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Decision 92-03-038 March 11, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Order Instituting Rulemaking on the Commission's own motion to establish rules and procedures governing utility demand-side management.	R.91-08-003 (Filed August 7, 1991)
Order Instituting Investigation on the Commission's own motion to establish procedures governing demand-side management and the competitive procurement thereof.	I.91-08-002 (Filed August 7, 1991)

(See Attachment 2 for Appearances.)

I N D E X

I N D E X

INTERIM OPINION ON PACIFIC GAS AND ELECTRIC COMPANY'S BIDDING PILOT

1. Summary

By today's order, we begin the process of testing various forms of demand-side management (DSM) bidding and bid evaluation techniques, pursuant to Public Utilities Code § 747 and our recently adopted rules governing DSM.[1] This process begins with our approval of Pacific Gas & Electric Company's (PG&E) proposed DSM pilot bidding program, as modified by this order. PG&E's bidding pilot represents the first of several to be conducted by investor-owned utilities and evaluated by this Commission. As we recently stated in D.92-02-075, "these bidding experiments will help us learn more about alternative DSM delivery mechanisms, and assess the role of DSM bidding to provide least-cost DSM services to ratepayers."[2]

In view of the experimental nature of these initial pilots, we reduce the size of PG&E's proposed pilot program from 50 megawatts (MWs) to 20 MWs. In addition, we modify certain aspects of PG&E's bid evaluation criteria to make them more objective and transparent. PG&E is authorized to include expenditures for the 20 MW pilot bidding program in its existing balancing account for other PG&E resource DSM programs. For 1992 bid solicitation and contract negotiation expenses, PG&E is authorized to increase its revenue requirement by $500,000. To cover DSM pilot bidding expenditures for 1993-1995, PG&E is authorized to increase its revenue requirement by $17.5 million (in 1992 dollars). Beyond

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1 See Decision (D.) 92-02-075, mimeo. pp. 60-62; Attachment 1, Rules 26-29.

2 D.92-02-075, mimeo. p. 13.

1995, PG&E should request specific funding in the appropriate general rate case proceeding. Within 60 days from the effective date of this order, PG&E will file revised bid solicitation material, consistent with the modifications described in today's order.[3]

2. Background

On August 7, 1991, the Commission issued an Order Instituting Rulemaking and companion Investigation to establish rules and procedures governing DSM activities (DSM OIR/OII). One of the procedures discussed in the August 7 rulemaking was the competitive procurement of DSM programs, referred to generally as "DSM pilot bidding." The Commission directed utilities to develop and present pilot programs for consideration, consistent with the mandate of Public Utilities (PU) Code § 747.[4] For this purpose, the Commission endorsed the formation of a Bidding Advisory Committee, with representatives from utilities, consumer and environmental groups, energy service companies (ESCOs), and other interested parties. PG&E was directed to remove its DSM pilot bidding proposal from Application (A.) 91-04-003, and submit it for review in this investigation.

A prehearing conference was held on September 9, 1991 to address scheduling issues for the DSM pilot bidding programs. Since PG&E had already developed its proposal through an Advisory Committee process, and more time was needed for parties to confer

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3 Attachment 1 explains each technical acronym or other abbreviation that appears in this decision.

4 PU Code § 747 requires that one or more energy utilities implement pilot programs to test: (1) the ability of DSM bidding to deliver benefits to utility customers, separate from any generation resource bidding system; (2) the feasibility of an integrated bidding system that includes both generation resources and DSM programs; and (3) a program of competitive DSM bidding auctions for gas utilities.

on additional pilots, the assigned Administrative Law Judge (ALJ) decided to stagger the review, proceeding first with PG&E's pilot program. PG&E filed testimony describing its proposed pilot and funding request on September 13, 1991. Intervenor testimony was filed on October 2, 1991. PG&E filed rebuttal testimony on October 15, 1991. Evidentiary hearings were held from October 21 to October 28.

Opening Briefs were filed on November 12, 1991 by PG&E, Southern California Edison (SCE), the California Energy Commission (CEC), the Division of Ratepayer Advocates (DRA), the National Association of Energy Service Companies (NAESCO), SESCO, Inc. (SESCO), Transphase, Inc. (Transphase), and Energy & Resource Advocates, Inc. (ERA).[5] Reply briefs were filed on November 18, 1991 by PG&E, SCE, DRA, SESCO, and Transphase. By ruling dated January 16, 1992, the assigned ALJ set aside submission of this case to obtain cost estimates from PG&E for a pilot program that was smaller than PG&E originally proposed. This information was filed on January 31, 1992 (late-filed Exhibit (Ex.) 27). Transphase, ERA, and SESCO filed comments on the proposed reduction in pilot size and PG&E's supplemental filing. With the filing of these comments, PG&E's bidding pilot program was submitted on February 14, 1992.

By this interim order, we address only PG&E's DSM bidding pilot. Utilities will file proposals for additional pilot programs in 1992.

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5 SCE filed its opening brief one day late, and requests an extension of time. As SCE explains in its request, the brief was not filed by the close of business on November 12, 1991 because SCE's courier arrived too late at the Commission's Los Angeles office. SCE notes that it sent copies of its brief to the key parties via overnight mail, concurrent with the dispatch of the courier. Therefore, we find that no party was prejudiced by the one-day delay in filing, and grant SCE's request.

3. PG&E's Proposed Pilot

PG&E proposes a partnership bidding approach for its pilot program. Under a partnership bid, ESCOs compete for DSM programs that augment and enhance (rather than replace) existing or planned utility DSM activities. PG&E proposes to select up to 50 MW of DSM proposals from the solicited bids. PG&E requests that the Commission include the energy savings produced by this bidding pilot in the calculation of shareholder earnings incentives for 1992 and thereafter.[6]

PG&E estimates that the 50 MW bidding pilot will cost between $41 and $77.5 million in net present value (NPV) 1992 dollars over the 1992-2002 program period. These costs include contract payments, utility administrative costs, and shareholder earnings.[7] PG&E requests balancing account treatment for this program, with flexibility to reallocate funds among years in the 1993-1995 timeframe.

PG&E presents a completed Request For Proposals (RFP) for its bidding pilot in Ex. 4. In response to the RFP, ESCOs will submit proposals describing the kinds of energy efficient equipment they will install, the customer classes they will target, the kinds

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6 By D.90-08-068, the Commission established a shared-savings incentive mechanism for DSM activities that reduce utilities' energy and/or capacity needs. For PG&E, the shared- savings incentive is currently set at 15% of the net resource benefits (avoided energy and capacity costs, less administrative costs) produced by these programs. These incentive mechanisms were established for a limited period (e.g., through 1992 for PG&E), and are subject to review and modification as part of this DSM OIR/OII.

7 See Exhs. 19 and 25B. The minimum and maximum range of costs depend on various assumptions, including the price of the bid, the level and timing of savings, the level of PG&E's administrative costs, the degree to which bidders receive upfront payments, etc. (See Reporters' Transcript (TR), pp. 528-529.)

of measurement protocols they will use to demonstrate savings, and their bid price.

As described in Ex. 4, PG&E would begin its review with a screening process to ensure that each bidder has met certain eligibility requirements and minimum thresholds. These include:

- o Eligibility: The bidder cannot be a PG&E affiliate or subsidiary; resources that supply power, rather than produce savings (e.g., qualifying facilities) are not eligible to bid.

- o Market Coverage: Bids can be made in all sectors, but only for programs achieving savings through retrofit or replacement measures (e.g., not new construction programs).

- o Eligible Facilities: Measures must be installed in facilities located in PG&E's electric service territory.

- o Eligible Energy Efficiency: Electric and gas energy efficiency proposals, including load management, are eligible; proposals that include gas efficiency must also include an electric efficiency component. Bid measures and technologies must be documented as commercially available and proven.

- o Threshold Compatibility: Bidders must describe how their proposal is compatible with or complementary to existing and planned PG&E energy efficiency programs.

- o Threshold Cost-Effectiveness: Proposals must pass the Utility Cost (UC) test and the Total Resource Cost (TRC) test[8] with benefit-cost ratios of one or larger.

- o Fuel Substitution: Any fuel substitution component must pass the TRC test and produce

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8 See Section 4.3.1.1 below for a description of these tests.

a minimum of 20% energy savings during each calendar year.

- o Minimum Size Restriction: Each proposal must achieve a minimum of 100 kW in capacity savings or 100,000 kWh in energy savings.

- o Measurement and Verification Plan: Proposals must include a measurement and verification plan demonstrating that program savings will be measured and verified using a practical, feasible, reliable, and statistically valid methodology.

For all proposals that pass the screening process, PG&E would continue its evaluation based on the following list of weighted attributes:

o Economics	45%
o Measurement/Verification Plan	15%
o Bidder Qualifications	10%
o Marketing Plan	10%
o Compatibility With PG&E's DSM Programs	10%
o Comprehensiveness Of Package	7%
o Location	3%

In its RFP, PG&E stresses that the above weights are approximate, intended to give the bidder a general idea of the relative rankings, but not designed to develop a self-scoring system. PG&E intends to use the weights to rank the proposals initially, but reserves the right to alter the ranking based on PG&E's review of other factors relevant to the potential of the program. PG&E plans to evaluate some parts of the attributes quantitatively, and other parts qualitatively.

Based on its evaluation, PG&E would select a short list of proposals for negotiation. Ex. 6 presents a sample contract for the winning bidders. Negotiations could cover all aspects of the contract; however, bid price would be negotiable only in response to an alteration in some other aspect of the bid. Upon completion of a contract with PG&E to obtain the load reductions at an agreed-upon

cost per unit, the ESCOs (with assistance from PG&E) will be responsible for obtaining customer participation.

Payments to ESCOs would commence upon receipt of (1) verification of project completion, (2) acceptable estimates of claimed power savings and verification that the TRC benefit-cost ratio is greater than one, and (3) an acceptable description of an annual inspection/verification procedure. The maximum term of the contract, and associated payments, is seven years past the commencement date. Winning bidders are required to post program completion security of $15/kW capacity savings and provide acceptable liquidated damages in the event that the program performs at less than 85% of committed savings. Winning bidders would also be required to submit the results of measurement and verification activities performed, on an annual basis. Payments to winning bidders are based on the results of the verification efforts outlined in each bidders' measurement and verification plan.

PG&E estimates that the above process, from the issuance of the RFP through contract signing, will take 11 months.

4. Positions of the Parties

Written testimony was filed by PG&E, CEC, DRA, Transphase, SESCO, ERA, and the Natural Resources Defense Council (NRDC). SCE participated in cross-examination and submitted opening and reply briefs. NAESCO submitted an opening brief. Each party's position is summarized below, by issue.

4.1 Form of Bid

As part of their testimony on PG&E's pilot, parties addressed the issue of the appropriate form of bid, both in the short- and longer-term.

As PG&E describes it, the purpose of the partnership bid is "to test the feasibility and desirability of using DSM bidding to complement utility programs in delivering energy efficiency services to customers." (PG&E Brief, p. 1.) PG&E believes that it is preferable to gain experience with this form of bid, before

examining approaches designed to be supply-side equivalent bids (e.g., demand-side replacement or integrated bids). Moreover, PG&E argues that the partnership approach satisfies the requirements of PU Code § 747 and meets the Collaborative Blueprint objective of complementing existing DSM programs and objectives.[9]

SCE and CEC support PG&E's position. They urge the Commission to allow PG&E to explore this type of bidding relationship with ESCOs, as part of the overall pilot bidding program. In their view, the Commission's final determinations on the most desirable form of bid should await the outcome of the bidding experiments proposed pursuant to PU Code § 747.

Transphase, SESCO, NRDC, and ERA also support the basic form of PG&E's "positive partnership" approach to this pilot bid. They all stress the desirability of a cooperative approach to utility/ESCO relationships, at least for PG&E's initial experimental program. For example, Transphase argues that it is far easier for a winning bidder to successfully market the project with the aid and assistance of the utility, rather than having the utility as an adversary. (Transphase Brief, p. 3.) In ERA's view, competition between a single utility and individual energy providers (e.g., a replacement bid) would dramatically change the utility's attitude toward ESCOs. Instead of cooperatively providing information on their customers' consumption or billing history, or supporting the ESCOs in their efforts, utilities would undermine the program, in ERA's opinion. (Ex. 21, pp. 7-8.)

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9 On July 10, 1989, the Commission held an en banc hearing to reexamine the role of DSM in utility resource procurement. At that hearing, several participants recommended that interested parties collaborate on a blueprint for the revitalization of DSM activity in California. A collaborative working group was formed, with representatives from a broad range of interested parties, to develop this document. The Collaborative Blueprint was submitted to the Commission in January 1990.

Similarly, NRDC argues that, at least for the near term, "there is not much value...to be had in letting the ESCOs enter what is likely to be a losing fight." (TR, p. 266.) SESCO echos NRDC's concerns, stating that the ESCOs would lose in a replacement bid "because the utility would determine that the utility's own programs are superior whether or not they actually are." (SESCO Reply Brief, p. 1.)

DRA, on the other hand, expresses serious reservations about the concept of a partnership bid as a long-term bidding model. In DRA's view, the most useful contribution of ESCOs is the ability to provide a private sector "check" on the monopoly that utilities currently have for conducting DSM programs. (TR, p. 561.) To this end, ESCOs would become potential competitors with PG&E in providing lower cost energy efficiency services. DRA envisions a replacement bidding arrangement whereby ESCO bids (as with qualifying facilities (QFs) on the supply-side) would be compared directly with a planned PG&E program or programs. Under this replacement bid approach, either PG&E or the ESCOs would be selected via the bidding process to deliver DSM programs. In this way, ESCOs would become the "functional demand-side equivalent to QFs on the supply-side." (Ex. 9, pp. 3-5; DRA Opening Brief, pp. 3-4.)

SESCO and Transphase also present their views on where DSM bidding should head in the longer term. While supporting the partnership approach for PG&E's pilot, SESCO and Transphase urge the Commission to pursue integrated approaches in the future, where providers of both demand- and supply-side resources are able to compete in a common bidding arena. NRDC also testified in support of the principle of ESCOs competing with utilities, but only in the longer term. (TR, pp. 266-267.)

4.2 Shareholder Incentives

Under PG&E's proposal, the bidding pilot would receive shareholder incentive treatment identical to other PG&E resource programs. Minimum performance goals for this pilot would be

incorporated into revised goals for all of PG&E's resource programs, as part of PG&E's test year 1993 general rate case.[10]

PG&E argues that shareholder incentives are necessary for a partnership bid, in order to ensure the full cooperation and enthusiasm of utility personnel. (PG&E Opening Brief, pp. 6-7.) PG&E witness Chouteau testified that, without shareholder incentives, PG&E should not go forward with its partnership bid, as currently designed. (See Ex. 8, p. 6 and TR, p. 39.)

SCE, CEC, NRDC, ERA, Transphase, and SESCO support shareholder incentives, for similar reasons. In their view, failure to grant incentives could reduce a utility's sustained commitment to the success of DSM bidding and could discourage ESCOs from competing in the bidding process. SESCO testified that partnership bidding programs in other states, where the utilities received shareholder incentives on their own programs, also awarded incentives on ESCO-delivered savings.[11] SESCO also argues that PG&E should earn a return on ESCO-delivered DSM because, unlike QF projects, DSM programs represent a utility investment. (SESCO Brief, pp. 5-6.)

DRA, on the other hand, strongly opposes the notion that PG&E's pilot program must carry the opportunity for shareholder earnings in order to succeed. Although PG&E and others argue that DSM bidding would fail without incentive "symmetry," DRA points out that utility earnings are not increased from supply-side bidding by QFs. DRA also argues that PG&E's current DSM programs lack incentive symmetry since only a portion of PG&E's current energy efficiency programs, which are, in turn, only a subset of all PG&E DSM programs, are eligible to earn shareholder incentives. DRA is also concerned that, by including load management and fuel

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10 TR, pp. 526-528, 530-531.

