes	No	Yes
b. Spot Firm Capacity	Yes	Yes	Yes	No	Yes

* The reference point for this table is the ER7 ELFIN data set, as modified by CEC's September 1, 1989 recommended changes to reflect the shutdown of Rancho Seco. Positions of the parties reflect the positions expressed in concurrent briefs.

Note: N/A = Not applicable

Yes = Include in the base case resource plan before commencing the ICEM tests of cost-effectiveness for new additions.

No = Exclude from the base case resource plan before commencing the ICEM tests of cost-effectiveness for new additions.

1/ PG&E adds 62 MW of QF geothermal.

TABLE 2B

SCE's Base Case Resource Plan for Phase 1A
Positions of the Parties*

	CEC	SCE	DRA	SF/U/F	IEP/IPC
1. Existing & Committed					
• QF/Self-Gen Additions	Yes	Yes	Yes	After No-1991	After No-1990
• All Other	Yes	Yes 1/	Yes	Yes	Yes
2. Pending					
a. IOU Contracts					
• SCE/LADWP Castaic	Yes	Yes 2/	Yes	No	No
b. QF Contracts					
• LUZ SEGS IX-XII	Yes	Yes	Yes	No	No
• Harbor/Chaplin	No	No	No	No	No
c. IOU Projects					
• Cool Water Gas Conv.	Yes	Yes	No	No	No
d. Muni Resources					
• Resale Cities SW Cont.	Yes	Yes	Yes	No	No
• NW Purch. over COTP	Yes	Yes	Yes	No	No
e. Demonstration					
• Kerr McGee ACE	Yes	Yes	Yes	No	No
3. Nondeferrable					
a. Uncommitted DSM	Yes	Yes	Yes	No	Yes
b. Spot Firm Capacity	Yes	Yes	Yes	No	Yes

* The reference point for this table is the ER7 ELFIN data set, as modified by CEC's September 1, 1989 recommended changes to reflect the shutdown of Rancho Seco. Positions of the parties reflect the positions expressed in concurrent briefs.

Note: N/A = Not applicable

Yes = Include in the base case resource plan before commencing the ICEM tests of cost-effectiveness for new additions.

No = Exclude from the base case resource plan before commencing the ICEM tests of cost-effectiveness for new additions.

1/ SCE recommends adding (1) the Chino Battery storage project, and (2) the Axis steam plant and combustion turbine resources (and incorporating Blythe load).

2/ SCE reclassifies this resource as committed.

TABLE 2C

SDG&E's Base Case Resource Plan for Phase 1A
Positions of the Parties*

	CEC	SDG&E	DRA	SF/U/F	IEP/IPC
1. Existing & Committed					
° QF/Self-Gen Additions 1/	Yes	Yes	Yes	After No-1991	After No-1990
° All Other 1/	Yes	Yes	Yes	Yes	Yes
2. Pending					
a. IOU Contracts					
° PGE Storage (Renewal Only) 2/	No	No	No	No	No
b. QF Contracts 3/					
° New SO #2 3/	Yes	Yes	Yes	Yes	No
c. IOU Projects					
° South Bay Augment	No	No	No	No	No
° CT Inlet Air Coolers Retrofit	No	No	No	No	No
3. Nondeferrable					
a. Uncommitted DSM	Yes	Yes	Yes	No	Yes
b. Spot Firm Capacity	Yes	Yes	Yes	No	Yes

* The reference point for this table is the ER7 ELFIN data set, as modified by CEC's September 1, 1989 recommended changes to reflect the shutdown of Rancho Seco. Positions of the parties reflect the positions expressed in concurrent briefs.

Note: N/A = Not applicable

Yes = Include in the base case resource plan before commencing the ICEM tests of cost-effectiveness for new additions.

No = Exclude from the base case resource plan before commencing the ICEM tests of cost-effectiveness for new additions.

1/ SDG&E and DRA add capacity for DSM approved in the 1989 GRC decision.

2/ Existing contract is treated as "committed."

3/ During the course of the proceeding, CEC, DRA, SDG&E, and SF/U/F modified their position to remove 52.2 MW of QF projects that had dropped out of the SO2 solicitation.

TABLE 3

Phase 1A Determinations on Barebones Resource Plan

	PG&E	SCE	SDG&E
1. Existing and Committed			
• QF/Self-Gen Additions	No-After 1991*	No-After 1991*	No-After 1991*
• Rancho Seco[1/]	No	No	N/A
• 62 MW Additional QF Geothermal[2/]	Yes	N/A	N/A
• Axis Steam/CT (Add Blythe Load)	N/A	Yes	N/A
• Castaic Exchange	N/A	Yes	N/A
• Chino Battery Storage	N/A	Yes Demo Phase[3/]	N/A
• Additional GRC DSM[4/]	N/A	N/A	Yes
2. Pending			
a. IOU Contracts[5/]			
• PG&E/Seattle[5/]	No	N/A	N/A
• PG&E/Puget[5/]	No	N/A	N/A
• PGE Storage (1998 Renewal)	N/A	N/A	No
b. QF Contracts			
• LUZ SEGS IX-XII	N/A	Yes-50% Success Rate	N/A
• Harbor/Chaplin	N/A	No	N/A
• New SO2's			
- O'Brian	N/A	N/A	No
- Freeport-McMoran	N/A	N/A	No
- Bonneville	N/A	N/A	Yes-50% Success Rate
- LUZ SEGS 13	N/A	N/A	Yes-50% Success Rate
c. IOU Projects			
• Cool Water Gas Conv.[5/]	N/A	No	N/A
• South Bay Augment[5/]	N/A	N/A	No
• CT Inlet Air Coolers Retrofit[5/]	N/A	N/A	No
d. Muni Resources			
• NW Purch. over COTP	Yes	Yes	N/A
• Bur-Glen/PGX Purchase/Exch.	Yes	N/A	N/A
• MSR/San Juan #4	Yes	N/A	N/A
• Resale Cities SW Cont.	N/A	Yes	N/A

* Except for projects with negotiated referrals.

✓

TABLE 3
Page 2 of 2

Phase 1A Determinations on Barebones Resource Plan

	PG&E	SCE	SDG&E
e. Demonstration Projects			
• Kerr McGee ACE	N/A	Yes Demo Phase 3/	N/A
3. Nondeferrable			
a. Uncommitted DSM 5/	Yes	Yes	Yes
b. Spot Firm Capacity 5/	No	No	No

Note: N/A = Not applicable

Yes = Include in the barebones resource plan.

No = Exclude from the barebones resource plan.

1/ Rancho Seco should be excluded consistent with the assumptions in CEC Recommended Changes in the ER7 ELFIN Data Sets to Reflect the Shutdown of Rancho Seco, filed September 1, 1989 in this proceeding.

2/ PG&E should add these resources only to the extent that they do not include future QF/self-generation additions after 1991.

3/ These resources should be included in the barebones plan during the demonstration phase only, and subjected to the ICEM analysis for the commercial phase. If the SCE contract between Kerr-McGee is fully executed for the ACE project beyond the demonstration phase, then this resource should be included at a projected 100% success rate. Otherwise, it should be treated as described above. (See Section III.D.2.d. of this order.)

4/ SDG&E should adjust committed DSM amounts by the figures presented in Exhibit 24.

5/ These resources may be subjected to the ICEM analysis. (See Sections III.D.2.c., d., and f. of this order.)

"Other" Modelling Changes to ER7 Data Set (By Utility)

Modelling Convention Change (Utility)	Description of Change	Reference
1. Time Periods (SCE)	Changed to SCE's current modelling time periods (weekdays, weeknights and weekends).	Exh. 12, p. IV-1
2. Oil/Gas Unit Minimum Loading (SCE)	Set all units except 480s and Ormond Beach 2 to AGC minimum instead of DO-5 minimum.	Exh. 12, p. IV-1
3. CDWR Exchange (SCE)	Used more flexible energy schedule selection.	Exh. 12, p. IV-2
4. PNW Economy Energy (SCE)	Availability and price in 3 blocks and 2 subperiods instead of a single block.	Exh. 12, p. IV-2
5. PSW Economy Energy (SCE)	Used Draft Final ER7 prices.	Exh. 12, p. IV-2
6. Elfin Modelling Convention (SCE)	Changed "cp" and "en" designations to limited energy.	Exh. 12, p. IV-2
7. ELFIN Version (SCE)	Used Elfin Version 1.71.	Exh. 12, p. IV-3
8. Cool Water Gas Prices (SCE)	Used PG&E gas price forecast.	Exh. 12, p. IV-3
9. Modelling QFs (SCE)	Modelled QF capacity as baseload.	Exh. 12, p. IV-3
10. PGE and APS Contract Prices (SDG&E)	Energy prices reestimated consistent with contract terms.	Exh. 18, p. 11
11. Losses in PGE Contract (SDG&E)	Capacity reduced to reflect off-system losses.	Exh. 18, pp. 13-14
12. Addition of "__ nu" Card (SDG&E)	Added to Kearny resources to reflect multi-units.	Exh. 18, p. 13

TABLE 4

"Other" Modelling Changes to ER7 Data Set (By Utility)

Modelling Convention Change (Utility)	Description of Change	Reference
13. Gas Turbine Non-Summer Ratings (SDG&E)	Ratings modified to reflect higher capability of gas turbines during cooler weather.	Exh. 18, p. 13
14. Load Shapes (SDG&E)	Replaced hourly load shape data with CEC-adopted forecast.	Exh. 18, p. 14
15. Distillate Oil Price (SDG&E)	Replaced expense gas prices with distillate for turbines with no gas supply.	Exh. 18, p. 13
16. "NCOMMT" (PG&E)1/	Used non-derated COMMT feature of ELFIN.	Exh. 2, pp. 33-34

1/ This modelling change is not approved in today's order.

