Decision ______________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	Rulemaking 02-06-001 (Filed June 6, 2002)

INTERIM OPINION IN PHASE 1 ADDRESSING DEMAND RESPONSE GOALS AND ADOPTING TARIFFS AND PROGRAMS FOR LARGE CUSTOMERS

INTERIM OPINION IN PHASE 1 ADDRESSING DEMAND RESPONSE GOALS AND ADOPTING TARIFFS AND PROGRAMS FOR LARGE CUSTOMERS........1
I. Summary 2
II. Background 2
III. Statewide Demand Response Vision and Goals 7
IV. Demand Response Programs For Large Customers.................................11
A. This Decision in Context: The Challenge of Developing Demand Response Programs for Large Customers 11
B. Design Objectives for Demand Response Programs..................................14
C. Mandatory or Voluntary Participation? 15
D. Program Details 17
1. Dynamic Pricing Proposals 18
2. Demand Bidding Programs...27
3. Pilot Programs 34
E. Customer Participation Issues 37
1. Agricultural Customers 37
2. Multiple Meter Situations...39
3. Multiple Program Participation...40
4. Transitional Incentives 44
F. Expected Impacts 53
G. Program Duration 53
H. Elimination of Superfluous Programs and Tariffs......................................54
I. Program Costs and Related Cost Issues...55
1. Cost-Effectiveness 55
Program/Tariff...56
2. The Principle of Revenue Neutrality and Recovery of Revenue Shortfalls...57
3. Program Administrative Costs 60
4. Capital Costs 61
5. The Costs of Incentives 61
6. Imposition of Cost Cap 62
7. Cost Recovery Mechanisms...62
J. Customer Education/Outreach...62
K. Program Evaluation, Monitoring and Oversight 64
V. Phase 2 of this Rulemaking...67
VI. Comments on Draft Decision...67
A. Revisions: Program Details 68
B. Revisions: Customer Participation Issues..68
C. Revisions: Program Costs and Related Cost Issues 69
D. Revisions: Program Evaluation and Monitoring Oversight.......................69

VII. Assignment of Proceeding....69
Findings of Fact....70
Conclusions of Law....79
ORDER....83

Attachment A
Attachment B
Attachment C
Attachment D
Attachment E

I. Summary

This decision, the second of two decisions to be rendered in Phase 1 of this demand response rulemaking, addresses the interagency vision for advancing statewide demand response goals, links the task of meeting those goals with utility procurement requirements, and adopts an initial set of voluntary tariffs and programs for large customers whose electricity use exceeds 200 kW per month. The decision also sets annual megawatt (MW) targets to be met through demand response and included in investor-owned utility (IOU) procurement plans.

The approved offerings for large customers include a statewide Critical Peak Pricing (CPP) tariff, an Hourly Pricing Option (HPO) tariff for customers in San Diego Gas & Electric's (SDG&E) territory, an IOU demand bidding program (DBP), and the Demand Reserves Program (DRP) offered under the aegis of the California Consumer Power and Conservation Financing Authority (CPA). While these offerings have no expiration date, we authorize funding for 2003 and 2004, capping expected costs at $33.0 million over the two years. The respondent IOUs are required to file tariffs and implementation plans for the approaches we adopt.

II. Background

Decision (D.) 03-03-036[1], our Interim Opinion in Phase 1 Adopting a Pilot Program for Residential and Small Commercial Customers, details much of the history of this rulemaking. We do not repeat that discussion here, except to highlight several key points.

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[1] D.03-03-036 was issued March 14, 2003.

We began this rulemaking[2] in June 2002, as a policymaking forum to develop demand response as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. At the outset we recognized the need for a strategic approach to the orderly development of demand response capability in the California energy market. To that end, we have coordinated this rulemaking exercise with decision makers from the California Energy Commission (CEC) and the CPA based on an interagency working model developed by the assigned Commissioner.[3]

That model relied upon three working groups. Of particular significance to this decision are the efforts of Working Group 1 (WG1) and Working Group 2 (WG2).[4] WG1 is comprised of agency decision makers (assigned Commissioner Michael Peevey, CEC Commissioner Arthur Rosenfeld, and CPA Director Sunne W. McPeak, also known as the "Working Group 1 principals"), supported by the assigned ALJ and advisory staff from the CPUC, CEC and CPA, and has been responsible for shaping the rulemaking record and providing policy guidance to the parties throughout the proceeding. WG 2 is comprised of active parties who are interested in developing demand response approaches for large customers. It represents a diversity of interests, including the investor owned utilities,

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[2] The Commission's rulemaking named as respondents the following investor owned utilities (IOUs): Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison Company (Edison), though the rulemaking may be expanded in the future to include other small and multi-jurisdictional IOUs.