11 TR, pp. 247, 260.

substitution projects as eligible for incentives, PG&E is expanding beyond the incentive treatment in place for its own programs.

Moreover, DRA questions the appropriateness of incentives in the longer term if PG&E's role becomes (as with QFs) largely one of administration, with virtually all of the risk being shifted to ESCOs. Finally, DRA points out that the issues of increased DSM spending authorization and increased earnings potential have been heavily contested in recent proceedings, and questions the appropriateness of increasing that potential in this forum. In particular, DRA argues that current procedures for the measurement and verification of DSM program savings require improvement before an expansion of earnings potential is warranted.

For these reasons, DRA's primary recommendation (Alternative 1) is to authorize recovery of the pilot program costs, at the level requested, but without authorizing shareholder incentives. DRA presents a secondary recommendation (Alternative 2), in the event that shareholder incentives are authorized for the bidding pilot. Under this alternative, PG&E would fund its bidding pilot without authorization for incremental funding (See Section 4.5.1 below). The recovery period of PG&E's earnings for ESCO-delivered projects would reflect the payment schedule of payments to ESCOs, rather than the current three-year recovery schedule (based on estimated savings). Moreover, the level of shareholder incentives would be adjusted downward to reflect the reduced risk to PG&E of shifting performance requirements to the ESCOs.

4.3 Bid Evaluation Issues

Almost all of the intervenors suggested changes to PG&E's bid evaluation procedures and criteria. As an overall theme, ESCOs, DRA, and others commented on the subjective nature of PG&E's evaluation criteria, and recommended ways in which the scoring could be made more objective and transparent. Parties' comments, by evaluation criterion, are summarized below.

4.3.1 Economic Attribute

PG&E proposes to evaluate the economics of each bid based on several criteria. First, as a threshold test, each project must pass the TRC test. However, PG&E states that it will not translate benefit-cost ratios directly into a score or ranking of proposals. Instead, PG&E will take into account several economic factors:

1. The results of the TRC and UC tests, but relying more on the results of the UC test;

2. A comparison of the type and cost of the measures to the bid price, so that PG&E can consider that higher bid prices may be justified for proposals that incorporate higher priced/longer payback measures;

3. A comparison of bid prices and cost-effectiveness results for like measures and market sectors, considering internal information on the cost of the measures delivered to the specified market sector; and

4. A comparison of the benefit-cost ratios of bid proposals to any of PG&E's existing or planned programs that are similar to the bid.

Once the bid proposals are evaluated, based on the above considerations, they are assigned a relative ranking within the economic attribute. Overall, the economic attribute is given a 45% weight in the final bid selection.

4.3.1.1 Cost-Effectiveness Tests

The TRC test compares the benefits of reduced supply costs (or "avoided costs") with the total costs of the DSM program, including both the program participants' and the utility's costs. The UC test is the same as the TRC, except that it excludes the participants' direct costs (or "customer contribution").

PG&E prefers to give greater weight to the UC test because, in PG&E's view, it minimizes the opportunity for ESCOs to

game the estimation of customer contribution. In addition, PG&E argues that the UC test minimizes the rate impact of the program. Transphase supports PG&E's usage of the UC test as the primary test of cost-effectiveness.

DRA agrees with PG&E that both the TRC and UC test should be considered in evaluating bid proposals, but prefers to combine the tests into a single formula, or figure of merit. Specifically, DRA recommends that the figure of merit for ranking ESCO bids should be the ratio of net TRC benefits divided by utility costs, i.e., the bid price plus utility administration expenses.[12] (Ex. 9A, Ex. 23.) DRA also points out that PG&E's formulas for both the UC and TRC test, as presented in the RFP, do not include the cost of shareholder incentives. In DRA's view, estimates of incentive payments should be included in costs, consistent with the Commission's proposed rules governing DSM activities.

SESCO argues that the TRC test is the appropriate ranking criteria for bid proposals. In SESCO's view, the Commission clearly stated in D.89-12-057, D.90-01-016, and the proposed DSM rulemaking that the choice of resources should be governed primarily by the TRC test. SESCO argues that the TRC test is the only test that captures the long-term resource benefits of DSM, and is consistent with evaluation methods used for supply-side resources. In SESCO's view, the level of customer contribution should not matter, as long as the total resource costs are minimized.

In contrast, the utility-only cost evaluation approach will force bidders toward fast payback, cream skimming projects,

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12 In its brief, DRA presents an alternative formula for its primary recommendation, i.e., if shareholder incentives are not authorized. This formula would be based on TRC benefits divided by total costs plus 50% of utility costs. See DRA Opening Brief, pp. 14-15, and Appendix A.

and penalize more efficient conservation programs, in SESCO's opinion. Moreover, SESCO argues that PG&E's motivation for preferring the UC test is to maximize its own earnings, not ratepayer benefits. This is because PG&E's current incentive formula is based on the difference between net resource benefits and utility costs. SESCO argues that PG&E's concern over gaming participants' costs can easily be addressed by holding the ESCO to those estimates. SESCO prefers the TRC test over DRA's figure of merit, since the latter still gives some weight to the level of customer contribution.

4.3.1.2 Incremental Customer Value

In calculating the customer's direct costs (also referred to as participant's costs), PG&E includes a factor called "incremental customer value." As defined in the RFP, this value represents any incremental benefit the customer receives due to the DSM program, other than the direct reduction in the PG&E bill. Bidders present an estimate of this value in their Response Package (see Ex. 5, p. 55). In applying the TRC test, PG&E proposes to subtract incremental customer value from the customer's direct costs, but only if that value is equal to or less than those costs.

ERA strongly supports the inclusion of all forms of documentable incremental customer value, such as productivity increases and increased sales of the customer's product (e.g., increased customer occupancy in a motel). DRA objects to the broad definition presented in the RFP, and supported by ERA, and prefers to limit customer value to such things as verifiable reductions in operating and maintenance costs (TR, pp. 711-714). SESCO argues that, by limiting incremental customer value to the level of customer costs, PG&E's TRC is biased towards measures that include customer costs, even if such measures are overall more costly than those which do not require any (or as high) customer contributions. In SESCO's view, PG&E should either allow the full incremental customer value to be counted, regardless of the level of customer

contribution, or not consider any incremental customer value in its TRC calculation.

4.3.1.3 Net-to-Gross Ratio (Free Rider Assumption)

The net-to-gross (NTG) ratio, which PG&E calls its free rider assumption in the RFP, is designed to discount the value of estimated energy savings to account for several factors. First, it accounts for free riders, who are customers who would have installed, solely at their own expense and without any payment from either PG&E or any third party, the energy efficiency measures installed as a result of the program. The NTG ratio also captures the "rebound effect," where, for example, people put in insulation and then turn up the heat to make themselves more comfortable for the same energy use. (TR, p. 378.)

In its RFP, PG&E proposes to use a uniform 0.7 NTG ratio across all bid proposals, which is consistent with the number adopted by the Collaborative for use in PG&E's own commercial, industrial, and agricultural (CIA) programs (TR, p. 71).

In their direct testimony, and during cross-examination, several intervenors articulated strong objections to the use of a uniform 0.7 NTG. During hearings, the assigned ALJ requested that parties meet informally to develop a range of NTG ratio options for her consideration. The parties presented those options in late-filed Ex. 26, and indicated which ones they supported in their briefs. The options are outlined below:

Option #1: Use NTG ratios consistent with PG&E's current proposal (0.7);

Option #2: Same as (1) but use 0.84 for residential measures consistent with weighted average for all PG&E residential measures (from Ex. 11);

Option #3: Use NTG ratios consistent with PG&E's current program measures (0.7 for all CIA measures, measure-specific values for identified residential measures, 0.7 default for other residential measures);

Option #4: Set default NTG ratios according to either (1), (2), or (3) for bidders who fail to demonstrate greater than a two-year payback. A payback greater than two years presumes a NTG ratio of 1.0;

Option #5: Set default NTG ratios according to either (1), (2), or (3). Bidders may specify alternative values based on any available information;

Option #6: Set default NTG ratios according to (3). Bidders may specify alternative values based on any available information; and

Option #7: No NTG ratio is used.

PG&E argues that the NTG ratios used for ESCO proposals should be consistent with PG&E's own programs. Moreover, PG&E states that it is not certain how to evaluate the individual NTG ratio proposals that could be presented under Options (5) and (6). Accordingly, PG&E supports Options (1), (2), or (3), and could, as a compromise, accept Option (4).

SESCO and DRA prefer Option (6). SESCO argues that PG&E's traditional rebate programs have relatively high free riders because of the "volunteer" approach that PG&E and other utilities take in marketing the programs. In SESCO's view, ESCO proposals may have very different free rider impacts, depending on the marketing strategy:

> "For example, if on ceiling insulation...if you are going down and saying...if you're willing to pay 900 I'll pay you the last hundred, that's going to have a fairly high free ridership. But a ceiling insulation program where the bidders pay 100 percent of the cost and goes into a neighborhood and does all thousand homes there, it's very unlikely that 30 percent of those people will have been doing that same thing. So I think you'd need to be specific to the individual measure and to the delivery procedures." (TR, p. 211.)

Accordingly, both SESCO and DRA argue that the ESCO should be able to present information or evidence related to its specific proposal that would refute the PG&E-specific NTG ratio assumptions.[13] Similarly, CEC supports a "rebuttable presumption" approach. (TR, pp. 539-541.) As a default, SESCO would support Option (5). In its Reply Brief, SESCO states that Option (3) is also acceptable.

Transphase, NAESCO, and ERA argue for the elimination of any NTG ratio adjustment in the bidding pilot, and support Option (7). In ERA's and NAESCO's view, it is highly unlikely that any free riders exist in the proposed bidding programs, based on the nature of ESCO-delivered services. Transphase believes that applying a free-rider adjustment on the demand side unfairly disadvantages DSM programs, relative to supply-side projects. In Transphase's opinion, there are similar supply-side "free riders," i.e., cogenerators that would build a plant in the absence of any utility payments. According to Transphase, the fact that these cogenerators receive payments for power is a form of free ridership. As an alternate position, Transphase would support Option (4).

4.3.1.4 Utility Administrative Cost Assumption

For cost-effectiveness testing, PG&E assumes that its administrative costs will equal 10% of the bid price, across all bid proposals. Administrative costs would cover the negotiation and administration of contracts, training for PG&E market representatives, providing winning bidders with information about customers and customer usage, material that PG&E produces to publicize the winning bidders' services, and any other cost to PG&E

13 DRA also argues that the NTG ratio should be applied to the measure costs, as well as the energy savings, consistent with the most recent revisions to the Standard Practice Manual. (See TR, pp. 733-736, and late-filed Reference Item G.)

in administering the program. (TR, p. 94.) These administrative costs, for winning bidders, would be borne by ratepayers. (TR, p. 455.) The 10% figure represents an average of PG&E's administrative costs for its own programs. (See Ex. 8, pp. 18-19 and Exs. 15, 16.)

Intervenors raised similar objections to this assumption, as they did for PG&E's NTG proposal. At the request of the assigned ALJ, parties presented the following options for the treatment of utility administrative costs:[14]

Option #1: PG&E administrative costs are set at 10% of bid price for cost-effectiveness testing. (PG&E's RFP Proposal.)

Option #2: PG&E develops estimate of "indirect" administrative costs applicable to all bids and expresses them as a fixed percent of bid price for bid evaluation purposes; bidders propose estimates of "direct" administrative costs associated with their bid, subject to evaluation and verification by PG&E, for which they will reimburse PG&E.

Option #3: PG&E provides a menu of administrative functions and their approximate cost; bidders specify which, if any, of those costs: (1) they do not want performed at all; (2) they intend to perform themselves at their costs; and (3) they want PG&E to perform for which they will reimburse PG&E.

Option #4: PG&E collects its administrative costs through rates, and the costs are not charged to the bidders, or considered in the bid evaluation or cost-effectiveness tests.

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14 See lated-filed Ex. 26.

While it is certain that some costs will go up (and others go down) compared to PG&E's own programs, PG&E argues that the 10% figure is a good starting point for a partnership bid, and the best estimate it can make with no experience in these kinds of bids. Accordingly, PG&E supports Option (1).

DRA, SESCO, and ERA support Option (3), which would require the bidder to pay for the specific administrative functions it requests from PG&E. SESCO and ERA argue that Option (1) would unfairly penalize some projects and subsidize others. Option (2) is equally unfair, in SESCO's opinion, because the utility could simply claim that it needs to "staff up" to handle the bid DSM projects, whether or not such staff is actually necessary.

In support of Option (3), SESCO's witness Esteves testified that every other state requires project specific administrative costs to be "internalized," that is, either included in the bid price or reimbursable to the utility. (TR, pp. 192-194.) ERA argues that direct costing of administrative functions is needed because there are a variety of ways an ESCO could structure its program to require more or less administrative oversight from PG&E. If PG&E cannot prespecify administrative costs, SESCO recommends that bidders be required to specify any administrative functions that PG&E must perform and the amount the bidder proposes to reimburse PG&E for performing those functions. Although originally supporting Option (4), CEC testified during cross-examination that it also prefers an approach where ESCOs are billed for administrative functions provided by the utility. (TR, p. 546.)

Transphase and NAESCO support Option (4).[15] NAESCO argues that the administrative cost adjustment represents an

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15 SESCO also supports Option (4) in addition to (3). As an alternate to (4), Transphase states that it would support Option (2), if the estimate of indirect costs is no greater than 7.0%.

unsubstantiated "penalty" to ESCO-delivered savings, and may overcompensate the utility for its DSM program design and implementation costs. Transphase argues in favor of Option (4) based on the Commission's expressed policy of "equivalence" between supply and demand-side resources. Transphase notes that PG&E collects the administrative costs associated with QF contracts through rates, and such administrative costs are over and above the avoided cost ceilings. (TR, p. 477.)

4.3.1.5 Avoided Costs

For the purpose of calculating the TRC and UC tests of cost-effectiveness, PG&E proposes to use the avoided cost assumptions presented in its 1993 general rate case application, or other current avoided cost assumptions, depending on when the RFP is finalized.

SESCO, NAESCO, and ERA point out that PG&E's current calculations of avoided costs do not account for environmental costs, and urge the inclusion of these impacts in evaluating bid proposals. In addition, SESCO and NAESCO express concerns that PG&E's calculations fail to account for avoided transmission and distribution costs (e.g., line losses).

In its Reply Brief, PG&E notes that environmental costs are being quantified in Investigation 89-07-004, the Biennial Resource Plan Update proceeding (Update), and that eventually avoided costs should be adopted in that proceeding. If these new avoided costs are adopted prior to the issuance of the RFP, PG&E states that it will incorporate them into the DSM test of cost-effectiveness. PG&E also points out that the avoided costs in the RFP do include line losses.

4.3.1.6 Other Economic Considerations

SESCO argues that the economic attribute should be evaluated purely on the difference between the bid price and PG&E's avoided cost for serving the customer. SESCO objects to the other general considerations outlined in the RFP, such as a comparison of

each bid to PG&E's internal assumptions about measure costs, or to PG&E's existing or planned programs. SESCO points out that PG&E's internal assumptions about such costs are not disclosed to bidders; the only information in the RFP appendices is the rebate per measure.

SESCO also questions how PG&E plans to use the comparison of bid prices and cost-effectiveness results for like measures and market sectors in its ranking process. In SESCO's view, these other considerations or comparisons should be removed from the RFP. If the Commission does allow PG&E to compare bid DSM projects with its own programs, SESCO argues that the comparison should include the total cost of the program, not just the utility rebate.

In evaluating the economic attribute, DRA generally supports the consideration of factors other than the results of cost-effectiveness tests. (TR, p. 733.) In particular, DRA appears to envision that ESCO bids would be evaluated on the basis of common sectors.[16] SESCO objects to this approach, noting the difficulties in ranking bids in one sector against those in another, and in establishing the number of MW to obtain in each, separately evaluated sector.