TABLE 5

Sample Calculations for ICEM Tests

Alamitos 3
First Year Cost Effectiveness Test
(Based on Marginal Cost Priced QF Payments)
Production Costs and Results

Line No.	(18) Year	(19) Production Cost Add CTs m$	(20) Production Cost Add Resource m$	(21) Change In Cost Production m$	(22) Change In Cost Capacity m$	(23) Total Benefits m$	(24) Total Costs m$	(25) First Year Test Result
1.	1990	2534.69	2535.25	-0.56	0.00	-0.56	8.24	Fail
2.	1991	2706.94	2707.88	-0.94	0.00	-0.94	8.65	Fail
3.	1992	3002.17	3002.39	-0.22	0.00	-0.22	9.08	Fail
4.	1993	3314.28	3316.53	-2.25	0.00	-2.25	9.54	Fail
5.	1994	3666.58	3667.20	-0.62	0.00	-0.62	10.01	Fail
6.	1995	4003.74	4002.81	0.93	1.26	2.19	10.51	Fail
7.	1996	4345.59	4342.92	2.67	12.07	14.74	11.04	Pass
8.	1997	4737.60	4734.26	3.34	26.57	29.91	11.59	Pass
9.	1998	4872.36	4865.06	7.30	31.60	38.90	12.17	Pass
10.	1999	5640.90	5632.77	8.13	33.18	41.31	12.78	Pass
11.	2000	6117.52	6104.03	13.49	34.84	48.33	13.42	Pass
12	2001	6844.57	6823.87	20.70	36.58	57.28	14.09	Pass
13	2002	7764.06	7729.85	34.21	38.41	72.62	14.79	Pass
14	2003	8689.23	8629.91	59.32	40.33	99.65	15.53	Pass
15	2004	9719.79	9603.50	116.29	42.35	158.64	16.31	Pass
16	2005	10969.09	10874.39	94.70	44.47	139.17	17.13	Pass
17.	2006	12212.95	12152.85	60.10	46.69	106.79	17.98	Pass
18.	2007	13619.73	13566.31	53.42	49.02	102.44	18.88	Pass
19.	2008			56.09	51.48	107.57	19.83	Pass
20.	2009			58.90	54.05	112.94	20.82	Pass
21.	2010			61.84	56.75	118.59	21.86	Pass
22.	2011			64.93	59.59	124.52	22.95	Pass
23.	2012	Escalated Benefits ------------>		68.18	62.57	130.75	24.10	Pass
24.	2013			71.59	65.70	137.28	25.30	Pass
25.	2014			75.17	68.98	144.15	26.57	Pass
26.	2015			78.93	72.43	151.36	27.90	Pass
27.	2016			82.87	76.05	158.92	29.29	Pass
28.	2017			87.02	79.86	166.87	30.76	Pass
29.	2018			91.37	83.85	175.21	32.29	Pass
30.	2019			95.93	88.04	183.97	33.91	Pass

Present Value of Benefits and Costs: 375.08 117.15

Benefit to Cost Ratio: 3.20

Source: SCE's Filing in Compliance with the January 2, 1990 Ruling of ALJ Gottstein, January 19, 1990, Table 3.

Overview of Resource Plan Determinations, By Resource Type

(1) Resource Type	(2) In Barebones Plan?	(3) Projected Success Rate	(4) Subject to ICEM Tests[1]	(5) Possible Phase 1B Sensitivities
IOU Project (Commercial)	Yes, if regulatory approvals obtained and construction started.	N/A	All projects not in barebones resource plan.	Alternative operating assumptions (e.g., capacity factor, maintenance rates) for committed projects. Alternative cost and operating assumptions for projects subject to ICEM.
Generic IOU Projects	Not included	N/A	N/A	Not included.
IOU Project (Demonstration)	For demonstration phase: Yes, if regulatory approvals obtained and construction started.	N/A	Projects in commercial operation (after demonstration phase).	Alternative operating assumptions for demonstration phase. Alternative cost and operating assumptions for commercial phase.
IOU Interutility Contracts	Yes, if contract executed.	Yes, accounting for regulatory uncertainty.	N/A for executed contracts; yes, for contracts under negotiation, if terms can reasonably be projected.[2]	Alternative success rates for executed contracts. Alternative terms/costs of contracts under negotiation if subjected to ICEM tests.[2]
QF Contracts	Yes, if contract (or (deferral agreement) executed or SO bid has been awarded.	Yes, accounting for regulatory and development uncertainties.[3]	N/A	Alternative success rates.
Self-generation (Existing/Committed)	Yes, if site exists or is under construction.	N/A	N/A	Alternative assessment of production/existing sites, etc.

FIGURE 1

Overview of Resource Plan Determinations, By Resource Type

(1) Resource Type	(2) In Barebones Plan?	(3) Projected Success Rate	(4) Subject to ICEM Tests	(5) Possible Phase 1B Sensitivities
Future QF Contracts and Self-Generation	Not included	N/A	N/A	Not included.
Muni Resources	Yes--all pending included.	N/A	N/A	None
Spot Capacity	Not Included	N/A	Yes	Alternative assumptions on cost and availability.
Uncommitted DSM	Yes, if determined to be cost-effective using Standard Practice Manual tests.	N/A	No 4/	Alternative assumptions on cost-effective levels.

Note: N/A = Not applicable

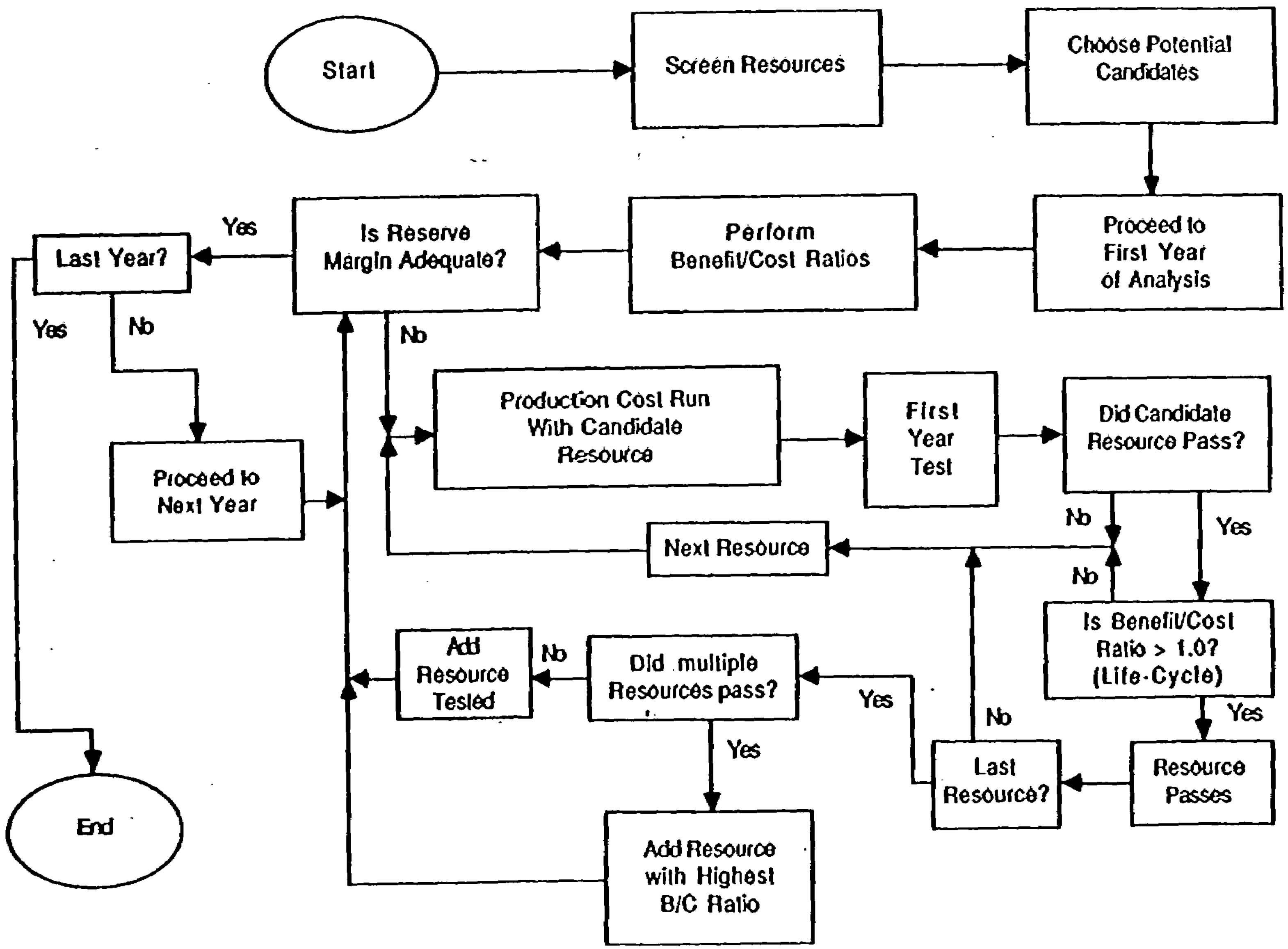
1/ Absent a showing of nondeferrability, all resources passing the ICEM tests of cost-effectiveness are deferrable by QFs.

2/ See Section III.D.2.c.

3/ For a winning bidder in an S02 or S04 solicitation, this success rate would account for the possibility that a developer does not choose to sign the contract, and pursue its project.

4/ Under our current methodology, cost-effective uncommitted DSM is included in the barebones plan, as a nondeferrable resource, based on the Standard Practice Manual tests. These programs are not currently subjected to the ICEM tests of cost-effectiveness. Our further consideration of how to integrate demand- and supply-side resources may alter this practice.