[3] See, Ruling Following Prehearing Conference, dated August 1, 2002; and Assigned Commissioner's Ruling and Scoping Memo, dated August 16, 2002.

[4] The third group, Working Group 3 (WG3) is comprised of active parties who are interested in developing demand response programs for small commercial and residential customers.

municipal utilities, ratepayer advocates, large customer associations, various demand response vendors and consultants, energy service providers, utility workers, and the California Independent System Operator (ISO). This group, whose meetings were facilitated by agency staff supporting WG1, has developed the specific proposals we consider here.

As this decision recognizes, a robust and sound policy framework is essential as the foundation for the future development of statewide demand response programs. At the same time, the WG1 principals appreciate the need for swift action to take advantage of the real opportunity to achieve significant levels of demand reduction by Summer 2003. Balancing these factors, WG1 directed WG2 to delve into the practicalities of program and tariff development for large customers, rather than pursue additional pilot programs for such customers in Phase 1, and formalized WG2's mission as "expanding demand response capabilities by developing a tariff or set of tariffs to be used for large customers with average monthly demands of 200 kW and above."[5]

WG 1, meanwhile, focused its efforts on the development of a long-term vision for the development of demand responsiveness in California by setting a framework, developing goals, and focusing on how demand response can and should be integrated with the IOUs' overall procurement responsibilities.

All working group meetings were publicly noticed and meeting agendas were publicly available at least 48 hours prior to each meeting. The WG2 facilitators made meeting minutes available to all participants.[6] At the WG2

[5] August 1, 2002 Ruling Following Prehearing Conference, page 4.

[6] Ground rules for working group discussions were specified in the ALJ's August 1, 2002 ruling, page 4.

meetings, the facilitators encouraged broad participation in an environment where stakeholders representing a variety of views were free to provide their opinions, make proposals and presentations, share their practical experiences, and work toward collective solutions. The group's initial focus was on taking advantage of the advanced meters already installed at customer sites with monthly demands of more than 200 kW, paid for through appropriations in Assembly Bill 29 of the First Extraordinary Session of 2000-2001 (AB29X) (Stats. 2001, 1st Ex. Sess., Ch. 8, Sec. 10.2, effective April 12, 2001). The participants attempted to develop consensus around a set of "quick win" dynamic pricing proposals designed to take advantage of these existing meters and produce demand response by the Summer of 2003, but the diversity of opinion on key issues complicated this task and ultimately worked against the development of consensus.

Several parties have participated actively in the workshop process and have filed written comments on WG2 issues throughout Phase 1. These include respondents PG&E, SDG&E, and Edison (the "respondent IOUs"); the Office of Ratepayer Advocates (ORA); The Utility Reform Network (TURN); the California Consumer Empowerment Alliance (CCEA); the City and County of San Francisco (CCSF); the Department of General Services (DGS); the Alliance for Retail Energy Markets and the Western Power Trading Forum (AreM and WPTF); the Association of California Water Agencies (ACWA); the Building Owners and Managers Association of California (BOMA); the California Large Energy Consumers Association (CLECA); the California Manufacturers & Technology Association (CMTA); the Demand Reserves Providers (Ancillary Services Coalition; Celebrity Energy; DBS Industries; Robertson-Bryan, Inc.); and IMServ.

Working Group 2 has filed four reports. The first, filed on November 15, 2002, contained six demand response offerings (four tariffs and two programs) to be implemented by Summer 2003. The second report, filed on December 13, 2002, supplemented the first by addressing implementation details.[7] After the WG1 principals expressed concern that the proposed offerings were inadequate to meet WG1's demand response goals,[8] the respondent IOUs significantly revised their proposals, and withdrew some of those proffered earlier. As a result, on January 16, 2003, WG2 filed its third report containing a proposal sponsored by the respondent IOUs for a statewide critical peak pricing (CPP) tariff. On January 27, 2003, the active parties filed written comments addressing all of the third report and those elements of the first two reports not superseded by the third filing. Since agency staff suggested incentives might be needed to achieve the quantitative goals proposed for demand response programs, the ALJ permitted WG2 to hold another noticed workshop focused on transitional incentives, and on March 11, 2003, WG2 presented its fourth and final report addressing this limited issue.[9] The record in Phase 1 with respect to WG2 issues

[7] On December 23, 2002, WG2 filed an Errata to both the November 15 and December 13 Reports.