4.3.1.7 Relative Weighting

DRA recommends that substantially greater weight (i.e., 80-90%) be given to the economic attribute, as a further means of eliminating any unreasonable discretion in the selection process. For similar reasons, SESCO recommends that the economic attribute be given at least 60% weight in the overall evaluation process.

4.3.2 Compatibility Attribute

In its RFP, PG&E states that the ESCO bid proposals should be compatible with or complementary to existing and planned PG&E Energy Efficiency Programs, "rather than interfering or

16 DRA Opening Brief, p. 18.

competing with them." (Ex. 4, p. 28.) In Appendix A of the RFP, PG&E presents a brief description of its existing and planned programs. As a minimum threshold, the bidder has to describe how its proposal would fit into PG&E's current and planned programs and market coverage. In evaluating the bids, PG&E will consider such factors as different delivery mechanisms, sectors not covered or not fully covered by PG&E programs, and measures not supported by PG&E programs. The compatibility attribute is given a 10% weight in PG&E's overall selection process.

Transphase, NAESCO, and SESCO are concerned that this attribute may allow PG&E to arbitrarily disqualify bidders it perceives as being in competition with its planned in-house programs. Given the fact that this is a pilot program, SESCO believes that the consideration of this attribute should be eliminated altogether. Transphase would reduce the weighting factor to 5%.

4.3.3 Comprehensiveness Attribute and Eligibility

PG&E's RFP states that PG&E will give a higher ranking to proposals offering a comprehensive range of options to customers. (Ex. 4, p. 30.) In evaluating bids, PG&E will consider the range of end-uses affected by the proposal, and the comprehensiveness of the approach to each end-use. PG&E will also consider proposals which directly approach lost opportunities, i.e., DSM options which, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. The comprehensiveness attribute is given a 7% weight in PG&E's bid selection process.

DRA recommends that limited product bidders should not be eligible to bid. (Ex. 9, p. 19; TR, p. 478.) PG&E argues that limited service providers should be required to prove their value as avoiders of lost opportunities, under the comprehensiveness attribute. CEC and Transphase support PG&E's approach to evaluating comprehensiveness, and recommend that limited product

bidders remain eligible to bid.[17] SESCO recommends, and PG&E agrees, that bidders be allowed to present a tiered pricing structure, with higher prices paid for more comprehensive packages.

With regard to the types of DSM programs that are eligible, SESCO, NRDC, and DRA oppose the inclusion of fuel substitution programs, based on the concerns expressed in the DSM OIR/OII issued on August 7, 1991. SESCO also opposes the inclusion of load management programs, because these types of programs do not currently receive shareholder incentives. (SESCO Reply Brief, p. 1.) Transphase argues that load management programs should be eligible to bid, since the Commission's proposed rules state that they will be eligibility for shareholder incentives in the future. (TR, p. 277.)

ERA recommends that, in addition to hardware-oriented programs, any program that induces sustainable, documentable behavioral change should be eligible to bid. In ERA's view, this could include energy informational programs. DRA, on the other hand, would require that programs designed to affect customer behavior (e.g., changes in thermostat settings) include hardware that directly controls and monitors the equipment.

4.3.4 Measurement and Verification

The RFP requires bidders to develop a measurement and verification (M&V) plan as part of the bid response package. The M&V plan must demonstrate that program savings will be measured and verified on an annual basis using a "practical, feasible, reliable and statistically valid methodology," and must specify the procedures which will be used to confirm installation and operation of each project. (Ex. 4, p. 27.) In all cases, payments are directly linked to the results of M&V activities. Winning bidders can either submit invoices for payment after each annual M&V cycle,

17 See Transphase Reply Brief, pp. 2-3; CEC Opening Brief, p. 8.

or be paid in advance, subject to a post-verification true-up. In evaluating proposals, PG&E intends to give preference to proposals that request payment after verification. (TR, pp. 440-442.) PG&E gives the M&V attribute a weight of 15%.

All parties agree that the measurement and verification attribute is a critical aspect to DSM bidding, as well as to all utility DSM programs. Transphase recommends that the 15% weight assigned to the M&V attribute should be raised to 20 or 25%, to better reflect its relative importance.

In evaluating bidders' proposals, PG&E and Transphase support the case-by-case approach outlined in the RFP. ERA, on the other hand, suggests that standardized software be used. DRA raises concerns about the specific M&V methods that might be used in pre- and post-installation measurement, in particular, the choice of a baseline for calculating energy savings. DRA also recommends that supplementary utility measurement studies be authorized to improve savings forecasts.

In their comments on M&V issues, several parties note the differences between the M&V requirements for ESCOs and those associated with utility-sponsored DSM programs. Current shared-savings incentive mechanisms base payments to utility shareholders on forecasted, not verified, savings estimates. M&V results are used to improve future forecasts of program savings, but not to true-up payments that have already been made. ERA, SESCO, and NAESCO argue that the Commission should use the same standards of verification and measurement for utility-sponsored programs, as are applied to ESCO-delivered savings.

4.3.5 Scoring and Weighting Process

As described above, several parties recommend changes to the weights assigned to the compatibility, economic and measurement/verification attributes. In addition, SESCO, Transphase, and others object to the RFP language which permits

PG&E to alter the relative weights of its selection criteria, after the bids are received. (Ex. 4, p. 11.)

SESCO and NAESCO also recommend that the RFP disclose how bids are to be evaluated within each attribute, and how scores are comparable among attributes. For the economic attribute, SESCO proposes that each bid be expressed as a percentage of avoided costs, which is the inverse of rating bids on a benefit/cost ratio. For example, if the RFP assigned zero points to a bid at 100% of avoided cost, and two points for each 1% cost reduction, a bid at 75% of avoided cost would earn 50 points.

SESCO recommends that all other attributes be expressed in similar terms:

> "For example, the location attribute should be worth 3 points, with all energy saved within the favored location earning the 3 points. Similarly, an excellent measurement and verification plan...would earn 15 points, while a plan with little or no measurement or verification would earn 0 points. One method for assigning such points would be for a number of PG&E personnel each to rank order all bids on this attribute. The bid with the top ranking would earn 15 points, the bid with the bottom ranking would earn 0 points, and the intermediate-ranking bids would earn points ratably." (SESCO Opening Brief, pp. 11-12.)

SESCO recommends that PG&E be required to distribute summaries of project proposals and a final ranking, with associated scores for each attribute, at the time it publishes its "short list." Transphase recommends that future RFPs be even more objective, by providing for self-scoring by the bidders.

4.4 Contract Terms/Negotiation Process

In Ex. 6, PG&E presents a sample energy efficiency contract for winning bidders. The contract includes provisions on

payment terms, security requirements, force majeure, default and remedies, review of records and data, among others.[18] Negotiations could cover all aspects of the contract; however, bid price is negotiable only in response to an alteration in some other aspect of the bid. (Ex. 4, p. 12; TR, p. 179.) PG&E estimates that negotiations will take three months after announcing the short list. (Ex. 3, revised page 6.)

SESCO is concerned that some of the sample contract provisions discriminate against residential projects.[19] In particular, SESCO objects to the front-load security provisions in the sample contract, which require winning bidders to post acceptable security when payments to the bidder exceed that year's avoided cost savings. The security is reimbursed as the saved avoided costs accumulate and catch up to the payments. (Ex. 4, pp. 19-20; Ex. 6 pp. 85-86.) SESCO argues that these provisions may entirely preclude bids for residential sector conservation, since most homeowners are not willing to place liens on their houses in order to receive conservation treatment. In SESCO's view, these provisions impose more onerous conditions than those placed on PG&E's own conservation programs.

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18 In its Opening Brief, PG&E added information on how it intends to comply with General Order 156, governing the development of programs to increase participation of female and minority business enterprises in procurement of contracts from utilities. Specifically, PG&E will incorporate a specific statement on PG&E's Equal Opportunity Purchasing Program for Subcontracting into the RFP itself, and conduct outreach efforts to bring female and minority business enterprises into the process. (See PG&E's Opening Brief, pp. 31-32; Appendix.)

19 SESCO also points out that the RFP appendices provide very little information about PG&E's existing residential conservation measures, residential loads, assumed savings for residential measures, and other information that PG&E provides for commercial and industrial programs.

The sample contract requires program completion on or before January 1, 1996. SESCO is concerned that this provision could, in some cases, allow as little as two years from contract signing for the contractor to complete the project.[20] In SESCO's view, this short project period would preclude conservation developers from proposing sizable residential projects. SESCO recommends that PG&E allow each successful bidder the same number of months following Commission approval to complete its project. In SESCO's view, a period of 48 months would be appropriate.

SESCO also objects to the contract termination provisions, which allow PG&E to terminate "without liability of any description, kind, or nature whatsoever from PG&E to Winning Bidder." SECSO argues that PG&E should be required to pay for the work already completed by the contractor as of the date of termination, and should allow the contractor a reasonable ramp-down period. In SESCO's view, termination resulting from default by PG&E should require PG&E to pay the contractor a penalty. Finally, SESCO argues that there is no need to submit the sample agreement with proposed changes in its response package, prior to PG&E's selection of the short list. If that requirement is retained, SESCO urges the Commission to specify that PG&E assess no penalty in bid evaluation for changes to the contract.

In response to SESCO's concerns, PG&E argues that the front-load security provisions are no more onerous for residential conservation than for anyone else, and are included to mitigate ratepayer risk. Transphase supports PG&E's position on this issue. (Transphase Reply Brief, p. 4.) PG&E also points out that the RFP gives bidders flexibility to propose the form of front-load

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20 PG&E witness Berman testified that, under all of the worst contingencies, the contract provisions would allow for a 2-year 4-month project implementation period. The maximum implementation period is three years. (TR, pp. 179-180.)

security that works the best for them. With regard to the termination provisions, PG&E believes that the arbitration provisions for dispute resolution can be used to address SESCO's concerns. In PG&E's view, having bidders' preferences for the contract before selection of the short list will aid PG&E in comparing bids, in particular with regard to the economic attribute, and speed up the negotiation process.

4.5 Funding Issues/Commission Review Process

In their testimony and briefs, several parties raise issues concerning program funding and the Commission review process. These issues are summarized below.

4.5.1 Incremental Funding/Balancing Account Treatment

PG&E recommends that expenditures for DSM bidding be included in the existing gas and electric two-way balancing accounts for other PG&E resource DSM programs, i.e. the Customer Energy Efficiency Resource Program Balancing Account (CEERPBA). Specifically, PG&E requests that up to $500,000 in expenses associated with issuing the RFP, evaluating bids and negotiating contracts be added to the CEERPBA for 1992. For 1993 and beyond, PG&E requests that $48.6 million in 1992 dollars be authorized for inclusion in the CEERPBA to cover expenses for the three-year general rate case (GRC) cycle, and that the contract payments be found reasonable in future rates. Beyond 1995, PG&E plans to request specific funding in the appropriate rate case.

PG&E requests two-way balancing account treatment for a minimum of four years, beginning in 1992 and extending through the three-year project implementation period. Two-way balancing account treatment would enable PG&E to exceed the funding authorization in a given year and, similarly, carry forward any underexpenditures. PG&E also requests authorization to shift funds from other resource programs to its bidding pilot, within the limits authorized for other resource programs. As PG&E witness Rushing testified, PG&E is currently authorized to exceed its total

resource program budget by 130%, and spend up to 150% of any given resource program's budget. (TR, pp. 516-517.) However, PG&E would not shift funds from the bidding pilot to its other resource programs.

PG&E believes that the pilot program should be funded with incremental authorizations because: (1) PG&E was not given funding for this pilot in either the 1990 GRC or the Collaborative decisions (D.90-08-068 and D.90-12-071) and (2) the bidding pilot is not replacing PG&E programs. Although some incremental DSM program funding was included in PG&E's recent 1992 energy cost adjustment clause (ECAC) decision, PG&E asserts that it would be unfair to fund the 1992 pilot expenses with dollars otherwise earmarked for approved DSM programs benefiting PG&E's customers. CEC supports PG&E's request for incremental funding, arguing that PG&E should not be forced to choose between curtailing existing cost-effective programs and limiting or cancelling the pilot bidding program. (CEC Brief, p. 6.)

PG&E also argues that a two-way balancing account is needed because of the uncertainty over when contract payments will actually commence during the implementation period. (Ex. 8, p. 11.) Similarly, PG&E is concerned that the actual level of payments to ESCOs could exceed the upper limit of authorized funding. Even after signing contracts, PG&E asserts that there could be a plus or minus 15% variation in payments due to the under- and over-delivery provisions of the contract. (TR, p. 423.) For these reasons, PG&E requests the funding flexibility described above. Transphase supports this funding flexibility, arguing that without it, the utility could be forced to withhold payments to a winning bidder.

As described in Section 4.2 above, DRA's primary recommendation is to fund PG&E's pilot program without shareholder incentives. Under this alternative, DRA strongly recommends that shifting among resource programs not be permitted, and that

expenditures for the pilot program be given one-way balancing account treatment. Under the one-way balancing account treatment, PG&E would be authorized to carry-forward funds within the funding period, but could not exceed authorized levels in any period. Unspent monies, if any, would be returned to ratepayers, with interest. In DRA's view, this treatment is required to ensure that PG&E does not improperly shift costs or expenditures between resource programs that earn incentives and the pilot program.

If shareholder incentives are authorized, DRA supports the balancing account treatment proposed by PG&E. (See Ex. 9, pp. 20-21.) However, under this alternative, DRA recommends that PG&E use existing authorized funds to implement the solicitation and to conduct contract negotiations in 1992. Instead of authorizing incremental funding at this time, DRA recommends that funding for the bidding pilot be incorporated into PG&E's request for expanded DSM program funding in its test year 1993 general rate case.

4.5.2 Approval Of Negotiated Contracts

PG&E originally proposed Commission review of all contracts, as they are negotiated and signed. (Ex. 4, p. 13.) In its rebuttal testimony, PG&E suggested that the contracts be submitted to the Commission for informational purposes only. (Ex. 8, p. 13.) PG&E's current position is that the sample energy efficiency agreement should be approved as the standard contract for DSM bidding. PG&E would formally submit the contracts for Commission approval if the total funding for the bidder contracts exceed the authorized amount, or there are unresolvable issues or protests to the contracts. Contracts which do not require additional funding, or are noncontroversial, would be filed with the Commission for informational purposes by advice letter. (PG&E Opening Brief, pp. 15-16.)

DRA and SESCO strongly object to PG&E's current proposal, arguing that the proceeding was not focused and designed to develop

a standard contract for DSM bidding. Both SESCO and DRA also question how PG&E would determine which contracts are "noncontroversial" for the purpose of Commission review.

4.5.3 Appeals/Complaint Procedures

Transphase and SESCO recommend that the Commission establish an appeals process for unsuccessful bidders during the bid evaluation stage. In their view, an appeals process is particularly necessary because of the subjective evaluation criteria contained in the RFP. SESCO suggests that the Commission allow complaints to be filed during a period of 30 days after PG&E distributes the evaluation results. PG&E would be required to answer within 15 days, and the Commission would issue a final ruling within 45 days.

Transphase and SESCO also recommend that bidders have some formal recourse during the negotiation stage. For example, Transphase urges the Commission to provide an expedited, binding arbitration service to resolve contract negotiation disputes. SESCO recommends that, if negotiations are not complete within 120 days, the DSM bidder should have the opportunity to take the unresolved contract issues to the Commission for resolution. DRA also believes that Commission oversight during the contract negotiation stage will be needed.