Time-Sequential ICEM



I.89-07-004 /ALJ/MEG/jt

FIGURE 2

ATTACHMENT 1
Page 1

Landmark CPUC Decisions on Avoided Cost, Standard Offers

The following list, although not exhaustive, shows where to find answers to the key questions that the Commission has addressed regarding QFs. The summaries are necessarily terse and are not intended either to indicate each issue in any given decision or to substitute for review of the actual text of the opinion and order. In addition to these decisions, our general rate case decisions have been used in the past to update certain standard offer terms. Finally, decisions in general rate case and fuel offset proceedings often contain analysis of marginal cost that is broadly relevant to QF policy.

I. Foundational Decisions

D.91109 - adopted "avoided cost" pricing for utility purchases from "private energy producers"

D.82-01-103 - guidelines for standard offers

D.82-04-071 - authorized "hydro savings prices" during spill conditions

D.85-07-022 - long-run avoided cost methodology

II. Decisions Implementing Variable Energy Payments and Standard Offers 1 2, and 3 (the Short-run Offers)

D.82-12-120	D.84-03-092	D.88-07-024
D.83-10-093	D.84-04-012	D.89-02-065

III. Decisions on Interim Standard Offer 4 (the Interim Long-run Offer)

D.83-09-054	D.85-04-075
D.83-12-050	D.85-06-163
D.84-08-035	D.85-07-121
D.84-10-098	D.86-10-038
D.85-01-040	D.86-12-013
D.85-02-069	D.86-12-104

IV. Show Cause Proceeding (PG&E)

D.84-03-093
D.84-08-031 - "good faith" guidelines for utilities in negotiating with QFs

V. Investigation of Transmission Constraints, Development of QF Milestone Procedure, and Administration of Transmission Priority

D.84-08-037	D.85-12-075	D.87-08-028
D.85-01-038	D.86-02-033	D.87-09-030
D.85-01-039	D.86-04-053	D.88-04-067
D.85-08-045	D.86-11-005	D.89-01-044
D.85-09-058	D.86-12-017	D.89-07-058
D.85-11-017	D.87-04-039	

VI. Standard Offer 2: Suspension and Reinstatement

D.86-03-069	D.87-09-025	D.89-02-017
D.86-05-024	D.87-11-024	D.89-07-022
D.86-11-071	D.87-12-056	D.89-08-031

VII. Development of the Resource Plan-based Offer (Final Standard Offer 4)

D.85-07-022	D.87-11-024	D.89-04-047 (Curtailment)
D.86-07-004	D.88-03-026	D.89-07-045
D.86-10-030	D.88-03-079	
D.87-05-060	D.88-09-026	

VIII. "Orphans," "Pioneers," and Nonstandard Contracts

D.93035	D.86-07-032	D.87-01-049
D.93364	D.86-08-017	D.87-03-068
D.82-04-087	D.86-09-040	D.87-05-065
D.82-07-021	D.86-10-039	D.87-07-086
D.83-05-043	D.86-10-044	D.87-08-047
D.83-05-047	D.86-12-018	D.87-09-074
D.83-06-109	D.86-12-061	D.87-09-080
D.84-05-057	D.86-12-062	D.87-10-038
D.86-03-030	D.86-12-098	D.87-11-063
D.86-06-060	D.86-12-100	D.88-03-036

IX. Energy Reliability Index (ERI) Capacity Valuation Methods

D.86-11-071	D.88-03-079	D.89-06-048

X. Out-of-Service Area QFs

D.88-04-070 D.88-09-067

XI. Avoidable Gas Costs

D.88-07-024 D.89-09-099

XII. Contract Administration

D.88-10-032 in R.88-06-007 (Guidelines)

(END OF ATTACHMENT 1)

ATTACHMENT 2
Page 1

Summary of Standard Offers[1/]

STANDARD OFFER 1: Variable Capacity and Energy

The QF's energy and capacity are sold on an as-available basis, meaning that the amount and time of delivery of the energy is not guaranteed. The QF is paid full short-run avoided energy cost, plus current shortage cost, on a per kilowatt-hour basis, for all energy delivered to the utility. Energy and shortage costs are updated quarterly and annually (respectively), with the energy cost based on the incremental energy rates established in the utility's last fuel offset proceeding and the expected fuel costs for that quarter. Shortage costs are based on the utility's cost of a combustion turbine. This contract is used by all technologies, but particularly wind, due to the uncertain nature of that resource.

STANDARD OFFER 2: Firm Capacity and Variable Energy

The QF's capacity is sold on a firm basis, meaning that an amount of capacity is guaranteed to be available to the utility during its peak load period. The capacity payments are based on levelized, forecasted shortage costs, which are stated in the contract and are fixed for the life of the contract. Energy prices are the same as in Standard Offer 1. Many cogenerators and biomass QFs hold Standard Offer 2 contracts.

STANDARD OFFER 3: Variable Capacity and Energy From QFs Not More Than 100 Kilowatts

This offer is the same as Standard Offer 1 in practice, but the contract terms and QF responsibilities are less involved, due to the small size of the facilities.

1/ Source: D.88-09-026 (in A.82-04-44 et al.), Appendix D.

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Page 2

INTERIM STANDARD OFFER 4: Long-term Capacity and Energy, Based on Forecast of Short-run Marginal Cost

This offer has fixed payment rates over long time spans (up to 10 years). There are three energy payment options and two capacity options.

Energy Option 1) Energy prices are fixed and are based on forecasted avoided energy costs. The QF can choose to have a mix of forecasted and current short-run avoided costs for the energy price, with oil & gas-fired cogenerators limited to 20% of the price being based on the forecasted prices.

Energy Option 2) This is similar to Option 1, except that the forecasted energy prices are levelized and oil & gas-fired cogenerators may not use this option at all.

Energy Option 3) Energy prices are based on fixed, forecasted utility incremental energy rates and utility oil & gas costs. Payments are made based on short-run costs, then adjusted at the end of the year to reflect the forecasted prices. This option is used by cogenerators and is designed to have the energy price reflect changes in fuel costs.

Capacity Option 1) As-available: The QF can choose payments based on either short-run shortage costs, or fixed, forecasted shortage costs, which are not levelized.

Capacity Option 2) Firm: Payments are based on fixed, forecasted, levelized shortage costs.

FINAL STANDARD OFFER 4: Long-term Capacity and Energy, Based on Avoidable Resource

See Attachment 3.

(END OF ATTACHMENT 2)

ATTACHMENT 3
Page 1

How Final Standard Offer 4 Works[1/]

Unlike the short-run standard offers and the interim long-run standard offer, final Standard Offer 4 derives from the respective utility's resource plan (including potential new plant construction, refurbishments, power purchases, etc.), as reviewed by the Commission in a biennial update proceeding. Pricing under final Standard Offer 4 varies according to when the QF comes on-line. During Period 2, the QF avoids a specific utility generation resource, and the QF receives payments based on the fixed and variable costs of the avoided resource. If the QF comes on-line in Period 1, i.e., before the date when the avoided resource would have begun delivery of electricity, the QF meets near-term demand growth, and therefore the QF receives short-run marginal cost-based payments until the start of Period 2. The Commission considers uncertainties and procurement strategies for each utility in determining a megawatt (MW) limit at each update proceeding. Whenever the capacity of QFs seeking final Standard Offer 4 contracts from a given utility exceeds that utility's MW limit, the available contracts are allocated through bidding. The utilities are also authorized to pay QFs additional sums for providing performance features (e.g., downward dispatchability at the utility's direction) not otherwise required under the standard offers.

We have adapted the following chronological overview from prior orders. We think the details of the final Standard Offer 4 resource planning process are more easily grasped with the total design in mind.

1/ Source: D.88-09-026 (in A.82-04-44 et al.), Appendix A.

ATTACHMENT 3
Page 2

The first step is the utility application. Following the latest Electricity Report of the California Energy Commission (CEC), the Pacific Gas and Electric Company, the San Diego Gas & Electric Company, and the Southern California Edison Company each file a resource plan with a 12-year planning horizon. The plan identifies within the horizon those potential resource additions that the applicant believes are cost-effective for its system. The plan states the costs associated with each such resource and the point in the planning horizon when that resource becomes cost-effective. The plan also states all relevant assumptions. The applicant presents its assumptions in internally consistent "scenarios." The latest CEC Electricity Report forecasts give the supply and demand assumptions for the base case scenario. The applicant may also file additional scenarios, or otherwise deal with the range of uncertainties underlying the forecasts, in order to explain the applicant's preferred procurement strategy.

The second step is hearings on the utility applications. The Commission's staff and other participants critique each resource plan. They may note internal inconsistencies in any of the applicants' scenarios, present alternative scenarios of their own, criticize the applicant's assessment of uncertainty, and challenge the reasonableness of an applicant's assumptions. They also check that the applicants have correctly implemented the Commission's cost-effectiveness methodology. Finally, these participants may explain their choice of the scenario best suited to the determination of avoidable plants.

The third step is Commission determination of avoidable plants for the respective utilities. Avoidable plants are essentially the cost-effective baseload or intermediate resource additions appearing in the first eight years of the resource plan that is preferred by the Commission. This choice is the key

Commission act in the long-run standard offer process. The Commission makes this choice according to the following criteria, among others: Are the plan and underlying assumptions plausible (i.e., internally consistent and reasonable, given known forecast uncertainties)? Does the plan expose ratepayers to unnecessary risks, either of premature commitments or of shortages? Is the plan consistent with energy regulatory goals and policies? The Commission decision comes about five months after filing of the applications.