[8] See generally WS-4 RT 284-372, the official transcript of the December 4, 2002 meeting of Working Group 1.

[9] In lieu of individually filed written comments, the parties included their comments, both supporting and dissenting, in the body of the fourth WG2 Report.

was then submitted. By that time, the WG1 principals had held five noticed workshop meetings,[10] and WG 2 had held thirteen noticed workshop meetings.[11]

The Commission has held no hearings in Phase 1, but has proceeded via notice and comment rulemaking, with WG1 providing specific policy guidance to the active parties at key points through formally noticed meetings and rulings. Following this direction, and working through WG1 staff facilitators, the parties developed the proposals we address in Phase 1. Our decision making record in connection with WG2 issues consists of respondents' formal demand response programs/pricing options filed in compliance with the OIR; the official transcripts of five formally noticed WG1 meetings; the rulings following those meetings and written comments thereon; and the four WG2 reports and related rulings and written comments.

III. Statewide Demand Response Vision and Goals

Early on during WG1 meetings, the Principals endorsed the idea of developing a long-term "vision" and set of goals for demand response to help guide the efforts of participants in this proceeding. The aim was not to prejudge issues but instead to provide a framework and set of goals within the context of which activities in this proceeding would be set. Interagency staff supporting WG1 set out to develop this vision. An initial presentation was made during the

[10] WG1 met on August 26, September 16, October 15, December 4, 2002, and February 7, 2003. These meetings were officially transcribed (See WS-1 RT 1-100; WS-2 RT 101-201; WS-3 RT202-283; WS-4 RT 284-372; WS-5 RT 373-444).

[11] WG2 met on September 18, 26, October 2, 11, 17, 23, November 1, 12, 19, December 3, 10, 2002, January 10, and February 26, 2003. On February 7, 2003, at Commissioner Rosenfeld's request, members of WG2 met informally to discuss transitional incentives.

WG1 meeting of September 16, 2002[12] with follow-up discussions during the October 15 and December 4 WG1 meetings. Revisions were made to an evolving vision statement after each WG1 meeting, and parties were asked to comment on each version in response to rulings following each WG1 meeting. Thus, there were three rounds of comment opportunities on the vision statement.[13] Numerous changes were made to the original vision statement as a result of those comments. The most current version of the vision statement is attached to this decision as Attachment A.

The vision statement provides a definition and simple statement of a goal, followed by objectives (reliability, lower power costs, and environmental protection), goals and principles (customer service, optionality, technology issues, IOU issues, coordination) and a timeframe (phases for proof-of-concept, phased implementation for large customers, and residential implementation).

While we do not seek formal Commission adoption of the entire vision statement in this decision, since we view it as an evolving document and work-in-progress at all times, there are several aspects of the vision that we do believe require explicit Commission endorsement in order to help direct the activities of IOUs and other parties.

In particular, since the vision statement sets a goal of meeting IOU capacity needs of five percent of system peak demand by 2007 through demand

[12] See presentation by John Flory attached to the transcript of the September 16, 2002 WG1 meeting.

[13] During the original round of comments prompted by the October 29 ALJ ruling, comments were filed by PG&E, TURN, ORA, CFBF, CIU, CLECA, NRDC, Invensys, Alliance to Save Energy / SVMG / CCEA, SCE, and SDG&E.

response,[14] we believe it is important to set interim megawatt (MW) targets in pursuit of that goal. We also wish to make explicit the linkage between these targets and the utilities' procurement-related obligations to be included in their procurement plans to be filed in R.01-10-024.

In order to facilitate the setting of concrete goals for demand response, during the February 7, 2003 meeting of WG1, interagency staff presented a set of proposed targets. These represent roughly an increase in 1% of demand response achieved between 2003 and 2007, and are summarized in the table below.

Table 1. Demand response goals

Year	**PG&E**	**Edison**	**SDG&E**
2003	150 MW	150 MW	30 MW
2004	400 MW	400 MW	80 MW
2005	3% of the annual system peak demand		
2006	4% of the annual system peak demand		
2007	5% of the annual system peak demand		

In their verbal comments at the February 7 WG1 meeting, the utilities responded that these targets could be a stretch, but are achievable.[15] Interagency staff further recommended that the utilities be required to include these targets in their procurement plans to be filed in R.01-10-024. To the extent that this

[14] This goal does not include (is over and above) demand response achieved through the emergency programs authorized in R.00-10-002 (interruptible rulemaking). Thus, in this decision we are referring to programs and tariffs that are triggered by price and not by emergency conditions.