5. Discussion

In their testimony and briefs, parties have raised very important issues regarding the form and design of DSM bidding programs. Over time, as we develop and evaluate alternative bidding approaches, we intend to reach final determinations on all of these issues. At this juncture, however, we are just beginning the process of testing competitive bidding for DSM. Before going forward with DSM bidding on a permanent basis, we will evaluate various aspects of the bidding pilots we initiate in this investigation, including the bidding form, the selection criteria

and the contract provisions.[21] Therefore, our objective today is to balance the need to experiment with bidding design and procedures with the need to make our first bidding pilot as meaningful as possible. With this objective in mind, we turn to the specific issues in this case.

5.1 Form and Size Of Bid

PG&E acknowledges that its proposal is not designed to be a supply-side equivalent bid. The partnership approach tests the competitive market among ESCOs, and examines how ESCOs can enhance and augment DSM activities in PG&E's service territory. Under a partnership bid, as proposed by PG&E, both winning ESCOs and utility shareholders are given the opportunity to earn profits.

As DRA points out, the partnership form of bid is very different from the bidding environment we have adopted for supply-side resources. Our bidding process for supply-side resources does not enable utilities to earn a return on winning QFs' projects. Nor are QFs limited to proposing supply-side projects that augment, rather than defer or replace, the utility's own construction plans. On the supply side, QFs compete head-to-head with the utility for planned resource additions. If the QF's bid is lower than the utility's proposed cost-effective addition, then the QF wins the bid and builds its own project.[22] If QFs cannot beat the

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21 PU Code § 747(c) directs this Commission, in consultation with the CEC, to report on the results of the pilot bid projects to the Legislature by January 1, 1993. Our proposed Rules direct Commission Advisory and Compliance Division (CACD) to coordinate this evaluation. We will consider CACD's findings and recommendations on the pilot bidding programs in a later phase of these proceedings.

22 The utility's proposed cost-effective addition is identified in our electric resource planning process, where utility supply-side resource options are compared for cost-effectiveness. The

(Footnote continues on next page)

utility's costs, then the utility meets the resource requirement itself, and shareholders earn a rate of return on the utility's investment. The clear benefit to ratepayers of this bidding approach is the downward pressure that competition creates on utility resource costs.

PU Code § 747 specifically directs utilities to test "the ability of demand side bidding to deliver benefits to utility customers." Therefore, the threshold issue before us is whether PG&E's proposed bidding structure has the potential for delivering benefits to PG&E's ratepayers. As discussed above, the primary ratepayer benefit of our supply-side bidding model is the resulting downward pressure on utility resource costs. As DRA points out, it is the "win-lose" essence of competition that results in the efficient delivery of services to customers. Since PG&E's bidding pilot does not subject the utility itself to competitive forces, it might not provide the type of ratepayer benefits (e.g., downward pressure on utility costs) that are generally attributed to replacement or integrated bidding forms.

However, we agree with PG&E and others that the partnership bidding pilot provides other forms of ratepayer benefits. For example, it benefits ratepayers by providing information about the longer-term viability of ESCOs in meeting California's energy resource needs. Moreover, a partnership bid could tap ESCOs' abilities to provide certain types of innovative, cost-effective DSM services, that PG&E would not otherwise pursue. We will not deny PG&E's proposal as a pilot experiment just because

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(Footnote continued from previous page)
least-cost resource additions identified in this process constitute the utility's "bid."

other bidding forms provide different types of ratepayer benefits. Indeed, we are pursuing different types of DSM bidding pilots to explore the various types of ratepayer benefits that each one contributes.[23] We will make any final determinations on the preferred form of bid as part of our evaluation of the pilots. In doing so, we will consider which bidding form best serves the objective of PU Code § 747, namely, to deliver benefits to utility customers.

While we are willing to experiment with different bidding forms, we must also be sensitive to the ratepayer costs associated with each bidding experiment. For its 50 MW partnership bid, PG&E requests an estimated $41 to $72.5 million in ratepayer funding (in 1992 dollars, NPV). Based on PG&E's comparison table, this represents an increase of 28% to 50% over PG&E's 1992 funding levels for similar DSM resource programs, not including shareholder incentives.[24] Moreover, a 50 MW pilot is equal to more than half of the results of PG&E's own energy efficiency programs in 1990, and more than a third of the estimated 1991 results.[25] The record does not justify a pilot program of this size and cost. In our view, a 20 MW bidding pilot would provide sufficient testing of PG&E's partnership proposal without exposing ratepayers to excessive costs. As we discuss further in Section 6 below, a pilot

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23 As we state in D.92-02-075 (mimeo., Attachment 1, Rule 27), we also expect to see a DSM-only replacement bidding pilot proposed for our consideration. Pursuant to PU Code § 747, one or more energy utilities will also implement a pilot integrated bidding system.

24 See Ex. 25B and TR, pp. 603-605, 667-670. The comparison is made between column 2 and the figures for load management, residential and CIA resource programs in Column 3, Ex. 25B.

25 Item by Reference A, pp. I-12 and I-13; PG&E's Opening Brief, p. 36.

program of 20 MW more appropriately meets our objectives for the pilots, pursuant to PU Code § 747. Accordingly, we direct PG&E to reduce its bidding pilot awards to a maximum of 20 MW. PG&E should reflect this change in its RFP, along with the other modifications described below.

5.2 Shareholder Incentives

We also agree with DRA that our current bidding framework for supply-side resources does not include shareholder incentives. However, as we discuss in Section 5.1 above, the partnership form of bid is not designed to be a supply-side equivalent bidding process. Therefore, we must evaluate the role of shareholder incentives within the context of this experiment's purpose, namely, to test ESCO's ability to deliver DSM services to California customers on a reliable basis. The longer-term evaluation of what bidding forms and features best meet our resource procurement goals will be addressed in a later phase of this investigation.

In considering the issue of shareholder incentives, it is useful to describe how, in our view, PG&E's partnership proposal fits within its overall DSM program. As PG&E states, the funding and minimum performance goals for the pilot bid are included in PG&E's overall program request for test year 1993. As proposed, the pilot program is structured to augment both program funding and shareholder earnings potential, relative to current levels of authorization. PG&E plans to assist ESCOs in marketing their complementary services, side-by-side with PG&E's own programs.

In essence, PG&E will be contracting out to winning ESCO bidders for the delivery of complementary or expanded DSM services in its service territory. In exchange for the delivery of verified savings, a winning ESCO is provided an opportunity to earn a profit (i.e., the difference between its actual costs and its bid price). PG&E shareholders, in turn, earn an incentive equal to a percentage of the resource value of delivered savings minus the ESCO's bid price and administrative costs. At the same time, PG&E's personnel

are relieved of most of the effort in marketing and delivering the projected savings. That onus is placed on the winning ESCO. However, PG&E is still responsible for ensuring that its minimum performance standards are met, which will be raised to reflect bidding savings goals. (Ex. 1, pp. 5-6.)

Viewed in this manner, the inclusion of shareholder incentives in PG&E's pilot allows PG&E to remain relatively indifferent between subcontracting with ESCOs or performing the expanded DSM services itself. This is clearly a benefit to ESCOs who, without this pilot, could only bid for subcontracting services based on time and materials for the measures installed. (TR, p. 208.) It is also in PG&E's shareholders' interest to maintain this indifference, rather than being directed to give up earnings potential for the subcontracted portion of its resource programs.

It is also in the ratepayers' interest to obtain information about the potential for ESCOs to effectively provide DSM services, which is the type of information that a partnership bid can provide. We recognize that ratepayers' costs would be lower if PG&E's proposed pilot did not include shareholder incentives. However, we also are persuaded by PG&E and others that the partnership pilot is unlikely to yield useful information if PG&E has a financial incentive to favor its own programs over those delivered by ESCOs. While Commission directives could compensate for this bias, as DRA suggests, we prefer to retain the incentive model we adopted in D.90-08-068 as the framework for this form of bidding.

In other words, as long as the purpose of the pilot is to test the ability of ESCOs to deliver reliable savings in a subcontracting/partnership mode (and not as competitors), we see no compelling reason to pull the pilot out of the subset of programs that are currently eligible for shareholder incentives. Moreover, we note that the added costs of shareholder incentives are relatively small. For a 50 MW pilot, PG&E estimates that the

incremental cost of shareholder incentives would not exceed approximately $5 million (1992$, NPV).[26] Since we have reduced the size of PG&E's bidding pilot to 20 MW, the incremental cost to ratepayers of shareholder incentives will be commensurately lower. In its January 31, 1992 compliance filing (Ex. 27), PG&E estimates that shareholder incentives for a 20 MW pilot would not exceed $1.8 million (1992$, NPV).

On balance, given the experimental nature of this program and its reduced size, we are comfortable with the inclusion of shareholder incentives in a partnership form of bid. For this pilot, shareholder incentives associated with the partnership bid will be calculated on the same basis as the incentives for PG&E's own resource programs.[27] We will apply the shareholder incentive mechanism adopted in PG&E's current GRC proceeding (A.91-11-036) to the savings achieved through this pilot bidding program, subject to any further modifications we may make to PG&E's shareholder incentive mechanism by subsequent Commission order.[28] However, our decision to include shareholder incentives is unique to the

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26 See TR, p. 411.

27 DRA's proposal to adjust the level of incentive downward is premature at this time. We do not have sufficient information on the record with which to assess the relative risk to PG&E of a partnership bid, vis-a-vis PG&E's own programs. However, we intend to revisit this issue after CACD has completed its evaluation of the bidding pilots, and may reconsider DRA's proposal for any subsequent bidding proposals.

28 The shared-savings incentive mechanism being considered for PG&E's own DSM programs in A.91-11-036 is to be consistent with the guiding principles we adopt in D.92-02-075, pending our comprehensive review of shareholder incentive mechanisms in a later phase of this proceeding. (See D.92-02-075, Attachment 1, Rules 14-19.) If our later review indicates that further modifications to PG&E's incentive mechanism for its own DSM programs are warranted, we would apply those modifications prospectively to the savings achieved from this pilot.

form, size and ratepayer impacts of PG&E's bidding pilot, and should not be viewed as precedential for other bidding forms or proposed bidding pilots.

5.3 Bid Evaluation Issues

Under its pilot bid proposal, PG&E asks for broad discretion in weighing various features of each bid against the same or different features of competing bids. We have the same reservations about this approach for DSM as we've expressed in evaluating similar proposals for supply-side bids; namely, that the process is highly subjective, particularly without a suitable basis for establishing advance weighting criteria.[29] However, on an experimental basis, we are willing to proceed with PG&E's proposal, provided that certain aspects of the ranking and weighting criteria are made more objective and transparent, as recommended by parties to this proceeding. In its brief, PG&E agrees to eliminate the RFP language which permits PG&E to alter the relative weights of its selection criteria, after the bids are received. (PG&E Reply Brief, p. 4.) We direct PG&E to make that change to its RFP, along with the other modifications outlined below.

5.3.1 Economic Attribute

We recently issued rules governing the evaluation, funding, and implementation of DSM programs (Rules).[30] Rule 6 states that, for programs that serve as alternatives to supply-side resources, we rely on the TRC test as the primary indicator of DSM program cost-effectiveness. This is appropriate because, unlike the UC test, the TRC test looks at the total resource costs of DSM options in making comparisons among programs. Basing the ranking

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29 During our consideration of initial proposals for evaluating QF bids, we rejected a similarly subjective "multi-attribute" RFP approach. (See D.86-07-004, mimeo. p. 77 (21 CPUC 2d 377).)

30 See D.92-02-075, Attachment 1.

and funding of DSM programs primarily on the UC test would lead to the inefficient allocation of resources, since investments would be based on an evaluation of only a portion of total costs. For this reason, we look at total costs and benefits in evaluating supply-side resources, as SESCO points out. Therefore, we direct PG&E to use the TRC test, and not the UC test, as the primary indicator of cost-effectiveness in ranking bid proposals under its pilot bidding program.

DRA and PG&E argue that the utility's costs, in particular the level of customer rebates, should also be considered in evaluating bid proposals, in order to keep ratepayer costs as low as possible. We agree that rebate levels should be considered, but have serious problems with both PG&E's and DRA's proposed approaches for doing so. PG&E's approach is highly subjective and, even under extensive cross-examination, PG&E witness Berman could not describe precisely how utility costs would weigh into the selection process. (TR, pp. 145-156; pp. 390-391.) For example, witness Berman could not indicate which of the following hypothetical bids in the same sector would score higher on the economic attribute, all other things being equal: a bid at 60% of avoided costs, with zero customer contribution; versus a bid at 80% of avoided costs, with 40% customer contribution. (TR, pp. 145-146.) Moreover, when asked questions on how PG&E would consider its own project costs in the evaluation process, PG&E witness Berman indicated that bids with higher total costs could be chosen over those with lower total costs, depending on the level of PG&E's own rebates, relative to the bidders' proposals. (TR, pp. 146-147, pp. 152-156.)

Similarly, DRA could not describe what to expect from a single figure of merit, in terms of the tradeoff between lower total costs and higher utility costs. However, based on the examples in DRA's Exhibit 23, it appears that DRA's figure of merit proposed for a partnership bid that includes shareholder incentives

would result in a selection preference for ESCO bids with relatively higher total costs, but lower utility costs. (See TR, pp. 696-698.)

We prefer to explicitly state what the tradeoff between total costs and utility costs should be in evaluating bid proposals, so that the process is more objective and transparent than proposed by PG&E. Otherwise, neither bidders nor evaluators will have a clear understanding of how the economic characteristics of bid proposals will be evaluated, relative to each other. By stating this tradeoff as clearly as possible, we hope to minimize after-the-fact controversy over scores for this attribute in PG&E's bid selection process. Moreover, we want to make sure that the tradeoff is made in a manner that is consistent with our resource procurement objectives, as stated in the DSM OIR and reaffirmed by D.92-02-075. As we discussed above, the Rules emphasize the consideration of total resource costs and benefits in evaluating all resource options. In other words, the primary consideration under our resource procurement framework is to select the most economically efficient resource for meeting energy needs.

This does not mean that ratepayer impacts are ignored in reviewing and approving DSM programs. As we state in D.92-02-075, we will always need to examine the rate impacts of pursuing least-cost resource options. For utilities' ongoing programs, we look at potential rate impacts in deciding the overall level of DSM funding to authorize in a given period.[31] Similarly, in today's order, we take rate impacts into account by limiting the overall size and funding for PG&E's pilot. (See Section 5.1 above.) However, for the purpose of ranking DSM programs, relative to one another, we believe that the primary criterion should be economic efficiency,

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31 See D.92-02-075, mimeo. pp. 38-39.

i.e., which programs yield the greatest net benefits from a total resource perspective.

Since relative economic efficiency is best measured by the TRC test, we believe that bid proposals should be ranked based on that indicator, for the purpose of establishing a score under the economic attribute. The relative level of utility costs associated with each bid proposal should not reverse that ranking. Rather, we will use the UC test as a "tie breaker," that is, for projects with the same TRC benefit/cost ratio (or the same percentage of avoided costs), the one with lower utility costs (i.e., a higher UC test benefit/cost ratio) should be ranked higher.[32] For example, if Bid A has total costs (including customer contribution) that equals 60% of avoided costs (or, has a TRC of 1.67), and Bid B has total costs that equal 80% of avoided costs (TRC of 1.25), Bid A should be ranked higher than Bid B for the economic attribute, irrespective of the level of customer contribution/utility costs. However, if there are two bids with total costs equal to 60% of avoided costs, PG&E should rank the project with a higher UC test benefit/cost ratio above the other, within the economic attribute. Both bids at 60% of avoided costs would still be ranked below a bid with total costs equal to 59% of avoided costs.