The fourth step is the utilities' solicitation process and QF auction. After making any modifications ordered by the Commission, the utilities announce the availability of long-run standard offer contracts based on the capacity and the fixed and variable costs of the avoidable resource(s). QFs have a three-month solicitation period to respond. Each interested QF indicates (1) the resource that the QF seeks to avoid, (2) the QF's own technology and capacity, and (3) the QF's bid, which is the lowest percentage of the resource's fixed costs that the QF would be willing to accept. The bid cannot exceed the resource's fixed costs. The utility opens the responses at the end of the solicitation period. If QFs seeking to avoid a resource do not cumulatively exceed the resource's capacity, all these QFs are offered contracts at the full fixed costs of the resource. If such QFs do exceed the resource's capacity, contracts up to that MW limit are offered to the low-bidding QFs, and they receive that percentage of the resource's fixed costs bid by the lowest losing bidder. (This is known as a "second price" auction.) Contract signing occurs after the winning bidder complies with the prerequisites of the QF Milestone Procedure, roughly one year after the utility applications.

ATTACHMENT 3
Page 4

The <u>fifth step</u> is the update to the long-run standard offer. The update is scheduled every two years and follows each CEC Electricity Report. The utilities file new resource plans, and Steps 1 through 4 are repeated, with such modifications to the process as the parties may suggest and the Commission approves.

(END OF ATTACHMENT 3)

ATTACHMENT 4

MEG/btr

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

ADMINISTRATIVE LAW JUDGE'S RULING
ON SCOPE AND SCHEDULE FOR THE
STANDARD OFFER UPDATE PROCEEDING

I. Scope and Issues

On February 27, 1989, the Assigned Commissioner issued a ruling on a proposed schedule, scope and service list for Application 82-04-044 et al., the biennial Standard Offer Update Proceeding. The ruling established a three-phased approach for addressing the issues in this case:

"During Phase 1, we will focus on developing a resource plan-based SO4 [Standard Offer 4] using our current methodology. In Phase 2, we will address the issues related to SO2 [Standard Offer 2] availability, and update cost components that affect other offers. Proposals to change any of our standard offers will be considered in Phase 3." (Assigned Commissioner's Ruling, page 3.)

The Assigned Commissioner solicited written comments on the organization of issues, proposed schedule and Phase 1 workshops, as outlined in attachments to the ruling.[1] Comments were filed by the Division of Ratepayer Advocates (DRA), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), Independent Power Corporation (IPC), Santa Fe Geothermal, Inc., Unocal Corporation and Freeport-McMoRan Resource Partners (SF/U/F) and the California Energy Commission (CEC).

On April 7, 1989, I held a prehearing conference (PHC) to address procedural matters. At the start of the PHC, I presented an oral ruling in response to some of the issues raised in the written comments. My statements were intended to:

(1) Reaffirm the Assigned Commissioner's Ruling to implement during Phase 1 this Commission's adopted approach for establishing Standard Offer 4 (SO4) prices;

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1 Appendix B of the Assigned Commissioner's Ruling provided a more detailed description of the Phase 1 workshops and proposed issues to be addressed in each phase. Attachment C presented the proposed schedule adopted in Decision (D.) 88-09-026. Appendices B and C to this ruling revise and supersede the description of issues and Phase 1 schedule to reflect consideration of the written comments and the prehearing conference discussions.

(2) Clarify the role of the CEC's Seventh Electricity Report (ER7) "base case" resource plan scenario, and the extent to which alternative supply and demand assumptions would be considered in this proceeding;[2] and

(3) Clarify the scope of Phase 1 workshops and reaffirm the filing requirements outlined in the Assigned Commissioner's Ruling.

A copy of my PHC ruling is attached as Appendix A to this ruling, and incorporated herein. I have also revised the list of specific issues to be addressed in Phase 1 (by sub-phase 1A, 1B and 1C), in response to the written comments and PHC discussions. A description of those issues, by sub-phase, is attached as Appendix B. Attachment B also includes a description of the Phase 1A filing requirements and workshops, and a tentative list of issues for Phases 2 and 3.

As clarified in my PHC statements, the scope of Phase 1 is limited to "non merger" scenarios for SCE and SDG&E.[3] Actual S04 solicitation by either SCE or SDG&E will be deferred until the Commission has issued its decision in A.88-12-035. At that point, if the merger has been approved, we will reexamine resource needs for the combined company in this proceeding.

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2 The use of a common "base case" is integral to the Phase 1A modeling workshops and filing requirements. As I stated at the PHC, the use of CEC's ER7 demand and resource plan assumptions as our "base case" in this proceeding is contingent upon issuance of the Draft Final ER7 documents from Committee in the near future. (See Appendix A.)

3 The issues regarding the proposed merger between SCE and SDG&E are before this Commission in A.88-12-035. It would be duplicative to consider them in this proceeding as well. See PHC-10 transcript, page 329.

At the PHC, SDG&E asked how its recent agreements regarding demand-side management (DSM) would be integrated into this update.[4] I have since had an opportunity to review those agreements and applicable Commission decisions.

As I discussed at the PHC, in Phase 1B we will consider the range of uncertainty facing us in this update, and take account of strategic elements and contingencies (see Appendices A and B). In that phase, parties may present the results of alternative resource plan scenarios. However, I left it up to the parties to decide whether and how they would consider alternative assumptions on DSM.

Given the Commission's orders in D.88-12-085, I need to modify my directives. I will require SDG&E to include the results of an "integrated" DSM approach in its Phase 1B filings.[5]

In preparing this scenario, SDG&E shall use the resource plan assumptions/modeling conventions adopted in Phase 1A (except for uncommitted DSM). The choice of production cost model to perform Phase 1A and Phase 1B analysis, however, is left to SDG&E's discretion. A single production cost model should be used.[6]

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4 See PHC-10 transcript pp. 322-333. During the course of SDG&E's general rate case proceeding (A.87-12-003), DRA and SDG&E stipulated to testing a number of uncommitted DSM programs using the iterative cost effectiveness method (ICEM) adopted in this proceeding for supply-side additions. See D.88-12-085, finding of facts 97 and 98, conclusion of law 56, and interim ordering paragraph 11. See also the DRA/SDG&E Joint Exhibit On Resource Plan filed in A.87-12-003 (Exhibit 43), pp. 5-7.

5 This requirement applies only to SDG&E.

6 This does not preclude SDG&E from adding DSM "submodels" to feed into the production cost model used in Phase 1A. However, SDG&E should not introduce a "new" model for generating system operating costs in Phase 1B.

This analysis will provide useful information for Phase 1B and later phases of this proceeding. If the "integrated" approach does have a significant impact on deferrable resources for SDG&E, then we can consider those facts in our Phase 1B deliberations. Regardless of the results, SDG&E's efforts will enhance the value of the ongoing Standard Practice Manual workshops. This exercise will also provide the Commission and parties with "hands on" experience in preparation for the DSM issues in Phase 3.

II. Schedule for Phase 1A

The Phase 1A schedule discussed at the PHC is outlined in Appendix C. This schedule is based on each event taking place a certain number of weeks after the previous event has been completed. As soon as the CEC issues its final ER7, I will set Phase 1A hearing dates. A schedule for subsequent phases will be developed as we move further along with Phase 1A.

III. Pre-Phase 1A Workshops and Requests for Comments

As identified in the written comments and at the PHC, several issues deferred to this update lend themselves to informal resolution. At the PHC, I asked parties to prepare their positions in writing and conduct informal workshops to clarify and/or narrow the issues during the next several weeks.[7] To reiterate, parties are required to:

(1) File written comments no later than April 28, 1989 on the Commission's "floor-ceiling" proposal for PG&E's short-run

7 See PHC-10 Transcript pp. 330-333.

reliability adjustment, as discussed in D.88-03-079 (pages 16-18).[8]

(2) File written comments on the issue of whether or not the capacity factor assumed for the avoidable resource in final Standard Offer 4 should be updated. If updating is recommended, specific contract provisions should be proposed.[9]

(3) File written comments on the appropriate treatment of adders under PG&E's Interim Standard Offer 4, Curtailment Option B for Energy Payment Option 3 and Energy Payment Options 1 and 2 at the expiration of the fixed price period. Parties should comment both on the solution proposed by PG&E during the compliance hearings, and on the adaptability of final SO4 curtailment provisions to Interim SO4.[10]

For topics (2) and (3) above, I directed parties to file comments by May 5, 1989, and to hold workshops to address the various proposals. A written report summarizing the areas of agreement/remaining areas of disagreement on each of these issues should be filed no later than May 31, 1989.[11]

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8 In D.88-03-079, issued on September 16, 1988, the Commission directed parties to file comments on this issue. Although none have been filed to date, parties have apparently discussed the proposal informally and are prepared to comment at this time.

9 See D.88-03-079, pp. 40-41.

10 See D.88-09-026, pp. 49-52 for a discussion of this issue. On April 12, 1989, the Commission issued D.89-04-047 adopting the curtailment provisions for final SO4.

11 See PHC-10 Transcript pp. 330-333. I requested only written comments on topic (1). Workshops on this issue may be scheduled at a later date, once the parties' comments have been received and reviewed. For topic (2), I suggested at the PHC that SCE take the lead in coordinating the workshops. For topic (3), PG&E should be the coordinator.

Copies of all filings should be formally filed at the Commission's Docket Office and served on all persons under the "Appearances" and "State Service" categories of the Service List. As I mentioned at the PHC, I am requiring parties to deliver to me all filed documents on floppy diskettes or Bernoulli cartridges (in ASCII format), in addition to a printed copy.

Dated April 19, 1989, at San Francisco, California.

/s/ MEG S. GOTTSTEIN
Meg S. Gottstein
Administrative Law Judge

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ALJ's Prehearing Conference Ruling; April 7, 1989[1]

I'm here this morning to reaffirm the assigned Commissioner's ruling to implement during Phase 1 this Commission's adopted approach for establishing Standard Offer 4 prices. We've had a series of compliance decisions outlining this approach, culminating in Decision 88-09-026, which was issued just last fall, and, as most of you know, the Commission considered just about every permutation of cost-effectiveness methodology, of payment options, of bidding schemes and other implementation issues in making its determinations.