[15] See transcript of February 7, 2003 WG1 meeting (5 WS RT 426, 430).

decision is adopted after those plans are filed, the utilities should supplement or augment their filings to reflect this requirement. In particular, each utility should include the numeric targets given in the table above, along with documentation of:

- The amount of demand response (price-triggered) to be achieved by July 1 of each calendar year
- Which programs and/or tariffs the utility will rely upon to achieve the targets
- A contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals

This means that the utilities should not contract for the equivalent amounts of generation resources and should instead rely upon demand response resources to serve load. Utilities should dispatch the tariffs and programs when they are cost-effective relative to the marginal generation costs avoidable through demand response as the utilities make short-run commitments. To the extent that the actual reliable demand response resources fall short of the goals, the utilities should be allowed and able to supplement their short-term purchases.

We expect that during the early years, most of the demand response goals will be met by programs and tariffs for large customers, such as those we authorize in the following sections of this decision. Based on the outcome of the pilot for small customers we authorized in D.03-03-036, the utilities should eventually be able to meet more of their goals reliably through programs and tariffs for smaller customers, including air-conditioner cycling programs which we will address in phase 2 of this proceeding.

Thus, we explicitly link the tariffs and programs being developed on an ongoing basis in this proceeding with procurement planning in R.01-10-024. While in R.01-10-024 utilities will estimate their resource needs and how those needs will be met from which type of resource, in this proceeding we will continue to focus our attention on how to meet those needs through various programmatic and tariff approaches. In this early stage, we will authorize specific budget expenditures for demand response programs in this proceeding (and in this decision).

IV.Demand Response Programs For Large Customers

A. This Decision in Context: The Challenge of Developing Demand Response Programs for Large Customers

Throughout this rulemaking we have stressed the importance of the policymaking vision and goals that serve as the foundation for building demand response programs that are sustainable over the long term. At the outset we noted that a perfectly functioning wholesale and/or retail electricity market was not a precondition for development of demand response, and we explicitly stated the value of demand response as "…a tool in mitigating the effects of a dysfunctional market, as well as for controlling costs, even in a completely vertically integrated and regulated market."[16] However, adding this tool to our regulatory tool chest is not an easy task, and will require an iterative process as well as a multi-year commitment on the part of regulators, customers and utilities that involves the following: taking care to develop the programs that are workable and suitable for their intended purpose; listening to what the members of different customer classes tell us about their needs both explicitly and by their

[16] Order Instituting Rulemaking (R.02-06-001), p. 1.

reaction to the programs we adopt; and both fine tuning and significantly adjusting these programs over the years, in a manner consistent with the need for stability in these programs. We cannot accomplish everything on our policy agenda in one decision, or even in a series of decisions. Instead, we must take the long-term view, even as we begin with a series of discrete steps. The challenges posed by large customer demand response are daunting and quite complex, requiring that we proceed deliberately, but with great care.

Although the WG2 participants agree on many principles, they have been unable to develop a consensus tariff proposal, given the diversity of views among large customer interests, respondents, and the other parties. As one party characterizes the situation, "to date, customer support for utility designed programs has been tepid, and utility support for third party proposals has been nonexistent."[17]

It is clear that large customers use electricity in ways that differ fundamentally from the ways in which other customers use it. For example, their electricity usage may be an essential component of an industrial or agricultural process. This means that as they consider load shifting or load reduction, such customers must also consider distinct and significant cost issues relative to their operating requirements, whether they be manufacturers, agricultural users, or building owners.[18] All of these factors require us to make a careful assessment of the impacts of our decisions on these customers.

[17] CMTA's Comments on WG2 Reports, p. 2.

[18] See, e.g., the following parties' comments on the various WG2 Reports: ACWA; BOMA; CLECA; and CMTA.

In retrospect, our focus on achieving a "quick win" may have made it more difficult for these customers to find common ground. At the outset, we encouraged the parties to focus on tariffs / programs that would achieve a "quick win" because we wanted to take advantage of the fact that many >200 kW customers already have advanced meters in place (due to AB29X) in order to learn how such customers would react to dynamic tariffs during Summer '03 and Summer '04, when system conditions for such a test should be ideal. However, we now know that some parties were reluctant to consider third party proposals, such as an innovative two- part RTP tariff, due to concern that such proposals could not be in place within a matter of months.[19] As a result, in Phase 1 we address a relatively limited number of demand response options. However, as we shift focus beyond 2003, we will confront some of the structural and regulatory obstacles that may be impeding customer acceptance of demand response programs, and we will carefully refine our initial efforts and design new programs that will garner long-term customer support.