We agree with SESCO that PG&E's concern over the potential gaming of customer contribution estimates should be addressed by holding the ESCO to those estimates. Otherwise, as SESCO points out, the ESCO could end up being paid well over its

32 As SESCO points out in its Reply Brief (pp. 9-10), ESCO projects can be expressed as a percentage of avoided costs, which is simply the inverse of ranking projects on the benefit/cost ratio. For example, an ESCO project with total costs at 75% of avoided cost is equal to a project with a TRC benefit/cost ratio of 1.33.

bid price, at a total cost that could even exceed avoided costs. (See Ex. 14, p. 11.) Under its sample contract terms, PG&E already requires verification of total costs, including the customers' contribution, before payments commence. (TR, p. 168; Ex. 6, p. 91.) These provisions should be modified to indicate that, should actual customer contributions exceed the estimates presented in the bid proposal, PG&E's contribution will be reduced, commensurately. In other words, if an ESCO's bid is 80% of avoided costs, in terms of total resource costs, total payments from customers and PG&E should not exceed that level. (See TR, pp. 196-197.)

PG&E also argues that its own program costs should be considered in evaluating bids. However, PG&E does not adequately describe how it plans to consider these costs in evaluating bids, nor does it provide the necessary cost information. As indicated above, it is unclear what components of costs PG&E intends to compare (e.g., utility costs or total resource costs) and how PG&E would translate such comparisons into relative rankings. Moreover, the appendices to PG&E's RFP do not provide consistent total cost information for its current and planned programs.[33] PG&E witness Rushing also indicated that PG&E might not be able to identify its

33 At one point during the hearings, PG&E argued that total cost information (i.e., PG&E's rebates, administrative costs plus customer contributions) should be confidential, or else bidders would simply bid just under the utility's costs, and not reveal their lowest acceptable bid price. At a later point in the hearings, PG&E acknowledged that total cost information was published for at least its commercial and industrial programs in PG&E's annual reports on DSM. We believe that total cost information should be made available to potential DSM bidders, just as it is for supply-side bidders (e.g., QFs). The potential bidder needs to know, before committing time and resources in developing a bid proposal, whether its project has any possibility of success in the bidding process. Competition from other ESCOs should motivate bidders to keep their prices down.

total costs for all current and planned DSM programs, particularly in the residential sector. (TR, pp. 513-516; 523-525.)

We have no problem with the concept of comparing ESCO bids with the costs of PG&E's own programs. In effect, this is similar to what we do in supply-side bidding, where the QF bids against the utility's least-cost resource additions. However, this comparison should be made explicit in the evaluation process, if it is to be made at all. The most straightforward way to do this is to establish PG&E's program costs as the "avoided cost" yardstick for bid proposals that are similar to current or planned program activities.

This requires that PG&E make available its TRC ratios for a broad range of current and planned DSM measures, across all sectors. We agree with Transphase that, if any comparisons with utility program costs are made, those costs should represent total resource costs. Comparing total costs of ESCO projects with only a portion of the resource costs associated with utility-sponsored DSM would bias investments in favor of utility programs and, as discussed above, lead to the inefficient allocation of society's resources.

For DSM programs where PG&E does not have identified cost-effective programs (current or planned), the ESCO would bid a percentage of avoided supply costs. Where PG&E does have identified cost-effective programs, the ESCO would bid relative to PG&E's total program costs which, in order for those programs to be cost-effective, would be lower than avoided supply costs. This is essentially what happens for supply-side bidding, where QFs bids are evaluated relative to published cost information on the utility's planned resource additions.

For example, suppose Bid A has a TRC of 1.60 (which can be expressed as 62.5% of avoided supply costs), and Bid B has a TRC of 1.80 (55.5% of avoided supply costs). If the utility has no current or planned programs similar to Bid A or Bid B, the bids

would simply be ranked based on the above TRCs, or percentages of avoided costs. In this example, Bid B would be ranked higher than Bid A.

Let us assume now that the utility has a current or planned program similar to Bid B, with a TRC of 1.50 (67% of avoided supply costs). However, the utility does not have a current or planned program similar to Bid A. Bid B would now be viewed as a proposal at 83% of avoided costs (i.e., 1.50 divided by 1.80).[34] This is because the new "yardstick" for evaluating Bid B is not 100% of avoided supply costs, but rather 67% of avoided supply costs, which is the cost at which the utility can implement the same DSM activities. In this example, Bid A would be ranked higher than Bid B.

We will leave it up to PG&E to determine whether, for this particular pilot, it is feasible to provide bidders with TRC information in advance of the bid. If it is, PG&E should follow the procedures outlined above in the evaluation process. If PG&E is unable to provide the TRC information in advance of the bid, then PG&E should not consider its current or planned program costs in evaluating partnership bid proposals under this pilot.

We are willing to forego consideration of this information for PG&E's bidding pilot, because it is not primarily designed to examine whether replacing current or planned utility DSM programs with ESCO-delivered services can reduce total resource costs. Moreover, we have reduced the size of the pilot, and hence

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34 The bid's percentage of avoided cost is the utility's TRC benefit-cost ratio divided by the bidder's TRC benefit-cost ratio. If the utility does not have a DSM program to compare with, then the numerator (i.e. the utility's TRC benefit-cost ratio) is 1.00. This is because the utility would, under these circumstances, build supply as its least-cost resource option. By definition, the least cost supply option is reflected in avoided costs, and has a TRC benefit-cost ratio of 1.00.

the risk that ratepayers might have been better off if PG&E expanded its own DSM activities, rather than contracting for that expansion with ESCOs. We stress, however, that this type of information is critical for replacement or integrated bid forms, and we expect respondents to explicitly consider the total costs of current and planned utility-sponsored DSM in future pilot bidding proposals. We agree with DRA that, consistent with our proposed rules, estimates of shareholder incentive payments should be included in costs for both the TRC and UC tests of cost-effectiveness. We note that, during hearings, PG&E agreed to make this adjustment to its cost-effectiveness formulas. (TR, pp. 434-435.)

PG&E should modify its RFP to make the description of the economic attribute consistent with our discussion in this section. Other than the tests of cost-effectiveness described in this order, no other factors or criteria should be considered in evaluating proposals under the economic attribute. Project comprehensiveness, including the avoidance of lost opportunities, will be addressed by the comprehensiveness attribute described in Section 5.3.3 below.

5.3.1.1 Incremental Customer Value

With regard to incremental customer value, we note that PG&E does not currently include that value in calculating cost-effectiveness for its own DSM programs. According to PG&E witness Rushing, this is because PG&E does not currently have a way of determining that value effectively. (TR, p. 504.) DRA also testified that it also does not currently incorporate incremental customer value in its analysis of program cost-effectiveness. (TR, p. 713.) For this pilot, we will exclude consideration of incremental customer value consistent with current practices in evaluating utility-sponsored DSM. The Standard Practice Manual working group is an appropriate forum for exploring methods to quantify incremental customer value for consistent use across

utility-sponsored and ESCO-delivered programs.[35] We agree with DRA, however, that efforts to incorporate incremental customer value into the cost-effectiveness tests should focus on readily identified and quantified costs, such as avoided equipment replacement costs. (See TR, p. 717.)

5.3.1.2 Net-To-Gross Ratio (Free Ridership Assumption)

We agree with PG&E that, for this pilot program, it would be difficult to evaluate individual NTG proposals that could be presented under the "rebuttable presumption" approach endorsed by CEC, DRA, and SESCO. As PG&E points out, the results of ongoing free ridership studies will not be available in time to update NTG ratios for this RFP. (TR, p. 316-317.) At the same time, we want to accommodate parties' concerns that the NTG ratios adopted for PG&E's programs may be too low for certain types of ESCO-delivered programs.[36]

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35 In developing the Standard Practice Manual, the staffs of the CEC and this Commission formed an informal working group that included most of the major utilities in California and other interested parties. In the Order Instituting this Rulemaking, we also encouraged this working group to address technical issues related to indirect costs that may result from DSM programs. These include the costs of the customer's time to have an audit, arrange for equipment installation, and other transaction costs. (See TR, pp. 714-715; DSM OIR/OII, August 7, 1991, Rule 9.)

36 Contrary to Transphase's assertions, comparable "free riders" do not exist on the supply-side. When a customer is willing to install energy efficient equipment without a rebate, the utility is paying for something it would otherwise get for free, i.e., energy savings. In contrast, the utility would not get the energy production from the cogenerator if it did not pay for it--the cogenerator would simply use the cogenerated electricity and steam to meet its own internal needs, and demand less energy from the utility system. With cogenerators, the utility pays for the kwh "excess" that the cogenerator does not need for its internal use, and would otherwise not make available to the utility.

We think that Option 4, which sets the NTG at 1.0 for programs with greater than a 2-year payback, represents a reasonable accommodation of parties' concerns for our initial bidding pilot. As CEC Witness Messenger and NRDC witness Cavanagh testified, very short-term payback measures are more likely to have been installed regardless of the program, i.e., they would have a higher level of free ridership (and lower NTG ratios). (See TR, pp. 269-270, 537.) Option 4 would enable PG&E to differentiate among ESCO programs, with regard to free ridership, without a significant amount of added administrative difficulty.

For these reasons, we will adopt Option 4 in setting NTGs for PG&E's pilot program, which sets the NTG ratio equal to 1.0 for projects with a payback greater than two years. For bidders who fail to demonstrate greater than a two-year payback, the default NTG ratios will be set according to Option (3), i.e., at 0.7 for all CIA measures, at measure-specific values for the residential measures identified in Ex. 11, and at 0.7 for other residential measures. PG&E should modify its RFP and Response Package accordingly. We also agree with DRA that the NTG should be applied to the measure costs, as well as the energy savings, consistent with the most recent revisions to the Standard Practice Manual.[37]

5.3.1.3 Utility Administrative Cost Assumption

On the issue of administrative costs, we are persuaded by SESCO and others that administrative costs should be internalized, either by including those costs in the bid price or by making them reimbursable to the utility.

Although witness Berman includes within this category of administrative costs both bid solicitation and contract negotiation costs (TR, p. 94), we would exclude those types of costs from being

37 See Reference Item G.

internalized in the bid price or being made reimbursable.[38] As in the case of solicitations/negotiations with QFs or other utilities, those types of expenses are considered part of general contract administration costs, and are generally borne by ratepayers.

In contrast, the training of PG&E market representatives to assist ESCOs in their marketing efforts, providing customer energy usage information, producing publicity literature, and other project-related costs are integral to the ESCO's DSM program and delivery of energy savings. These types of administrative costs should be borne by ESCOs as part of their bid price, or made reimbursable to the extent that the bidding ESCO requests PG&E's services.[39] Otherwise, as DRA, SESCO, and ERA point out, ESCOs requiring less administrative oversight or involvement from the utility would be penalized relative to ESCOs requiring more oversight/involvement. Moreover, if ESCO bid prices do not reflect the full cost of achieving program savings, including utility administrative services, PG&E's evaluation of the economic attribute may not identify the least-cost providers of DSM services.

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38 Contrary to PG&E's assertions, the Standard Practice Manual does not require that the administrative costs associated with solicitation of and negotiations with third-party bidders be included in the TRC test. (PG&E Comments, p. 6.) This document refers only to the benefits and costs associated with utility-delivered DSM programs which, at the time of publication, were the only types of DSM programs under consideration. All of PG&E's administrative costs should, however, be considered for the purpose of evaluating this pilot program and reporting to the Commission.

39 We do not agree with Transphase that these types of costs are generally borne by ratepayers for QF projects, over and above avoided cost ceilings. QFs bear the costs associated with administrative functions related to the provision of energy services, including the costs of interconnection studies.

For these reasons, we will adopt Option 3. In its revised RFP, PG&E is directed to provide bidders with a menu of administrative functions and their approximate cost. In their response packages, bidders will specify which, if any, of those functions: (1) they do not want performed at all; (2) they intend to perform themselves at their costs; and (3) they want PG&E to perform for which they will reimburse PG&E. We expect PG&E to make good faith efforts in developing reasonable hourly rates and other cost information for this purpose.

5.3.1.4 Avoided Costs

PU Code § 701.1(c) directs this Commission to include a value for any costs and benefits to the environment in calculating the cost-effectiveness of energy resources, including conservation and load management. In our adopted Rules, we direct respondents to use avoided costs and nonprice (e.g., environmental) values that are consistent with the values developed in the Update. We expect to issue our order in the current phase of the Update before PG&E's bid evaluation phase is completed.

However, we recognize that there may be controversy over exactly how to translate Update findings into a specific 20-year projection of avoided costs for the purpose of evaluating DSM programs. For this reason, we directed parties to conduct workshops on this topic in D.92-02-075. CACD's workshop report will be submitted by November 1, 1992. As DRA and others point out, this schedule makes it impractical for PG&E to develop avoided costs for this pilot that are in compliance with the Update findings, without significantly delaying the RFP schedule. We also agree with DRA that bidders should know, in advance of bid submission, what avoided costs will be used to evaluate their projects.

Rather than hold up the issuance of the RFP, we direct PG&E to make sure that the revised avoided costs used for bid evaluation in this pilot are consistent with the avoided costs PG&E

proposes to use to evaluate its own DSM resource programs in its test year 1993 GRC. Once CACD has conducted the workshops required by D.92-02-075, and we have made further determinations on Update/DSM consistency issues, we expect PG&E and others to use those determinations in all subsequent applications of the Standard Practice Manual tests of cost-effectiveness.

5.3.2 Compatibility Attribute

As discussed in Section 5.1 above, we view the partnership bid as a form of third-party subcontracting for new/expanded DSM activities within the utility's service territory. We agree with PG&E that the partnership bid form should not be used to replace existing utility DSM activities, and therefore, ESCO bid proposals should state how they complement or are compatible with currently authorized programs.

However, we do not agree that ESCO activities need to complement planned program activities presented in PG&E's test year 1993 GRC application, or planned program expansions possible with PG&E's 130% funding flexibility, as PG&E's testimony implies. To do so would put ESCOs in somewhat of a "catch 22" situation, since: 1) a Commission decision on the GRC, including the types of new or expanded DSM programs PG&E should undertake, will probably not be issued prior to bid selection and 2) PG&E currently has considerable discretion to modify or augment its authorized DSM activities both within and across program categories. (TR, pp. 516-521.)

Accordingly, PG&E should clarify in its RFP that a DSM bid should not be considered incompatible unless it requires PG&E to discontinue an existing program providing the same measures to the same customers. Moreover, even if the DSM bid proposal is identical to one of PG&E's existing programs, it should not be disqualified if it provides those DSM services at lower total costs than PG&E's own program. Given the degree of flexibility that PG&E has to shift funds or redesign its resource programs, PG&E should

be willing to consider making its own programs complementary to partnership bid proposals that represent a cost-effective alternative to PG&E's own efforts.[40]

5.3.3 Comprehensiveness/Eligibility

We find DRA's proposal to disqualify limited product bidders to be overly restrictive. As DRA witness Schultz acknowledged, DRA's proposal could reasonably be interpreted to preclude a customer from bidding for measures on its own site, or any ESCO from focusing on a particular market sector. (TR, pp. 690-691.)

Consistent with our adopted Rules, the RFP is clear that PG&E will give favorable consideration to bids which avoid lost opportunities--either through comprehensive approaches or by focusing on specific lost-opportunity resources.[41] We consider this emphasis to be appropriate, at this time, for PG&E's bidding pilot. As we continue to experiment with DSM bidding and learn more about the potential role of ESCOs in resource procurement, we may reexamine the eligibility issues raised by DRA. (See Ex. 9, pp. 9-11; TR, pp. 478-479.) In addition to the evaluation criteria outlined in Ex. 2, Section K., PG&E should indicate that ESCOs that bid prices in a tiered system will be given favorable consideration under this attribute.[42]

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40 See TR. pp. 452-455, 506-507, 516-518.

41 See D.92-02-075, mimeo. Rule 2.

42 Under a tiered system, bidders offer different prices for increasing levels of achieved savings, in contrast to a system where bidders bid the same price for each and every kWh saved. As SESCO points out, a tiered system may encourage the winning bidder to pursue lost opportunities, without increasing the overall cost of the program. Allowing bidders to bid prices in a tiered system was also agreed to by PG&E. (See Ex. 14, pp. 19-21; TR, p. 449, PG&E Opening Brief, pp. 30-31.)