In Phase 1 we're going to implement that methodology, and I might add that the opportunity to have made your case for alternative approaches, to comment on the ALJ's draft decisions or to petition for rehearing is past and I do not intend to relitigate those issues during Phase 1.

Parties who are interested in proposing refinements or changes to the final Standard Offer 4 or any other final standard offer will be given the opportunity in Phase 3 as outlined in the assigned Commissioner's ruling.

My first priority is to implement this Commission's adopted final Standard Offer 4 methodology and complete Phase 1; however, there will be an opportunity during Phase 1 to continue informal discussions and possibly workshops on the issues that parties wish to address in later phases, and, further, I will leave open the option at the completion of Phase 1, after we have identified the deferrable resources for each utility, to broaden the scope of that phase to take into account some refinements that can aid this Commission in taking strategic elements and nonprice factors into account; however, at this point parties are directed to wait to file proposals for modifying our biddings' protocol or other aspects of our methodology until Phase 3.

Having said that unfortunately does not make the task facing us in Phase 1 any simpler. There are several more implementation issues even under our current Standard Offer 4 methodology that need to be resolved before we put out a bid for

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1 Transcript (PHC-10), pp. 307-317.

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Standard Offer 4, and, in addition to the ones identified in the February ruling, several of you identified additional ones that may be appropriate to include, and I'd be glad to give you my initial reaction to each of those today during our discussion.

In particular, having reviewed the comments, I am very receptive to the idea, as expressed by the DRA and the California Energy Commission, of quantifying a selected number of adders so that QFs can take them into account in developing their bid for the second price auction.

This adder system approach is one that was identified and encouraged by this Commission in its final compliance decision, and, as noted by that Commission, quantifying adders is a necessary first step in considering more elaborate bidding schemes such as multi-attribute bidding, so it is very appropriate and a good place to start.

The types of adders to consider will depend on the types of resources identified as deferrable by QFs, so I will consider DRA's suggestion to revise the schedule, allowing time for a Phase 1-C to consider an adder system once deferrable resources have been identified.

Let me turn to a couple of other important issues that were raised in the comments.

It's very clear from the comments that I need to say more with regard to the CEC base case.

First there's a question raised by Independent Power Corporation of what set of ER 7 resource plans or assumptions we're referring to given that ER 7 apparently developed several sets of supply and demand scenarios. And also very importantly I need to elaborate on the weight to be given the CEC base case and the degree to which alternative supply and demand assumptions will be considered.

In order to address those issues, I'm going to digress into a very--hopefully--brief description of our Standard Offer 4 methodology, and I think it's important to keep in mind what we're technically trying to achieve here in order to put these issues into perspective and to understand the scope of Phase 1.

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Our starting point for determining Standard Offer 4 prices is what we call the utility's bare-bones resource plan, it's existing and committed resources only, and we've defined those terms in our compliance decisions.

Taking that bare-bones resource plan with projections of demand and resource availabilities and prices, we generate a stream of system marginal costs--we refer to them as short-run costs because the resource plan is fixed--and that's a starting point. We then look at potential resource additions, compare them based on life-cycle and first-year costs and determine if they're cost effective.

It's an iterative process and it is much more complicated than I've just portrayed, but the basic elements are a bare-bones resource plan and a projection of that plan, the simulation of a system with a production cost model, and the projected costs of resource additions to be considered.

It's my understanding that the CEC ER 7 process takes a somewhat different approach, although a similar approach, in determining need for siting purposes.

Now, I am at somewhat of a disadvantage here because, as you're aware, the ER 7 report has not been finalized, although I did receive yesterday decision documents from the committee and these documents are clearly important elements of the committee's decision-making process. But for our purposes we need, at a minimum, the draft final--what they call the--Electric Supply Planning Assumptions Report--the ESPAR--which presents all the specific supply assumptions adopted by the committee.

Now, according to my understanding of--again, of the CEC process, subsequent to the draft final ESPAR and the Electricity Report coming out of committee, there will then be another round of hearings and subsequently a final report will be issued. That process may take six to eight weeks or even longer.

I'm not bringing up the time table for ER 7 to admonish the CEC in any way, because this Commission is painfully aware of how delays can occur in their deliberations, so I think OIR 2 is a perfect case in point. But what I'm about to say with regard to the role of the ER 7 CEC base case in this proceeding is contingent upon the emergence of a full draft final ER 7 report, the two reports I mentioned from committee, with a complete set of numbers to work with in the very near future. Because without such a document we cannot even begin the process of developing the base case data set which is integral to the modeling workshops into Phase 1-A.

If the draft final documents are issued shortly, then hopefully we can have a final CEC ER 7 sometime in June.

If, however, the ER 7 documents are delayed much longer, I may have to restructure Phase 1 and redefine the base case so that we can proceed expeditiously in developing final Standard Offer 4 prices.

But I am going to proceed under the assumption that the remaining documents, and particularly the ESPAR, will be issued very shortly, hopefully in a week or so.

And unless you hear otherwise from me in a subsequent ruling, what I'm about to say does represent the approach we're going to take in this proceeding with regard to the CEC base case.

As I stated before, the ER 7 planning process may use a slightly different approach in determining need for siting purposes than we do for establishing Standard Offer 4 prices.

Be that as it may, it's clear there's a common starting point for both approaches, and that's the bare bones resource plan I described earlier.

The bare bones resource plan is comprised of many supply and demand assumptions that have been litigated in ER 7. And ER 7 will make factual determinations on those assumptions. And I do not intend to create an ER 7 in this proceeding.

In other words, the supply and demand assumptions that go into whatever CEC scenario corresponds most closely to the bare bones resource plan will be given great weight.

And what I mean by that very specifically is that there are only three limited areas of supply and demand assumptions that I can envision would be subject to debate during Phase 1A.

The first is any inconsistencies in the CEC's definition of bare bones, relative to ours. I think that's relatively obvious and I would expect for parties to present a preferred bare bones scenario that would attempt to correct that inconsistency.

The second is any assumptions that were not addressed and resolved in the ER 7. And the CEC itself in its comments now identify some of those. And there may be more as the data set is developed.

The third relates to the cost estimates of potential resource additions.

There may be debate over what those potential resource additions are and what their actual costs would be.

Those are the three areas.

Any party expecting to develop preferred bare bones scenarios in Phase 1A using alternative assumptions in any other area is simply in the wrong proceeding.

They should have been and perhaps were in ER 7.

Now, this is not to say that alternative scenarios have no place in this proceeding.

This Commission discussed the appropriateness of using internally consistent alternative scenarios as a way of taking uncertainty into account in developing a final Standard Offer 4 solicitation.

There are other ways of taking uncertainty into account.

The Commission did not determine which is appropriate, but left it up to the parties to make proposals.

If any party desires to use alternative scenarios, either demand or supply assumptions, to make their presentation concerning the range of uncertainty facing us in this update, the appropriate place to do so is in Phase 1B, not Phase 1A.

I might add here that unlike the CEC in siting deliberations, this Commission cannot update final Standard Offer 4 prices every two years as it receives more current information about the supply and demand outlook.

We will be setting fixed contract prices for a 15-year term for possibly up to eight years in advance. And, therefore, the way we take uncertainty into account in Phase 1B may be different than the CEC does in their siting deliberations.

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I plan to modify the Phase 1 workshops and filing requirements description in Appendix B to clarify these points.

I'm sure there will be questions about what I've just said. And I am setting aside the whole day to discuss them.

Let me just move on to my final area of remarks.

Several parties raised objections to workshop requirements and filing requirements for Phase 1A.

The general theme running through those comments was that the workshops would take too long, they would detract from preparation for evidentiary hearings, and the final requirements require an inordinant amount of modeling work and analysis. And there were some comments implying that the requirements were unworkable.

I was also given assurances by some parties that, in fact, modeling conventions and modeling wouldn't be an issue in this case.

I'm skeptical--in fact, I'm somewhat amazed that anyone can predict at this juncture what the issues are going to be.

However, if the predictions are correct, and given the scope of Phase 1A, in terms of alternative assumptions that I just outlined, then, in fact, we should breeze right through Phase 1A.

However, I cannot personally predict which aspect of the process, the assumptions, the models or the modeling conventions will drive the differences among the parties conclusions.

And I need to know that explicitly prior to evidentiary hearings. And I need to establish a structure that will elicit those answers.

More specifically, I need to know whether it's differences in the definition of committed resources, subtle differences in the way that modelers characterize those resources in their production cost models, or differences in the models themselves that are driving the differences among the parties.

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And it is the responsibility of any party presenting modeling results as the basis of their testimony to sort through these issues and present the type of analysis outlined in the assigned Commissioner's ruling in their initial filings.

The workshop format, and not the hearing room, is the appropriate forum for parties to develop clarity in what the real issues are.

In short, I am not at all persuaded by any of the comments urging me to eliminate or reduce the filing requirements for the modeling workshops.

And the workshops and filing requirements that were outlined in the assigned Commissioner's ruling are consistent with the approach this Commission has taken over the last two years to implement its own directives and requirements of AB 475. Those requirements were discussed in the ruling and I won't go into them here.

But I will say that given the time constraint we're under in this proceeding and the fact we need to consider simulations for three utilities, it is even more imperative that the parties use the prehearing phase productively to identify key issues.

And I will address the scheduling issue and plan to accommodate those workshops in sufficient time to both prepare for the workshop and prepare for evidentiary hearings.

Again, we'll discuss the schedules later this afternoon.

That completes my ruling.

(END OF APPENDIX A)

I. Phase 1: Identifying SO4 Avoidable Resources

A. Scope/Issues

In Phase 1 we will define the MW limit and avoided costs for Standard Offer 4 (SO4), using the methodology and bidding procedures previously adopted by this Commission. Phase 1 will be divided into three "sub-phases":

(1) In Phase 1A, we will implement our Iterative Cost Effectiveness Method (ICEM) for identifying resources that are deferrable by QFs, using a single set of demand, supply, and resource cost assumptions.[1] In developing each utility's "bare bones" resource plan, parties will rely on the California Energy Commission's (CEC) adopted ER-7 supply and demand assumptions. Debate over resource assumptions during Phase 1A will be limited to the three specific areas outlined in the Administrative Law Judge's (ALJ) ruling at the April 7, 1989 Prehearing Conference (PHC).[2]

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1 The ICEM requires the utilities to prepare resource plans, using production cost models to select the most cost-effective additions. The product of this approach is a series of "identified deferrable resources" (IDRs), whose total capacity and costs define the maximum amount of capacity available for bid and the maximum prices winning QF bidders can receive. See D.86-07-004, pp. 83-85, and Public Staff Division's testimony in Phase II of the final SO4 proceeding (Exhibit 201, Chapter G and Appendix C).

2 Specifically, those areas are 1) any inconsistencies in the CEC's definition of "bare bones" (existing and committed resources), relative to this Commission's definition; 2) any assumptions that were not addressed and resolved in ER-7; and 3) the types and associated costs of potential resource additions (see Appendix A).

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The following issues deferred to this update will also be addressed during Phase 1A:[3]

(a) What method(s) to adopt for connecting short-run and long-run demand forecasts. (D.88-09-026, p. 19.)

(b) How to apply the new gas rate design in testing the cost-effectiveness of potential new resources, which serves to identify the avoidable resource. (D.88-07-024, pp. 19-20.)

(c) Whether or not the capacity factor assumed for the avoidable resource should be updated and, if so, how. (See D.88-03-079, pp. 40-41.)

(d) The appropriate treatment of adders under PG&E's <u>Interim</u> SO4, Curtailment Option B for Energy Payment Option 3, and for Energy Payment Options 1 and 2 at the expiration of the fixed price period (See D.88-09-026, pp. 49-52.)

At the conclusion of Phase 1A hearings, the ALJ will prepare a ruling or draft decision directing the parties to use a specific set of assumptions (including modeling conventions and costs of resource additions) in running their preferred models and

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3 As discussed at the PHC, and in this ruling, most of these issues will be addressed initially in informal workshops over the next several weeks. Parties are encouraged to present any negotiated resolution of these issues before the Commission prior to evidentiary hearings in Phase 1A. If necessary, however, time will be set aside to address these implementation issues during Phase 1A hearings.

conducting the ICEM.[4] A short workshop may be needed after this ruling/decision is issued to ensure that all parties interpret the directives consistently, and to answer any questions that may arise.

(2) In <u>Phase 1B</u>, we will address on the impacts of uncertainty and relevant strategic elements in developing a final SO4 solicitation.[5] Parties will present specific proposals for incorporating "contingency planning" into our consideration of the Phase 1A ICEM results. This may involve consideration of alternative scenarios to the CEC ER-7 base case (see Appendix A).[6] SDG&E is specifically required to include one scenario using the "integrated" approach to demand-side management (DSM) planning required by D.88-12-085.[7] At the completion of Phase 1B, the Commission will issue a decision determining the level of MWs available for bid under SO4.

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4 Again, any refinements to the CEC ER-7 Base Case resource plan assumptions would be limited to the three specific areas outlined in the ALJ's PHC ruling (see Appendix A).

5 We will also examine the results of Phase 1A model runs, and address any remaining significant differences in results due to the models themselves. All parties will be required to explain, as part of their Phase 1B filings, the differences between the ELFIN reference run and their preferred model run (see Section B, below). If none of the parties use the ELFIN reference model as their preferred model, we will direct DRA to perform a reference simulation for the Phase 1B hearings.

6 For a discussion of "probabilistic" planning and other related issues, see D.86-11-071, pp. 17-19, D.87-05-060, pp. 40-45, and D.88-09-026, pp. 5-6.

7 See attached ruling.

(3) Assuming that QF deferrable resources are identified, we will proceed in Phase 1C to quantify a selected number of adders prior to soliciting bids.[8] In addition, we will address any residual issues relating to implementation of our S04 methodology. We may also need to reexamine the issue of deferrable resources for SCE and SDG&E, should the merger be approved.[9]

B. Structure of Phase 1A Workshops and Filing Requirements

The resource plan update issues in Phase 1 will require careful examination of production cost modeling inputs and results. Over the past several years, the Commission has been developing data requirements and procedures to enhance its understanding of these models.[10] In D.87-12-066, the Commission required all parties in future proceedings designated by A.82-04-44 et al. for developing marginal or avoided costs to submit a simulation using the "reference" model ELFIN (in addition to their preferred model). This requirement was implemented in SDG&E's and SCE's most recent Energy Cost Adjustment Clause (ECAC) proceedings where production cost models were used to project annual incremental energy

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8 See D.88-09-026, pp. 23-38.

9 See attached ruling.

10 Our Commission also has a legislative mandate to review and assess the models used in our proceedings (State Assembly Bill 475, (AB 475)). To implement AB 475, we have embarked on a multi-year project to integrate appropriate model access and evaluation procedures into our review of utility applications. See D.87-12-066, pp. 201-205 for a description of AB 475 and of modeling issues in general.

rates.[11] Similarly, in D.88-12-040, the parties to PG&E's most recent ECAC proceeding were instructed to file a common "base case" resource plan simulation through their preferred model.

The objective of these procedures is to enable the assigned ALJ and the Commission to fully understand which factors drive the differences in model results: differences in resource assumptions, in approaches to modeling various resources ("modeling conventions") or in the models themselves. To this end, Phase 1A filing requirements and workshops will be structured as follows:

<u>CEC Seventh Electricity Report Base Case Filings</u>:

(1) The CEC Seventh Electricity Report (ER-7) demand and supply forecasts will form the base case "bare bones" scenario for PG&E, SCE, and SDG&E.[12] The production cost model ELFIN (version 1.7) will be the "reference model."[13]

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11 See D.88-09-031, pp. 13-14, 21-24, and D.88-12-093, pp. 10-11, for a discussion of the workshop procedures and filing requirements employed in these ECAC proceedings.

12 As clarified in the ALJ's PHC Ruling (see Appendix A), the supply and demand assumptions for whichever ER-7 resource plan corresponds most closely to our definition of "bare bones" (committed and existing resources only) will be used as the base case.

13 The CEC currently plans to use ELFIN version 1.7 for the base case input files and simulation results. However, if the CEC decides to use a later version of ELFIN to present its ER-7 results, that later version will become the "reference model" in this proceeding. If other parties use a different version of ELFIN, they will be required to provide the information described in Sections (3) and (4) above, as part of their initial filings.

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(2) As soon as possible after the final draft ER-7 documents are issued, and again after final adoption of ER-7, CEC staff will provide to PG&E, SDG&E, SCE, and other interested parties upon request, the ELFIN input and output files for this CEC base case "bare bones" scenario, through the reference model, ELFIN. This provides us with a single, "reference model base case" to establish system marginal costs for each utility, and to conduct the ICEM.

Utility Filings:

(3) As part of their initial resource plan filings, PG&E, SCE, and SDG&E will provide the input/output files and simulation results of the CEC base case scenario on their preferred model. Utility filings will include:

(a) A complete description of their implementation of the ICEM.

(b) A description of all potential resource additions considered, and their life-cycle and first-year costs.

(c) The results of the ICEM, using the CEC base case scenario, including the type, size, and assumed on-line date of all identified deferrable resources (IDRs.)

The filings shall include a description of the factors (e.g., model features) driving any differences in results, and a hierarchy of those impacts.[14] This provides us with a "preferred model base case" run which allows us to assess, at least on a preliminary basis, the impacts that model differences have on model results.[15]

(4) As part of the initial resource plan filings, PG&E, SCE, and SDG&E will provide the input/output files and simulation results of their preferred bare bones resource plan assumptions and modeling conventions using their preferred model. Proposals to modify the CEC base case assumptions are limited to the three categories discussed in the ALJ's PHC ruling (see Appendix A). This provides us with a "preferred model preferred scenario" run which enables us to assess the impacts that differences in resource assumptions and modeling conventions have on model results. Each utility will provide the results of the ICEM analysis

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14 For example, if the ELFIN reference model does not take account of spinning reserves, and the preferred model does, the utility could perform a base case run on its preferred model "suppressing" the spinning reserves feature. A comparison of the two runs would indicate how much of a difference in results (in terms of the type, magnitude, and timing of cost-effective avoidable resources) is due to this model feature. Alternative approaches to explaining model differences are acceptable, as long as they clarify the relationships between model feature(s) and changes in model results, and quantify the relative importance of each difference.

15 As described below, this step will need to be repeated after the ALJ ruling (or Commission decision) on Phase 1A issues. However, it is necessary to provide these runs at the outset to determine whether or not the differences in models appear to "dwarf" the differences in resource plan assumptions/modeling conventions (or vice versa).

(e.g., type, size, and on-line date of IDRs), using the preferred model, preferred scenario simulations. These filings will include:

(a) Reasons for making changes in resource plan assumptions or modeling conventions, and how these changes are consistent with the ALJ's PHC ruling.

(b) A summary of the differences in modeling conventions used in the preferred scenario, relative to the base case, and the change in ICEM results that these differences make.[16]

(c) A summary of the differences in any resource assumptions, used in the preferred scenario, relative to the base case, and the changes in ICEM results that these differences make.

(d) A comparison of results, in terms of the type, size, and on-line date of IDRs, for each proposed change to the base case resource assumptions or modeling conventions, using the preferred model.