We also agree with PG&E and ERA that bidders should be allowed to bid on all methods of energy savings, including behavioral changes that are not hardware-oriented. However, we would expect appropriate measurement plans, such as end-use metering, from a bidder sponsoring a behavioral change.

On the issue of incentives for load management and fuel substitution programs, we note that the Rules we adopted in D.92-02-075 address the application of incentives to these programs. Rule 16 expands the Collaborative agreement on eligibility to include, along with energy efficiency programs, "load management programs that promote energy efficiency" (as opposed to load building or load retention). Those types of programs are relatively easy to define and evaluate using the Standard Practice Manual tests of cost-effectiveness. Since it is the Commission's intent to allow incentives for load management programs that promote energy efficiency, we see no reason to eliminate these types of load management services provided by ESCOs from PG&E's bidding pilot.

In contrast, Rule 16 specifically states that fuel substitution programs should not be eligible for shareholder incentives, pending resolution of technical issues associated with assessing the benefits of these programs. Workshops to address these technical issues will be underway in 1992. Since we are in the process of developing a framework for assessing the utility's own fuel substitution programs, it is premature to offer these programs for bid. We therefore direct PG&E to remove fuel substitution programs from eligibility in its bidding pilot.

5.3.4 Measurement and Evaluation

As ERA Witness Goldberg and others acknowledge, there are currently many approaches being used to measure the savings from DSM programs, including a number of computer programs for evaluating savings in buildings. (TR, pp. 198-200, 360-363, 490-491.) We agree with ERA that it would be useful to achieve

more standardization and uniformity in measuring techniques for both ESCO- and utility-delivered programs, and our DSM Rulemaking/Investigation is the appropriate forum for making progress in this area.[43] However, we also believe it is premature to direct PG&E to develop and use standardized software to measure ESCO savings for this bidding pilot. Therefore, we believe that PG&E's proposal to let bidders propose their own measurement and verification programs, subject to PG&E's case-by-case evaluation, is reasonable for this pilot program.

In its testimony, DRA raises a specific concern about the baseline reference for calculating energy savings in pre- and post-installation measurement. Since much of the equipment available today is subject to minimum state or federal efficiency standards, DRA argues that the baseline reference should be the minimum standards equipment, not existing equipment. In its Opening Brief, PG&E agrees that this approach should be used in measuring energy savings for the pilot bidding program. (Ex. 9, p. 13; PG&E Opening Brief, p. 19.) PG&E should add language to its RFP requiring bidders to incorporate this approach in their measurement and verification plans, as appropriate. As ERA witness Goldberg testified, the information needed to develop this baseline should be available from the CEC. (TR, p. 370.)

5.3.5 Scoring and Weighting Process

In our view, PG&E's weighting process appropriately gives the economic attribute the highest weight (45%), with measurement/verification following second (15%). Although some parties would prefer somewhat different weights among the attributes, we see no compelling reason to make any changes for

43 The issue of how the results of measurement studies are linked to shareholder earnings for utility-sponsored DSM programs are addressed in a separate decision in these proceedings. (See D.92-02-075, Rules 20 to 22.)

this experimental program. Fine tuning of the weighting scheme, as well as other aspects of the bid evaluation process, can come later, after CACD's evaluation of the pilots. In particular, we expect CACD to evaluate how the current weighting scheme between the economic and comprehensiveness attributes affects the selection of bids that are designed to avoid lost opportunities. For now, we will leave PG&E's relative weights as proposed.

However, we agree with SESCO and others that PG&E's RFP should describe more specifically how bids will be assigned scores within each attribute, and how scores will be put on a comparable basis across attributes. PG&E should also make available summaries of project proposals, and a final ranking with associated scores for each attribute, to all bidders and anyone else requesting a copy. This information should be available at the time PG&E announces its short list of bid proposals for negotiation.

5.4 Contract Terms/Negotiating Process

Front-loading provides for payments to ESCOs above avoided costs during early years of the contract, with payments declining over time. Under such circumstances, an ESCO that fails to deliver energy savings early in the contract would have received overpayments to the extent of the front-loading. PG&E's proposed security provisions require that ESCOs post an acceptable form of front-load security.

In the past, we have allowed some front-loading in QF payments. In all cases, we have included security provisions that ensure the QF returns overpayments if it ceases operation before the end of the contract. For Interim Standard Offer 4, which allowed for front-loading of energy payments (as well as capacity payments), the contract terms included upfront security provisions

similar to the ones proposed by PG&E for its DSM bidding pilot.[44] Requiring front-load security for PG&E's pilot is consistent with our practice with QF contracts when front-loading is extended beyond the capacity component of avoided costs.

Contrary to SESCO's assertions, the security provisions do not require SESCO to ask homeowners for liens on their homes or installed equipment; the provisions allow for other options, such as a letter of credit, performance bond or corporate guarantee. For the purpose of this experimental program, we find PG&E's proposed front-load security provisions to be reasonable. However, we note that all of the sample contract provisions are negotiable, and encourage PG&E to be open to considering other forms of security arrangements in the negotiation process. We also agree with PG&E that its arbitration provisions for dispute resolution can be used to address SESCO's concerns over contract termination.

Our decision today is not intended to preempt or discourage further discussions among utilities, ESCOs, Commission staff and others on the subject of front-loading and associated security provisions, or termination provisions. In developing standard offers for QFs, this issue was the topic of ongoing discussions, including informal workshops, where parties developed consensus on many contract terms. We encourage the DSM Bidding Advisory Committee to continue discussions on this and other contract-related topics for our consideration in the upcoming submittals on bidding pilots.

With regard to the program completion date, we agree with SESCO that a uniform period for all projects is more appropriate than PG&E's proposal. PG&E should modify its sample contract to allow for a uniform 36 months (the maximum allowed under its

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44 See, for example, D.83-09-054 (12 CPUC 2d, 626-627), D.86-07-004 (21 CPUC 2d, 352), and D. 91-06-022, mimeo. pp. 45-47.

current contract provisions) for project completion, following Commission approval.[45] As described in PG&E's RFP, winning bidders are allowed to negotiate changes to this, as well as any other sample contract provision, as part of the contract negotiation process.

Finally, if PG&E continues to require the sample contract with proposed changes in its response package, it should specify in the RFP that the changes will not be considered in the bid evaluation process. The evaluation process should consider only the attributes described in the RFP, as modified by this order.

5.5 Funding Issues/Commission Review Process

As discussed in Section 5.1 above, we are unwilling to fund this bidding pilot at the 50 MW level requested by PG&E; instead, we are authorizing today a bidding pilot program of up to 20 MW. DRA's proposal would require that the 20 MW pilot program be completely subsumed within PG&E's overall request for incremental funding for its own programs in the 1993 GRC. In concept, this suggestion has some merit: PG&E would be required to subcontract 20 MW worth of planned new DSM activities, rather than conduct those new activities itself. Since the partnership form of bid is designed to augment and complement PG&E's DSM programs, it would seem logical to put that concept to the test in the GRC, where PG&E is requesting authorization for new/expanded DSM programs.[46]

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45 For contracts that PG&E considers uncontroversial, and enters into without Commission preapproval, this provision should allow for 36 months from the date of ESCO signature. See Section 5.6 below.

46 In its GRC application, PG&E is requesting approximately $40 million in increased annual DSM funding, not including the pilot bidding program.

However, until the bidding is complete, neither the Commission nor PG&E knows which market sectors or types of programs the ESCOs will compete for to provide, effectively, subcontracting services for expanded DSM services. And, since the GRC proceeding is conducted under a rate case plan with specific time constraints, we cannot hold up that proceeding while we find out where ESCOs will provide the 20 MW worth of additional DSM services, in order to ascertain where PG&E should focus its own DSM efforts. Therefore, it appears impractical to do as DRA suggests. At the same time, we recognize that the partnership form of bid effectively expands PG&E's DSM activities (via ESCO subcontracting) and its shareholders' potential for earnings. Therefore, our decision today to authorize incremental funding for this pilot will be taken into consideration as we evaluate PG&E's overall DSM funding request in the GRC. Moreover, as PG&E recognizes, minimum performance goals for this pilot will be incorporated into revised goals for all of PG&E's resource programs.[47]

In sum, we are willing to authorize increases to the CEERPBA for 1992 and beyond for PG&E's DSM bidding pilot, as modified by this order. By ruling dated January 22, 1992, the assigned ALJ set aside submission of PG&E's proposed DSM pilot bidding program to obtain revised cost estimates from PG&E for a 20 MW pilot. In that submittal (Ex. 27), PG&E estimates that approximately $500,000 will be needed to cover 1992 solicitation

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47 However, PG&E has not presented a proposal on how or when it intends to make these revisions. (See TR, pp. 520-522, 527-528.) Within 15 days from the effective date of this order, PG&E should file comments on a schedule and procedural forum for making these revisions. Interested parties may file reply comments within 30 days from the effective date of this order. PG&E's comments should be served on all parties to these proceedings and A.91-11-036, PG&E's test year 1993 GRC.

and contract negotiation costs and $17.5 million (in 1992 dollars) will be needed to cover expenses for the three-year GRC cycle.[48]

Therefore, by this order we authorize PG&E to increase its CEERPBA revenue requirement by $500,000 for 1992 and by a total of $17.5 million to cover DSM pilot bidding program expenditures for 1993, 1994, and 1995. PG&E is authorized to collect the 1992 revenue requirement increase ($500,000) as part of its current GRC or next ECAC proceeding. The 1993-1995 revenue requirement increase should be consolidated with that of PG&E's current general rate case (A.91-11-036) for the purposes of revenue allocation and rate design. Beyond 1995, PG&E should request specific funding in the appropriate rate case. We also authorize the two-way balancing account treatment proposed by PG&E for the 1992 through 1995 period. As PG&E proposes, however, shifting funds from the bidding pilot to its other resource programs will be prohibited.

5.6 Approval of Negotiated Contracts/Complaint Procedure

We agree with DRA and others that the individual contracts negotiated for this pilot program should be submitted for our review, as originally proposed by PG&E in its direct testimony. The sample contract (Ex. 6) was not, as PG&E suggests in its Opening Brief, presented as a "standard offer" for our consideration in this proceeding. Standard offers represent

48 In its submittal, PG&E presented two scenarios of costs for the reduced pilot size. The first incorporated the same assumptions as PG&E used for its 50 MW proposal. The second included revised assumptions to account for the possibility of less competitive bids and/or higher administrative costs as a proportion of total costs. For a 20 MW bid pilot, PG&E estimated 1993-1995 costs at $16.5 million for scenario #1, and $18.6 million for scenario #2. We are authorizing the approximate mid-point of that range, i.e., $17.5 million. For 1992 administrative costs, we are authorizing the lower end of the estimate (i.e., $500,000), given the amount of funding flexibility PG&E has within its current DSM funding levels.

boiler-plate forms which become effective contracts when signed by the third-party energy service provider (in this case, the ESCO). Payments made under standard offer contracts are automatically recovered in rates, i.e., the reasonableness of contract payments are not later evaluated in reasonableness reviews. For QFs, standard offer contract terms and provisions were carefully reviewed as part of a consolidated proceeding, A.82-04-44 et. al. In contrast, PG&E's sample contract was presented and evaluated as a starting point for negotiations and, hence, given only cursory review by most parties.

Therefore, we expect to review the reasonableness of the negotiated contracts, and associated payments, between PG&E and winning bidders, as PG&E originally proposed. However, this review does not need to take the form of preapproval. PG&E may sign what it considers to be "noncontroversial" contracts without preapproval from this Commission. Instead, those contracts would be subject to reasonableness review in PG&E's ECAC proceeding, consistent with the treatment of all other negotiated power purchase agreements that PG&E enters into without Commission preapproval.

Should PG&E decide to submit some or all of the contracts for our preapproval, we require that these contracts be submitted for our review at the same time, rather than one-by-one as they are signed.[49] PG&E should request preapproval of these contracts by filing an application, with service on all parties to this proceeding. We would issue findings at the time of preapproval on the reasonableness of payments made under those contracts. We recognize that some ESCOs may prefer to start their project immediately after signing the contract with PG&E, but for review

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49 If a selected number of contracts are requiring more time for negotiation, PG&E can submit the majority of contracts first, with a second grouping to follow.

purposes, we need to have some frame of reference (e.g., other negotiated contracts with ESCOs) in order to evaluate the reasonableness of individual contracts. We can conduct that type of comparative review in ECAC reasonableness reviews, and require similar information for these preapprovals, particularly since they are the first of their kind. As discussed in Section 5.4 above, all winning bidders will have the same amount of time from the date of Commission approval to complete their projects. Therefore, this requirement will not disadvantage projects with longer lead times.

PG&E can help to expedite the preapproval process by providing sufficient information on the cost impacts of each negotiated contract (i.e., by comparing year-by-year total project costs under the contract with long-run avoided costs). In addition, as part of its application for any preapprovals, PG&E should provide a comparison of similarities and differences among the negotiated contracts, with respect to specific contract provisions.

Finally, on the issue of an appeals process, we note that we have required modifications to PG&E's evaluation criteria that will make the process more objective. This should reduce, if not eliminate, the number of disputes over bid selection. Moreover, our current complaint procedures are available to all ESCOs, as they have been to QFs for resolving bid selection or negotiation disputes. We are not willing to establish a separate appeals process for this pilot program. As part of our overall evaluation of the DSM bidding pilots, we direct CACD to assess whether such disputes can be minimized through alternative program design, and whether an alternative appeals process is appropriate.

5.7 PG&E's Compliance Filing

In compliance with today's decision, we direct PG&E to revise its RFP, Response Package and Sample Contract (i.e., Exs. 4 through 7), and to file those revisions within 60 days from the effective date of this order. Comments on PG&E's compliance

filings shall be filed within 90 days from the effective date of this order. We remind parties that this comment process does not give them the opportunity to reargue their positions; rather, it is designed to solicit comments on whether PG&E's revisions comply with today's orders.

PG&E's compliance filing and interested parties' comments shall be filed at the Commission's Docket Office, and served on all appearances and the state service list in these proceedings. After reviewing the compliance filing and parties' comments, the assigned ALJ will either issue a ruling addressing any outstanding compliance issues and setting forth a final schedule for bid solicitation, or make recommendations to the Commission as to the appropriate course of further action.

6. Response to Comments on ALJ's Proposed Decision

Pursuant to PU Code § 311 and our Rules of Practice and Procedure (California Code of Regulations, Title 20, Rules 77 to 77.5), the Proposed Decision of ALJ Gottstein was issued before today's decision. PG&E, DRA, NRDC, CEC, and the Coalition For Energy Efficiency and Renewable Technologies (CEERT) filed timely comments on the proposed decision. SESCO submitted late comments, accompanied by a motion for leave to file late.. We grant SESCO's motion.[50] Finally, PG&E, DRA, and SESCO filed reply comments on March 3, 1992.

50 We note that SESCO telecopied its comments to the active parties by the filing date and, in doing so, did not jeopardize the ability of parties to file their responses to comments within the five-day limit.

We have reviewed and carefully considered the comments of the parties in adopting this Interim Opinion.[51] Parties' comments focused primarily on the issue of the size of PG&E's pilot program. In particular, several parties argued that we should not consider the ALJ's proposal to reduce the size of the pilot because, in their opinion, the issue of pilot size was not raised by parties to this proceeding and the record does not support the proposed reduction.

We disagree. We note that both SESCO and ERA raised the issue of size in their direct testimony (Ex. 14, pp.21-11; Ex. 21, pp. 11-12), and PG&E responded to their testimony in its Opening Brief (p. 36). The fact that none of the parties recommended a size reduction (as opposed to an expansion) does not preclude us from considering such a modification to PG&E's proposal. We point out that this is an investigatory proceeding which combines both adjudicatory and legislative decisionmaking elements. In such proceedings, it is well within our discretion to consider the same set of facts on the record (e.g., MW size and costs relative to current program activities) that PG&E used to argue for a pilot smaller than 200 MW (proposed by SESCO), in determining that a 20 MW size program better meets the objectives of the pilot. In addition, as within our discretion, we have provided parties the opportunity to comment on the proposed reduction in program size.