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16 For example, the base case might treat certain resources "deterministically" (e.g., by not letting the model dispatch them based on price and availability, but rather "shaving load" or treating them as "must run" to ensure their utilization), whereas these same resources may be dispatched under the preferred set of modeling conventions. The relative effect of this difference would be assessed by running the preferred scenario (except for the modeling treatment of these resources) on the preferred model, and assessing the difference in ICEM results due to this one change.

<u>Intervenor Testimony</u>:

Other parties using production cost models in this proceeding are also required to file the information outlined in Sections (3) and (4) above.

<u>Workshops</u>:

(5) Initial workshops at the CEC will be held after the Draft Final ER-7 ELFIN runs are distributed. The purpose of these workshops is to clarify the CEC's ER-7 (draft final) "bare bones" assumptions and modeling conventions prior to the utility filings.[17]

(6) The Commission Advisory and Compliance Division will hold a second set of workshops as soon after the utility filings as possible for the purpose of reviewing and discussing the computer runs and information described above. A major objective of these workshops will be to focus all parties' attention on the issues, as identified in the utilities' filings, that have the most significant impact on the differences in IDRs.

(7) At the conclusion of these workshops, the Commission Advisory and Compliance Division arbiter will summarize for the assigned ALJ the hierarchy of impacts due to any differences in 1) the definition of "bare bones," 2) the types and costs of potential resource additions,

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17 To insure all parties a full opportunity to participate in the CEC workshops, the CEC is directed to notice all parties on the service list to this proceeding, no less than ten working days in advance, of the time and location for the first workshop.

3) assumptions not addressed in ER-7, 4) modeling conventions, and 5) model features. If areas of agreement can be reached regarding resource assumptions or modeling conventions, they should also be summarized in writing by the arbiter.[18]

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18 The utilities will be given sufficient time to prepare revised resource plan filings, along the lines described above, should their preferred scenarios change as a result of agreements reached during the workshops. The workshop report should also outline any proposed changes to the Phase 1A schedule to reflect the need for longer (or shorter) time to prepare for evidentiary hearings.

II. Phase 2: Availability of Standard Offer 2 and Avoided Cost Updating

In D.88-09-026 and D.89-02-017 we directed parties to address issues relating to Standard Offer 2 (SO2) availability in this biennial update.[19] Specifically, we solicited comments on wide-ranging aspects of SO2 availability, including:

(1) Number of blocks (and block size) available for each utility.

(2) Availability linked to the "Energy Reliability Index" (ERI) threshold.

(3) Maximum contract length of SO2.

(4) Queue Management (first-come; auction?).

(5) Contract Provisions--revised milestone procedures; economic curtailment features; uniform contract language.

In addition, during Phase 2 we will update the following cost components for standards offers, as appropriate:[20]

(1) Cost of combustion turbine (SO1, 2, 3, and SO4, Period 1).

(2) Reliability adjustments to the cost of a combustion turbine (for SO2 and SO4).[21]

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19 See D.88-09-026, pp. 38-42; D.89-02-017, p. 25, Findings of Facts 9 and 11.

20 See D.88-03-026 (Table A): Standard Offer Updating.

21 In D.88-03-079, we directed SDG&E and SCE to adjust the SO2 and SO4 capacity cost of a combustion turbine using an ERI based on expected unserved energy. We directed PG&E to use a CEC-based Target Reserve Margin method. ERIs for the fixed capacity payments under SO2 and SO4 are updated in each biennial update proceeding. ERIs for SO1 and SO3 variable capacity payments are updated in our annual ECAC proceedings. (See D.88-03-079, pp. 6-8, p. 18.)

(3) Revisions of costing periods with regard to the addition of super off-peak periods. (D.88-03-026, p. 7.)

(4) Updating of capacity allocation factors.

III. Phase 3: Refinements/Changes to Standard Offers

The biennial update is also the forum for considering refinements and changes to all standard offer methodology or contract terms (for all offers). This phase of the proceeding will consider proposals for implementation in the biennial update following the CEC's Eighth Electricity Report and in future ECACs. Several issues for further consideration were raised in Commission decisions or in comments to the February 27, 1989 Assigned Commissioner's ruling, including:

- Quantification of Performance Features, and analysis of the potential for an SO4 offer based on "disaggregated" resource needs.[22]

- Changes in capacity valuation methods to reflect any developments in the reliability modeling area. (See D.88-09-026, p. 21.) This includes consideration of a final short-run capacity adjustment method for PG&E. (See D.88-03-079, p. 16 and

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22 An SO4 offer based on disaggregated resource needs would provide "basic" energy and capacity prices set at long-run marginal costs, with enhancements that would enable us to take other factors into account in our QF procurement process:

> "Whether this enhancement of the process takes the form of multi-attribute bidding, RFP-type solicitation...or adders/subtractors to a contract base price, we would need to establish in advance at least the relative worth of each factor. Performance features seem to be the logical place to begin this analysis, both because of the utility operational concerns mentioned above and because there seem to be objective bases for pricing these features." (D.88-09-026, p. 36, emphasis added.)

We explicitly requested that utilities file revised reports on performance features in this update. (See D.88-09-026, p. 38.)

D.88-11-052, pp. 28-29.), and any changes to the long-run capacity adjustment methods adopted in D.88-03-079.

- How to determine the cost-effectiveness of DSM for inclusion in the adopted demand cost forecast. (See D.87-11-024, pp. 17-21.)[23]

- Consideration of an integrated methodology for all resource options (both generation and nongeneration. (See D.88-09-026, p. 22.)[24]

- Changes in avoidable gas costs after we have completed our analysis of marginal cost studies in the gas proceedings.[25]

- Consideration of line loss impact/methodology for QF avoidance of identifiable resource (D.88-09-026, pp. 44-48) for SO4 only.

- Consideration of changes to the current process of forecasting (incremental energy rates (IERs) in ECAC proceedings, including the use of "recorded" IERs.

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23 As discussed in this ruling, alternative levels of cost-effective DSM, as part of alternative scenarios to illustrate "strategic planning" or "uncertainty" considerations, can be presented as part of Phase 1B testimony. (See PHC transcript, pp. 323-324.)

24 As directed in this ruling, SDG&E will present the results of an "integrated" methodology in Phase 1B of this proceeding.

25 D.88-12-086 extends the time to file these studies until the end of May 1989 with comments due June 30, 1989. (See D.88-07-024, pp. 8, 21.)

(END OF APPENDIX B)

APPENDIX C

Phase 1A
Schedule of Events

Event	Week
Draft Final CEC ER7 Issued	-8
Draft Final ER7 Data Set Distributed; CEC Workshops Scheduled	-4
Final CEC ER7 Issued	0*
Final ER7 Data Set Distributed	3
Utilities File Phase 1A Testimony	10
Phase 1A Workshops Begin	12
CACD Files Workshop Report	16
Intervenors File Testimony	20
Utilities File Revised Testimony/Rebuttal	23
Phase 1A Hearings Begin (2 weeks)**	25

To be scheduled later: concurrent briefs, schedule for Phase 1A ruling/decision; workshops on Phase 1B issues.

* During weeks -8 to 0 parties will also file comments and workshop reports on the "pre phase 1" issues discussed in this ruling.

** As discussed at the PHC, evidentiary hearings will be scheduled for 10:00 a.m. to 4:00 p.m. on Monday, and 9:00 a.m. to 1:00 p.m., Tuesday through Friday.

(END OF APPENDIX C)

(END OF ATTACHMENT 4)

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Appearances

Respondents: John T. Guardalabene, Attorney at Law, for Pacific Gas and Electric Company; Julie Miller, Attorney at Law, for Southern California Edison Company; and Wayne Sakarias, Attorney at Law, for San Diego Gas & Electric Company.

Interested Parties: James D. Squeri, Attorney at Law, for Armour, St. John, Wilcox, Goodin & Schlotz; Nancy Thompson, for Barakat, Howard & Chamberlin; Barbara R. Barkovich, for Barkovich and Yap; C. Clark Leone, for Bonneville Power Administration; Neal A. Johnson, for California Waste Management Board; John Chandley, A. Kirk McKenzie, Attorneys at Law, Scott Matthews, Sanford Miller, and Paul Richins, for California Energy Commission; Reed V. Schmidt, for Bartle Wells Associates; C. Hayden Ames, for Chickering & Gregory; John D. Quinley, for Cogeneration Service Bureau; Randolph L. Wu, Attorney at Law, for El Paso Natural Gas Company; Kenneth R. Meyer, for Energy Consulting Group; Martin A. Mattes, Attorney at Law, for Graham & James; Barry Epstein and Dian Grueneich, for Law Offices of Dian M. Grueneich; David Branchcomb, for Henwood Energy Services, Inc.; Jan Smutney-Jones, for Independent Energy Producer Association; Thomas P. Corr, Attorney at Law, for Independent Energy Producers/Independent Power Corporation; William Marcus, for JBS Energy, Inc.; William Booth and Joseph Faber, Attorneys at Law, for Jackson, Tufts, Cole & Black; Norman A. Pedersen, Attorney at Law, for Jones, Day, Reavis & Pogue; Karen Edson, for KKE & Associates; Michael P. Alcantar, Attorney at Law, for Lindsay, Hart, Neil & Weigler; John Gulledge, for Los Angeles County Sanitation Districts; Michael Lotker, for LUZ International; Emilio E. Varanini, III, for Marron, Reid & Sheehy; Grant Nelson, for The Metropolitan Water District of Southern California; Joseph G. Meyer, for Joseph Meyer Associates; Jerry R. Bloom, Attorney at Law, for Morrison & Foerster; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates, Inc.; Ralph Cavanagh, Attorney at Law, for Natural Resources Defense Council; Ronald F. Helbling, for Nevada Electric Investment Company; Wallace Gibson, for Northwest Power Planning Council; Philip J. Di Virgilio, for PSE, Inc.; Donald W. Schoenbeck, for Regulatory & Cogeneration Services; Roberts and Kerner, by Douglas K. Kerner, Attorney at Law, for Santa Fe Geothermal, Unocal Corporation and Freeport-McMoran Resource Partners; Deborah L. Berger, Attorney at Law, for City of San Diego; Robert Weatherwax, for Sierra Energy & Risk Assessment, Inc.; Joyce Holtzclaw, for Sierra Pacific Resources; Kathi Robertson, for Simpson Paper Company; Steven Greenwald, Attorney at Law, and Glenn Berger, for Skadden, Arps,

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Appearances

Slate, Meagher & Flom; Roy Rawlings, for Southern California Gas Company; Ronald L. Knecht, for Spectrum Economics; Michel Peter Florio, Attorney at Law, for TURN; Michael J. Ruffatto, Attorney at Law, for Trigen Resources Corporation; Lori Govan, for U.S. Windpower, Inc.; Nancy Jo Albers, for Unocal; Law Offices of Matthew V. Brady, by Matthew V. Brady, Attorney at Law, for California Department of General Services; Donna Stone, for California Department of Water Resources; David L. Modisette, for Joint Committee on Energy Regulations and the Environment; John S. Castor, Tim Duane, Donald H. Maynor, Attorney at Law, and Donald G. Salow, for themselves.