No party has addressed in comments the issue of the merits of taking specific additional evidence on a 20 MW versus 50 MW pilot. Moreover, parties' arguments in favor of retaining

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51 The ALJ's proposed decision incorporated the January 31, 1992 supplemental cost information provided by PG&E, but was issued prior to the receipt of the Febuary 14, 1992 comments (Transphase, SESCO and ERA) on the proposed reduction in pilot size and on PG&E's cost information. We have also reviewed and considered those comments in adopting today's order.

the larger program size are generally not supported by technical facts; rather they reflect the parties' perspective on what these pilots are designed to accomplish. Parties proposing to retain the 50 MW size generally take the view that the primary purpose of this pilot is to expand DSM services (and associated savings) or to foster ESCO development in California. For example, CEERT argues that the 50 MW size should be restored so that the pilot has "the potential for delivering needed megawatts of energy savings" and provides adequate incentives to "foster ESCO development and ESCO contributions toward meeting this state's energy efficiency goals." (CEERT Comments, p. 3 and p. 8.) CEC argues that a 50 MW level pilot is consistent with the Commission's stated commitment to "increasing the use of DSM as an energy resource," and should be supported for that reason. (CEC Comments, p. 4.) PG&E also argues that the larger pilot size is consistent with its "oft-stated goal...to achieve 2500 MW of DSM savings by the year 2000." (PG&E Comments, p. 10.)

In our view, the primary purpose of the bidding programs is to test various forms of competition <u>on a pilot scale</u> before committing to any single form. At this point in time, we do not know what the future competitive market in DSM will look like, or what exact role the ESCOs will play in that market. As we recently stated in D.92-02-075, "these bidding experiments will help us learn more about alternative DSM delivery mechanisms, and assess the role of DSM bidding to provide least-cost DSM services to ratepayers."[52]

Therefore, we do not have the expectation, or objective, that these pilots will greatly expand the base of DSM activities in California, or the potential market for ESCOs. Our commitment to tapping DSM's potential for providing reliable, least-cost

52 D.92-02-075, mimeo. p. 13.

environmentally sensitive energy services is continuing with various different efforts, as described in D.92-02-075, not the least of which is the funding expansions we have authorized for utility DSM programs since 1989.[53] Once we have had the opportunity to evaluate all of the bidding pilots initiated pursuant to PU Code § 747, we will be in a better position to determine how large the role of DSM competitive bidding should be in delivering energy services. This approach is consistent with PU Code § 747(c), which requires that we first "assess the feasibility and implications of implementing the tested bidding systems," before making recommendations on whether DSM bidding systems should be used to fulfill future electric utility resource needs. We believe that a 20 MW size for the initial pilot better serves our overall purpose for the bidding experiments, and we therefore support the ALJ's proposed program reduction in today's order.

We have, however, made one substantive change to the ALJ's proposed decision. Instead of including the 1992 costs of RFP solicitation and contract negotiation within PG&E's current DSM funding limits, we authorize $500,000 in incremental program funding for 1992. We are persuaded by PG&E's comments that, to do otherwise, would jeopardize PG&E's ability to expeditiously proceed with the pilot.

Other minor revisions and clarifications have been incorporated as necessary throughout the text of the decision.

Findings of Fact

1. On August 7, 1991, we issued the DSM OIR/OII to establish rules and procedures governing DSM activities.

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53 D.92-02-075, mimeo. Section III.

2. In the DSM OIR/OII, we direct utilities to develop and present pilot DSM bidding programs, consistent with the mandate of PU Code § 747.

3. PU Code § 747 requires that one or more energy utilities implement pilot programs to test (1) the ability of DSM bidding to deliver benefits to utility customers, separate from any generation resource bidding system; (2) the feasibility of an integrated bidding system that includes both generation resources and DSM programs; and (3) a program of competitive DSM bidding auctions for gas utilities.

4. PU Code § 747 also directs this Commission, in consultation with the CEC, to report on the results of the pilot bid projects to the Legislature by January 1, 1993.

5. In the DSM OIR/OII, we direct CACD to coordinate the evaluation of DSM bidding pilots, as required under PU Code § 747.

6. Under PG&E's proposed partnership form of bid pilot, ESCOs compete for DSM programs that augment and enhance (rather than replace) existing or planned utility DSM activities.

7. PG&E's proposed 50 MW pilot is estimated to cost between $41 and $77.5 million in NPV (1992 dollars) over the 1992-2002 program period.

8. PG&E's proposed 50 MW pilot represents an increase of 28% to 50% over PG&E's 1992 funding levels for similar DSM resource programs, not including shareholder incentives.

9. A 50 MW pilot is equal to more than half of the results of PG&E's own energy efficiency programs in 1990, and more than a third of the estimated 1991 results.

10. A 20 MW pilot is estimated to cost between $17.1 and $29.5 million in NPV (1992 dollars) over the 1992-2002 program period.

11. At this point in time, we do not know what the future competitive market in DSM will look like, or what exact role the ESCOs will play in that market.

12. PU Code § 747 requires that we first "assess the feasibility and implications of implementing the tested bidding systems," before making recommendations on whether DSM bidding should be used to fulfill future electric utility resource needs.

13. A 20 MW bidding pilot would provide sufficient testing of PG&E's partnership proposal without exposing ratepayers to excessive costs.

14. The partnership form of bid is very different from the bidding environment we have adopted for supply-side resources, and does not subject the utility to downward pressure on utility costs.

15. The partnership form of bid is not designed to be a supply-side equivalent process.

16. The partnership form of bid provides other forms of ratepayer benefits, such as information about ESCOs' ability to deliver DSM services to California customers on a reliable basis.

17. Our current bidding framework for supply-side resources does not include shareholder incentives.

18. Under the partnership bid, PG&E will be contracting out to winning ESCO bidders for the delivery of complementary DSM services in its service territory.

19. The inclusion of shareholder incentives in PG&E's partnership bid allows PG&E to remain relatively indifferent between subcontracting with ESCOs or performing the expanded DSM services itself.

20. Ratepayers' costs would be lower if PG&E's proposed pilot did not include shareholder incentives.

21. The partnership form of bid is unlikely to yield useful information if PG&E has a financial incentive to favor its own programs over those delivered by ESCOs.

22. The added costs of shareholder incentives for PG&E's pilot would not exceed approximately $5 million (1992$, NPV) for a 50 MW program; this cost would not exceed approximately $1.8 million (1992$, NPV) for a 20 MW program.

23. Under its pilot bid proposal, PG&E requests broad discretion in weighing various features of each bid against the same or different features of competing bids.

24. In D.86-07-004, we expressed reservations about a highly subjective bid evaluation process for supply-side bids.

25. By D.92-02-075, we issued rules governing the evaluation, funding, and implementation of DSM programs and associated shareholder incentives (Rules). Rule 6 states that, for programs that serve as alternatives to supply-side resources, we rely on the TRC test as the primary indicator of DSM program cost-effectiveness.

26. Under our resource procurement framework, the primary consideration in resource selection is to select the most economically efficient resource, taking environmental impacts into account.

27. The total resource cost test compares the total resource costs of DSM, including participants' costs (or customer contribution), with total resource benefits.

28. The utility cost test compares the utility's cost of DSM, excluding participants' cost, with total resource benefits.

29. In evaluating the relative cost-effectiveness of supply-side resources, we compare total resource costs and benefits.

30. Basing the ranking and funding of DSM programs on the UC test would lead to the inefficient allocation of resources, since investments would be based on an evaluation of only a portion of total costs.

31. Basing the ranking and funding of DSM programs on the UC test would be inconsistent with the evaluation methods used for supply-side resources.

32. PG&E's proposal for considering the level of customer rebates/utility costs in the bid evaluation process is highly subjective and could result in bids with higher total costs being chosen over those with lower total costs.

33. It is not clear how DRA's proposed figure of merit would assess the tradeoff between lower total costs and higher utility costs.

34. Unless the tradeoff between total costs and utility costs is made explicit, neither bidders nor evaluators will have a clear understanding of how the economic characteristics of bid proposals will be evaluated, relative to each other.

35. Stating the tradeoff between total costs and utility costs as clearly as possible would help to minimize after-the-fact controversy over scores for the economic attribute.

36. When bids are evaluated based on the TRC test, with payments based on utility costs, winning bidders could end up being paid over their bid price, unless bidders are held to their estimates of customer contribution.

37. Under its sample contract terms, PG&E requires verification of total costs, including the customers' contribution, before payments commence.

38. PG&E's RFP does not adequately describe how it plans to consider its own program costs in evaluating bid proposals.

39. The appendices to PG&E's RFP do not provide consistent total cost information for its current and planned programs.

40. Comparing bids with the costs of PG&E's own programs is similar to what we do in supply-side bidding, where the QF bids against the utility's least-cost resource addition.

41. For supply-side bids, QFs know the total costs of the resources they are bidding against, in advance.

42. The potential ESCO bidder needs to know, before committing time and resources in developing a DSM bid proposal, whether its project has any possibility of success in the bidding process.

43. When a utility's current or planned program is cost-effective, by definition its costs are lower than the avoided

supply costs that would otherwise be used in calculating the TRC for a similar program.

44. Bid proposals for DSM activities similar to PG&E's current or planned programs can be readily compared and ranked using PG&E's total program costs (including customer contribution) as the new avoided cost yardstick.

45. PG&E's partnership form of bid is not primarily designed to examine whether replacing current or planned utility DSM programs with ESCO-delivered services can reduce total resource costs.

46. Information on the total costs of a utility's current/planned programs is a critical component of the replacement or integrated form of bid, where ESCOs bid against identified utility resources.

47. Reducing the scope of the partnership pilot to 20 MW reduces the risk that ratepayers might be better off if PG&E performed expanded DSM services itself, rather than subcontracting those activities to ESCOs.

48. Our Rules governing DSM require that estimates of shareholder incentive payments be included in costs for both the TRC and UC tests of cost-effectiveness.

49. As defined in PG&E's RFP, incremental customer value represents any incremental benefit the customer receives due to the DSM program, other than the direct reduction in the PG&E bill.

50. PG&E does not currently incorporate incremental customer value in its analysis of DSM program cost-effectiveness, because PG&E does not currently have a way of determining that value effectively.

51. DRA does not currently incorporate incremental customer value in its analysis of DSM program cost-effectiveness.

52. The Standard Practice Manual working group is an appropriate forum for exploring methods to quantify incremental

customer value, for consistent use across utility-sponsored and ESCO-delivered programs.

53. The NTG ratio, or free-rider assumption, is designed to discount the value of estimated energy savings to account for customers who would have installed, solely at their own expense and without any payment from PG&E or any third party, the energy efficiency measures installed as a result of the program. The NTG also captures other factors that would reduce estimated energy savings, such as rebound effects.

54. ESCO-delivered programs may have different NTG ratios, or free rider assumptions, but those differences are difficult to evaluate on a case-by-case basis at this time.

55. Measures with very short-term paybacks are more likely to have been installed regardless of the program, i.e., they would have a higher level of free ridership (and lower NTG ratios).

56. For our initial bidding pilot, setting the NTG ratio at 1.0 for programs with greater than a two-year payback represents a reasonable accommodation of parties' concerns that the NTG ratios adopted for PG&E's programs may be too low for certain types of ESCO-delivered programs.

57. Under PG&E's proposal for the treatment of administrative costs, ratepayers would pay the cost of all utility administrative services required by the winning bidders.

58. In evaluating partnership bids, PG&E proposes to assume a uniform 10% (of bid price) in utility administrative costs, across all proposals.

59. PG&E's proposal for considering administrative costs would penalize ESCOs requiring less administrative oversight or involvement from the utility, relative to ESCOs requiring more oversight/involvement, all other things being equal.

60. Administrative costs associated with bid evaluation/ negotiations with QFs or other utilities are considered part of

general contract administration costs, and are generally borne by ratepayers.

61. Training of PG&E market representatives to assist ESCOs in their marketing efforts, providing customer energy usage information, producing publicity literature and other project-related administrative costs are integral to the ESCO's DSM program and delivery of energy savings.

62. Other states require project-specific administrative costs to be included in the ESCO bid price or reimbursable to the utility.

63. PG&E's evaluation of the economic attribute may not identify the least-cost providers of DSM services, if ESCO bid prices do not reflect the full cost of achieving program savings, including utility administrative services.

64. PU Code § 701.1(c) directs this Commission to include a value for any costs and benefits to the environment in calculating the cost-effectiveness of energy resources, including conservation and load management.

65. In our adopted Rules, we direct respondents to use avoided costs and nonprice (e.g., environmental) values that are consistent with the values developed in the Update.

66. Following the issuance of a final decision in the current phase of the Update, CACD will conduct workshops on how to translate Update findings into avoided costs for DSM cost-effectiveness testing. CACD's report on these workshops is due by November 1, 1992 (per D.92-02-075).

67. Requiring PG&E to develop avoided costs that are in compliance with the Update findings would significantly delay the RFP process.

68. PG&E currently has considerable discretion to modify or augment its authorized DSM activities both within and across program categories.

69. A Commission order in PG&E's GRC proceeding, including the types of new or expanded DSM programs PG&E should undertake, may not be issued prior to bid selection under PG&E's bidding pilot.

70. DRA's proposal to disquality limited product bidders would preclude a customer from bidding for measures on its own site, or any ESCO from focusing on a particular market sector.

71. PG&E's emphasis on bids which avoid lost opportunities, either through comprehensive approaches or by focusing on specific lost-opportunity resources, is consistent with our proposed Rules.

72. A tiered pricing system, where the bidder offers different prices for increasing levels of achieved savings, may encourage the winning bidder to pursue lost opportunities, without increasing the overall cost of the program.

73. Rule 16 of our adopted Rules includes load management programs that promote energy efficiency as eligible for shareholder incentives.

74. Rule 16 of our adopted Rules specifically states that fuel substitution programs should not be eligible for shareholder incentives, pending resolution of technical issues associated with assessing the benefits of these programs.

75. Directing PG&E to develop and use standardized software to measure ESCO-delivered savings under this pilot would be premature, given the wide range of approaches and computer programs available to evaluate DSM savings.

76. The DSM Rulemaking and companion Investigation is the appropriate forum for developing more standardization and uniformity in measuring DSM savings, for both ESCO- and utility-delivered programs.

77. Using existing equipment as the baseline reference for calculating energy savings may overestimate measured savings, since much of the equipment available today is subject to minimum state or federal efficiency standards.

78. PG&E's proposed weighting process gives the economic attribute the highest weight, with the measurement/verification plan following second.

79. PG&E's RFP does not specifically describe how bids will be assigned scores within each attribute, and how scores will be put on a comparable basis across attributes.

80. Front-loading provides for payments to ESCOs above avoided costs during the early years of the contract, with payments declining over time.

81. In the past, we have allowed some front-loading in QF payments, coupled with security provisions that ensure the QF returns overpayments if it ceases operation before the end of the contract.

82. For QF contracts that allow front-loading of energy payments (i.e., Interim Standard Offer 4), we require upfront security provisions similar to the ones proposed by PG&E for its DSM bidding pilot.

83. PG&E's proposed upfront security provisions allow the ESCO to choose from several different options, including a letter of credit, performance bond, or corporate guarantee.

84. As proposed, PG&E's project completion date provisions result in differing completion periods, depending on certain contingencies.

85. The maximum period allowed for project completion under PG&E's proposed sample contract is 36 months.

86. As proposed, all aspects of PG&E's sample contract (Ex. 6) are subject to negotiations; however, bid price would be negotiable only in response to an alteration in some other aspect of the bid.