Division of Ratepayer Advocates: Ida Passamonti, Attorney at Law.

(END OF ATTACHMENT 5)

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.

A.	Application (I.)
ACE	Argus Cogeneration Expansion (III.B.1.)
AFC	Application for Certification (III.B.1.)
ALJ	Administrative Law Judge (II.A.)
B/C	Benefit-Cost (V.D.)
BPA	Bonneville Power Administration (II.D.2.)
BRPU	Biennial Resource Plan Update (I.)
CEC	California Energy Commission (II.A.)
CM	ELFIN "Minimum Constrained" Commitment Designation (IV.D.)
CN	ELFIN "Nonfirm" Commitment Designation (IV.E.)
COL	Conclusion of Law (III.D.1.)
Collaborative	Statewide Collaborative Process (III.D.2.g.)
Conditional RETO	"Reasonably Expected to Occur" DSM Programs (III.D.1.)
Coolwater	Coolwater Coal Gasification Conversion (III.B.1.)
COTP	California-Oregon Transmission Project (III.B.1.)
CP	ELFIN "Quick-Start" Commitment Designation (IV.D.)
CSC	Cogenerators of Southern California (II.D.2.)
CT	Combustion Turbine (II.E.)
D.	Decision (II.A.)
DRA	Division of Ratepayer Advocates (II.D.2.)
DSM	Demand-side Management (III.C.)
ECAC	Energy Cost Adjustment Clause (III.D.2.d.)
ERCC	Energy-Related Capital Costs (VI.C.)

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ERI	Energy Reliability Index (II.E.)
ER6	1986 Electricity Report (II.D.1.)
ER7	Seventh Electricity Report (II.C.)
EUE	Expected Unserved Energy (VI.D.)
Exh.	Exhibit (II.D.2.)
FERC	Federal Energy Regulatory Commission (III.D.2.c.)
FOF	Finding of Fact (II.E.)
FSO4	Final Standard Offer 4 (II.A.)
GRC	General Rate Case (III.C.)
GRP	Generation Resource Plan (II.D.1.)
gWh	Gigawatt Hour (III.C.)
ICEM	Iterative Cost-Effectiveness Method (II.C.)
IDR	Identified Deferrable Resources (IV.A.1.)
IEP/IPC	Independent Energy Producers/Independent Power Corporation (II.D.2.)
IER	Incremental Energy Rate (IV.A.)
IOUs	Investor-Owned Utilities (I.)
ISTIGs	Intercooled Steam Injected Gas Turbines (V.E.)
LADWP	Los Angeles Department of Water and Power (III.B.1.)
LRACs	Long-Run Avoided Costs (II.B.)
MOUs	Memorandums of Understanding (III.B.1.)
MSR	Modesto-Santa Clara-Redding (III.B.1.)
Muni	Municipal (III.B.1.)
MWs	Megawatts (II.A.)
NPV	Net Present Value (V.D.)
OII	Order Instituting Investigation (II.D.2.)
O&M	Operation and Maintenance (IV.)
PG&E	Pacific Gas and Electric Company (II.D.2.)
PGE	Portland General Electric (III.B.1.)
PGX	Portland General Exchange (III.B.1.)
PHC	Prehearing Conference (II.D.2.)
PNW	Pacific Northwest (III.C.)

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PURPA	Public Utility Regulatory Policies Act (II.A.)
QFs	Qualifying Facilities (II.A.)
SCE	Southern California Edison Company (II.D.2.)
SDG&E	San Diego Gas & Electric Company (II.D.2.)
SF/U/F	Santa Fe Geothermal, Unocal Corporation and Freeport-McMoran Resources Partners (II.D.2.)
SMUD	Sacramento Municipal Utility District (III.D.2.h.)
SO1	Standard Offer 1 (II.A.)
SO2	Standard Offer 2 (II.A.)
SO3	Standard Offer 3 (II.A.)
SRACs	Short-Run Avoided Costs (III.D.2.a.)
STIGs	Steam Injected Gas Turbines (V.E.)
TR	Reporter's Transcript (III.)
UEG	Utility Electric Generation (VI.B.)

(END OF ATTACHMENT 6)

FREDERICK R. DUDA, Commissioner, concurring.

Assigned Administrative Law Judge Gottstein has done an admirable job of resolving many of the technical issues presented in this proceeding. I believe, however, that there are important points to be made about the current and future direction of this proceeding that are not addressed in today's decision. In general, these points relate to the increasing needs of utilities and regulation to recognize and use the economic forces of competition. This is problematic because the issues in electric utility resource plan integration are difficult to resolve with the current policy and economic mechanisms we now use. In this proceeding, it appears that the parties have a number of new and quite refined tools and methods to resolve these difficult issues. My comments are directed primarily at the use of such tools, particularly regarding the timing and substance of the Commission's deliberations in three areas.

First, there is the issue of "apples-to-apples" comparisons between supply and demand-side resources. Today's decision stops short of discussing the comparative rate impacts of demand and supply options, leaving this major issue unresolved again. The point I make is that rate impacts caused by supply and demand-side projects are not explicitly a part of the ICEM at this time. While the Commission has grappled with this issue for at least the five years of my tenure, as yet there is no direction or proposal for resolution of this issue. One starting point is to look more carefully at the loss of load and customer base that will accompany an incremental increase in rates, given expected refinements in rate design and the use of negotiated sales contracts for large customers. At this juncture, it seems incumbent on the Commission, our utilities, and other interested parties to focus on development of an explicit methodology to address this problem, possibly through workshops. This seems especially important in light of major efforts to increase utility delivery of demand-side services and the collaborative process.

A related matter is the assumption that supply and demand-side projects can be directly compared on economic terms. As most are well aware, the Commission and the industry have made great efforts to establish grounds for comparison of demand and supply options (through use of the Standard Practice for cost-benefit analysis, etc.). And with more direct comparisons of demand and supply options the benefits and tradeoffs become more clear. Demand-management projects, however, provide somewhat different services in comparison to electricity delivered at particular voltages and frequency levels. Moreover, the value to customers of demand-side projects may be different than an "equivalent amount" of electricity (or gas) service. To my knowledge, this point has not been even scheduled for discussed, in the BRPU or other Commission proceedings, so that some resolve might come about. Moreover, the BRPU has not considered issues related to variations in customer service levels that result from voltage and frequency level changes, or the use of increased comfort via demand-side programs. In short, at some point the Commission needs to address these differences in customer service levels and customers' value of service. Traditional cost-effectiveness approaches and the ICEM appear to fall short because they are based on marginal costs without regard for customers' marginal value of service. This is particularly important currently, because economic competition for the utility is based on its ability to adequately meet each customer's value of service.

Second, both economic criteria for reliability and the use of multi-attribute bidding should be addressed as soon as possible, and maybe before Phase I is completed. At this point these subjects are scheduled for Phase II or III of the BRPU for decision possibly in 1991 or more likely 1992. In prior based reliability criteria, and testimony was filed almost four years ago in response to the Commission's direction. The use of economic criteria for reliability were reviewed in this proceeding and discussed in November of 1986 (D. 86-11-071). At that time the Commission suggested further refinement and was encouraging in its support for this approach, but rejected the specific proposal as "too preliminary ... at this time." We still have not revisited this area. With respect to multi-attribute bidding, the benefits of this approach seem great, particularly because it can reflect tradeoffs between economic efficiency, facility location, and environmental goals.

The problems with waiting to resolve these issues are (1) that the basis for the entire ICEM approach may change substantially when an economic criteria for reliability is used, and (2) the ICEM approach as currently formulated may not work to define the appropriate basis for multi-attribute bidding. Thus, there is a current need to assess the use of the ICEM approach as the benchmark for long-run avoided cost pricing both in the context of economic reliability criteria and with respect to multi-attribute bidding.

Third, the ICEM essentially uses a set of scenarios to consider uncertainties in resource planning. The results of such an approach depend on the bundling of assumptions in each scenario, which can only be subjective. Accordingly, it is difficult to "map" the effects of the critical uncertainties in a systematic fashion. The scenario approach is somewhat simplistic, which can be an advantage, but its deployment in this proceeding will keep us from using more sophisticated approaches for treatment of uncertainty for some time. While we are aware of important new approaches to treat uncertainty in a systematic fashion, we as yet have not allowed such approaches to be presented in this proceeding. The uncertainties that surround the assumptions and results used for avoided costs are very large, and thus deserve sophisticated treatment.

I encourage the Commission to afford the opportunity for the interested parties to formally present these new tools in this proceeding as soon as possible.

Frederick R. Duda, Commissioner

March 28, 1990
San Francisco, California