87. The partnership form of bid effectively expands PG&E's DSM activities (via ESCO subcontracting) and its shareholders' potential for earnings.

88. Until the pilot bid is complete, we will not know which market sectors or types of programs the ESCOs will compete for to provide, effectively, subcontracting services for expanded DSM services.

89. The GRC proceeding is conducted under a rate case plan with specific time constraints.

90. It is impractical to direct PG&E to subcontract out a portion of its planned program expansions proposed in the GRC to ESCOs under this partnership bid.

91. PG&E proposes to treat this bidding pilot as an added component of its resource programs, which will require incorporating minimum performance goals for this pilot into revised goals for all of PG&E's resource programs.

92. PG&E is currently authorized to exceed its total resource program budget by 130%, and spend up to 150% of any given resource program's budget.

93. There is some uncertainty over when contract payments will actually commence during the 1993-1995 program implementation period.

94. Standard offer contracts represent boiler-plate forms which become effective contracts when signed by the third-party energy service provider.

95. Payments made under standard offers are automatically recovered in rates, i.e., the reasonableness of contract payments are not later evaluated in reasonableness reviews.

96. Standard offer contracts were developed for QFs after extensive review of terms and provisions in a consolidated proceeding.

97. PG&E's sample contract was presented and evaluated as a starting point for negotiations, and was given only cursory review by most parties.

98. The modifications to PG&E's RFP, as required by this order, will make the bid evaluation process more objective, thus reducing the number of disputes over bid selection.

99. Our current complaint procedures are available to all ESCOs, as they have been to QFs for resolving bid selection or negotiation disputes.

100. SCE filed its Opening Brief one day late, but sent copies to the key parties via overnight mail.

Conclusions of Law

1. Reducing PG&E's bidding pilot to a maximum of 20 MW would better serve our overall purpose for the bidding experiments and the objectives of PU Code § 747.

2. The partnership approach is a reasonable form of bid for PG&E's pilot bidding program.

3. Any final determinations on the preferred form of bid should await our evaluation of the pilot bidding programs.

4. As long as the purpose of PG&E's pilot is to test the ability of ESCOs to deliver reliable savings in a subcontracting/partnership mode (and not as competitors), it is reasonable to include the pilot within the subset of DSM programs that are currently eligible for shareholder incentives.

5. Our decision today to include shareholder incentives is unique to the form, size and ratepayer impacts of PG&E's bidding pilot and should not be viewed as precedential for other bidding forms or proposed bidding pilots.

6. On an experimental basis, it is reasonable to proceed with PG&E's bid evaluation proposal, provided that certain aspects of the ranking and weighting criteria are made more objective and transparent.

7. PG&E should eliminate the RFP language which permits PG&E to alter the relative weights of its selection criteria after bids are received.

8. Bid proposals should be ranked based on the TRC test, for the purpose of establishing a score under the economic attribute.

9. The relative level of utility costs associated with each bid proposal should not reverse the ranking of bids based on the TRC test; rather, the UC test should be used as a tie-breaker, as described in this order.

10. PG&E's contribution to bidder payments should be reduced commensurately if actual customer contributions exceed the estimates presented in the bid proposal.

11. For this pilot program, it is reasonable to condition the consideration of PG&E's current or planned program costs in the bid selection process on the availability of total cost information in advance of the bid.

12. If PG&E can provide bidders with TRC information for its current and planned programs in advance of this pilot bid, PG&E should consider that information in ranking bid proposals, using the procedures outlined in this order.

13. If PG&E is unable to provide the required TRC information in advance of the bid, PG&E should not consider its current or planned program costs in evaluating partnership bid proposals under this pilot program.

14. PG&E should include estimates of shareholder incentive payments in costs for both the TRC and UC tests of cost-effectiveness.

15. PG&E should modify its RFP to make the description of the economic attribute consistent with this order. Other than the tests of cost-effectiveness described in this order, no other factors or criteria should be considered in evaluating proposals under the economic attribute.

16. PG&E should exclude consideration of incremental customer value for its bidding pilot.

17. Future efforts to incorporate incremental customer value into DSM cost-effectiveness tests should focus on readily

identified and quantified costs, such as avoided equipment replacement costs.

18. For this bidding pilot, PG&E should set the NTG ratio at 1.0 for programs with greater than a two-year payback. The default NTGs should be set consistent with PG&E's current program measures, i.e., 0.7 for all CIA measures, measure-specific values for identified residential measures in Ex. 11, and 0.7 default for other residential measures.

19. As part of its RFP, PG&E should provide bidders with a menu of administrative functions and their approximate costs. In their response packages, bidders should specify which, if any, of those functions: (1) they do not want performed at all; (2) they intend to perform themselves at their cost; and (3) they want PG&E to perform for which they will reimburse PG&E.

20. In evaluating bid proposals under this pilot, PG&E should use avoided costs that are consistent with the avoided costs PG&E proposes to use to evaluate its own DSM programs in the 1993 GRC.

21. Once we have considered CACD's workshop report on Update/DSM consistency issues and made our determinations on how to use Update findings to evaluate DSM program cost-effectiveness, those determinations should be used for all subsequent applications of the Standard Practice Manual tests, including this bidding pilot.

22. An ESCO bid should not be considered incompatible with PG&E's programs unless it requires PG&E to discontinue an existing program providing the same measures to the same customers at lower total costs.

23. Limited product bidders should be allowed to bid in PG&E's pilot.

24. In addition to the evaluation criteria described in Ex. 2, Section K., bidders who bid tiered prices should be given favorable consideration under the comprehensiveness attribute.

25. Bidders sponsoring programs that rely on behavioral changes should include appropriate measurement plans for verifying program savings.

26. Fuel substitution programs should not be eligible to bid in PG&E's pilot bidding program.

27. Load management programs that promote energy efficiency (as opposed to load building or load retention programs) should be eligible to bid in PG&E's bidding pilot.

28. Allowing bidders to propose their own measurement and verification programs, subject to PG&E's case-by-case evaluation, is a reasonable approach for this bidding pilot.

29. The baseline reference for calculating energy savings in pre- and post-installation measurement should be the minimum standards equipment, not existing equipment.

30. PG&E's proposed weights for bid evaluation attributes are reasonable for this experimental program.

31. Further fine tuning of the weighting scheme, as well as other aspects of the bid evaluation process, should be considered as part of CACD's overall evaluation of the pilot bidding programs.

32. PG&E's RPP should describe more specifically how bids will be assigned scores within each attribute, and how scores will be put on a comparable basis across attributes, as suggested by SESCO.

33. At the time PG&E announces its short list of bid proposals, PG&E should make available summaries of project proposals and a final ranking with associated scores for each attribute. This information should be sent to all bidders and anyone else requesting a copy.

34. For the purpose of this bidding pilot, PG&E's upfront security provisions (for front-loaded payments) are reasonable.

35. PG&E should modify its sample contract to allow for a uniform 36 months for project completion, following Commission approval of the contract.

36. It is reasonable for PG&E to request the sample contract with proposed changes in bidders' response packages; however, PG&E's evaluation process should only consider the attributes described in the RFP, as modified by this order.

37. It is reasonable to authorize in today's order incremental funding for PG&E's partnership bid, at a 20 MW level, for program expenditures over the 1992-1995 period.

38. Beyond 1995, PG&E should request specific funding for this pilot in the appropriate rate case.

39. Expenditures for PG&E's DSM bidding pilot should be included in the existing two-way balancing accounts for other PG&E resource DSM programs, i.e., the CEERPBA.

40. PG&E should not shift funds from the bidding pilot to its other resource programs.

41. PG&E should incorporate minimum performance goals for this 20 MW pilot into revised goals for all of PG&E's resource programs.

42. Our decision today to authorize incremental funding for PG&E's DSM bidding pilot should be taken into consideration when we evaluate PG&E's overall DSM funding request in its test year 1993 GRC.

43. For the purpose of this bidding pilot, it is not reasonable to consider PG&E's sample contract, as presented in Exhibit 6, as a standard offer contract for ESCOs.

44. The Commission should review the reasonableness of negotiated contracts, and associated payments, between PG&E and winning bidders either: 1) in ECAC reasonableness reviews or 2) upon application by PG&E for contract preapproval.

45. Should PG&E decide to submit some or all of the contracts for preapproval, PG&E should submit them all at the same time, rather than one-by-one as they are signed, and provide the cost and comparative information described in this order.

46. A separate appeals process for this pilot bidding program is unnecessary.

47. In its evaluation of the DSM bidding pilots, pursuant to PU Code § 747, CACD should evaluate how the adopted weighting scheme for the economic and comprehensiveness attributes affects the selection of bids that are designed to avoid lost opportunities.

48. In its evaluation of the DSM bidding pilots, pursuant to PU Code § 747, CACD should assess whether bid selection or negotiation disputes can be minimized through alternative program design, and whether an alternative appeals process is appropriate.

49. Since no party was prejudiced by the one-day late filing of SCE's Opening Brief or SESCO's late-filed Comments, SCE's and SESCO's requests for extensions of time are reasonable and should be granted.

50. In order to proceed as expeditiously as possible with PG&E's bidding pilot, this order should be effective today.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company's request for an extension of time to file its opening brief is granted.

2. SESCO, Inc.'s request for an extension to file comments on the proposed decision of the Administrative Law Judge is granted.

3. Pacific Gas and Electric Company (PG&E) is authorized to conduct its proposed Demand-Side Management (DSM) pilot bidding program, as modified by this order.

4. PG&E's DSM pilot bidding program shall not exceed 20 Megawatts (MW).

5. PG&E is authorized to increase its Customer Energy Efficiency Resource Program Balancing Account revenue requirement by $500,000 to cover DSM pilot bidding expenditures for 1992.

6. PG&E is authorized to increase its Customer Energy Efficiency Resource Program Balancing Account revenue requirement by a total of $17.5 million (in 1992 dollars) to cover DSM pilot bidding expenditures for 1993, 1994, and 1995.

7. The 1993-1995 revenue requirement adopted in this order shall be consolidated with that of PG&E's current general rate case, Application (A.) 91-11-036, for the purposes of revenue allocation and rate design. PG&E shall collect funding for the 1992 revenue requirement adopted by this order in its current general rate case or next Energy Cost Adjustment Clause proceeding.

8. Beyond 1995, PG&E shall request specific funding for its DSM bidding pilot in the appropriate general rate case.

9. PG&E is prohibited from shifting funds from the pilot bidding program to other resource programs.

10. The reasonableness of contract payments made under PG&E's DSM bidding pilot shall be determined in either subsequent reasonableness reviews or upon PG&E's application for Commission preapproval.

11. Should PG&E decide to submit some or all of the individual contracts for Commission preapproval, PG&E shall:

- Request preapproval of the contract payments by application, with service on all parties to this proceeding.
- Submit all of the contracts for preapproval at the same time, or, if a selected number of contracts require more time for negotiations, in two groupings.
- As part of its application for preapproval, provide information on the cost impacts of each negotiated contract (i.e., by comparing year-by-year total project costs under the contract with long-run avoided costs) and provide a comparison of the similarities and

differences among the negotiated contracts, with respect to specific contract provisions.

12. Within 60 days from the effective date of this order, PG&E shall file a revised request for proposals, including appendices, response package, and sample contract in conformance with the modifications made by this order. Comments on PG&E's compliance filings shall be filed within 90 days from the effective date of this order. PG&E's compliance filings and interested parties' comments shall be filed with the Commission's Docket Office and served on all appearances and the state service list in these proceedings.

13. Within 15 days from the effective date of this order, PG&E shall file comments on a schedule and procedural forum for incorporating minimum performance goals for its 20 MW bidding pilot into revised goals for all of its resource programs. Reply comments shall be filed within 30 days from the effective date of this order. Comments shall be filed at the Commission's Docket Office, and served on all parties to these proceedings and A.91-11-036.

This order is effective today.

Dated March 11, 1992, at San Francisco, California.

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

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

NEAL J. SHULMAN, Executive Director

TABLE OF ACRONYMS AND ABBREVIATIONS

A.	Application
ALJ	Administrative Law Judge
CACD	Commission Advisory and Compliance Division
CEC	California Energy Commission
CEERPBA	Customer Energy Efficiency Resource Program Balancing Account
CERT	Coalition of Energy Efficiency and Renewable Technologies
CIA	commercial, industrial, and agricultural
D.	Decision
DRA	Division of Ratepayer Advocates
DSM	Demand-Side Management
DSM OIR/OII	DSM Order Instituting Rulemaking/ Order Instituting Investigation
ECAC	energy cost adjustment clause
ERA	Energy & Resource Advocates, Inc.
ESCOs	energy service companies
Ex.	Exhibit
GRC	general rate case
M&V	measurement and verification
MW	megawatts
NAESCO	National Association of Energy Service Companies
NPV	net present value
NRDC	Natural Resources Defense Council

NTG	net-to-gross
PG&E	Pacific Gas and Electric Company
PU Code	Public Utilities Code
QFs	qualifying facilities
RFP	Request For Proposals
Rules	rules for DSM, as adopted in D.92-02-075
SCE	Southern California Edison Company
SESCO	SESCO, Inc.
TR	Reporters' Transcript
Transphase	Transphase, Inc.
TRC	Total Resource Cost
UC	Utility Cost
Update	Biennial Resource Plan Update (I.89-07-004)

(END OF ATTACHMENT 1)

ATTACHMENT 1
Page 1

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ATTACHMENT 2

List of Appearances

Respondents: David R. Clark and J. F. Walsh, Attorneys at Law, and Y. A. Whiting, for San Diego Gas & Electric Company; Robert B. Keeler, Attorney at Law, for Southern California Gas Company; Robert B. McLennan, Attorney at Law, for Pacific Gas and Electric Company; and Stephen E. Pickett, Frank J. Cooley, and Gene E. Rodrigues, Attorneys at Law, for Southern California Edison Company.

Interested Parties: C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Barbara Barkovich, for Barkovich and Yap; Ralph Cavanagh, Attorney at Law, for Natural Resource Defense Counsel; Steven F. Greenwald and Andrea B. Colace, Attorneys at Law, for Skadden, Arps, Slate, Meagher & Flom; Norman J. Furuta, Attorney at Law, for Federal Executive Agencies; Grueneich, Ellison & Schneider, by Dian M. Grueneich, Attorney at Law, for California Department of General Services and South Coast Air Quality Management District; James Hodges, for The East Los Angeles Community Union; Caryn Hough, Attorney at Law, for California Energy Commission; Lon W. House, for Henwood Energy Services; Phyllis Huckabee, for El Paso Natural Gas Company; Douglas K. Kerner, Attorney at Law, for Roberts & Kerner; Audrie Krause, K. Justin Reidhead, Michel Peter Florio, and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Martin A. Mattes and Diane I. Fellman, Attorneys at Law, for Graham & James; Daniel Meek, Attorney at Law, for SESCO, Inc.; Melissa Metzler, for Barakat & Chamberlin; David L. Modisette, for Edson & Modisette; Sara Steck Myers, Attorney at Law, for Coalition for Energy Efficiency and Renewable Technologies; Bronson, Bronson & Mc Kinnon, by Scott W. Pink, Attorney at Law, for Transphase Systems, Inc.; John D. Quinley, for Cogeneration Service Bureau; John W. Witt, City Attorney, by William S. Shaffran and Deborah Berger, Deputy City Attorneys, for the City of San Diego; Andrew Brown and Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers Association; Jackson, Tufts, Cole & Black, by William H. Booth, Joseph Faber and Allan Thompson, Attorneys at Law, for California Large Energy Consumers Association; James Adams, for Energy & Resource Associates; Robert I. Burt, for California Manufacturers Association; and Charles Goldman and Patrick L. Splitt, for themselves.

Division of Ratepayer Advocates: Irene K. Moosen, Attorney at Law.

(END OF ATTACHMENT 2)