For now, this decision considers the merits of adopting CPP tariffs and a limited RTP tariff presented by SDG&E, as well as demand bidding programs – and the authorization of funding for these tariffs and programs through 2004. As these tariffs and programs will be in place well beyond 2004, our goal is to encourage as many large customers as possible to participate in them as a first step in a longer-term effort. This first step also involves careful recruitment and encouragement of participating customers, using modest incentives in the near term. The customers who participate in the tariffs / programs adopted in this

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[19] CMTA's Comments on WG2 Reports, pp. 3 – 4.

decision are the vanguard of the customers who will participate in demand response programs during the coming years.

B. Design Objectives for Demand Response Programs

In its November 15th report, WG2 developed several design objectives that take into account the fact that no single program satisfies all large commercial customers.[20] Some customers can use demand bidding programs to bid load reductions into the day ahead market, thus providing the electric system with an alternative source of supply. Other customers can reduce or shift their usage in response to posted day-ahead prices or critical peak signals, both of which are embodied in dynamic tariffs. While quite different in the degree of customer commitment, each response may yield market price and reliability benefits and more efficient energy usage decisions. This is the rationale for having a "portfolio," or mix, of demand response programs that will appeal to the greatest number of customers.

For example, in Phase 1 we are considering two demand bidding programs. Both are similar in allowing customers to shed load when market prices reach a set threshold. However one, the IOU DBP, is designed for customers not willing to make a firm commitment, who are paid solely for the energy reductions they actually choose to make. The other, the CPA DRP, has reservation payments scaled to firm commitments to shed load, measurement protocols to be sure that load reductions can be accurately measured, and penalties for failing to meet load reduction commitments. Some customers prefer the freedom of the former approach, while others prefer the security of a known payment stream provided by the latter. Under the design principles we

[20] WG 2 Report dated November 15, 2003, p. 4.

adopt, it is conceivable that both features could be combined in a single offering for large customers.

C. Mandatory or Voluntary Participation?

Given the nature of large customer electricity usage, as discussed above, WG2 recommends that the 2003 tariff offerings should be voluntary. This could not have been an easy call, for mandatory programs avoid several problems endemic to voluntary programs. For example, in a voluntary setting, certain customers may elect to participate in a demand response program that benefits their particular load profile without motivating them to shift or reduce demand in any way. Other customers may simply choose not to participate in a voluntary demand response program, thereby diminishing overall demand response capability. However there are strong arguments against mandatory tariffs for large customers. Some of these customers simply are not able to respond to price signals because of the nature of their production methods. To force them onto a tariff that essentially raises their rates as they fail to respond seems unfair. And to raise their rates without a hearing is highly questionable.[21] In view of these competing factors, the WG2 participants believe that there are too many complications to consider imposing a mandatory program on large customers in the near term.

Although TURN states that it lacked the resources to participate fully in WG2, it did file comments on the WG2 Reports, opposing the WG2 recommendation for a voluntary program for large customers. TURN cites the interruptible programs in place during 1992-2000, where customers who were confronted with the probability of interruptions after 2000 left the program in

[21] Working Group 2 Report dated November 15, 2002, p. 32.

large numbers. TURN argues that large customer behavior has not changed in the past two years, and there remains a significant drop off in subscription for industrial demand reduction programs, especially for Edison, notwithstanding the utility's payment of millions of dollars of incentives over many years.[22] TURN argues that this experience demonstrates that policy makers will never be able to attract large customers to demand side programs without guaranteeing these customers both an upside financial benefit and little or no downside risk. TURN believes the Commission must adopt a mandatory program for large customers, and proposes that all customer with demand greater than 200kW who have received free advanced meters from AB29X funds, be transferred to critical peak pricing on a mandatory basis.

TURN acknowledges that some of the details of this proposal, which was first detailed in its written comments and has not been vetted in WG2, remain somewhat general. Nonetheless it believes that the proposal, along with the Commission's June 1, 2001 rate increase, which allocated significant rate surcharges to the large customer class via surcharges for on-peak energy charges, will significantly improve the Commission's chances of achieving its demand reduction goals. It believes the Commission will find, upon investigation, that there is considerable evidence that the current rate design, which includes on-peak energy surcharges in the range of $0.20/kWh, is already providing large customers with meaningful price signals to reduce demand during these periods.[23]

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[22] TURN Comments on WG2 Reports, pp. 3 – 5.

[23] TURN Comments on WG2 Reports, pp. 12 – 13.

We are at a very early stage in looking at price responsive demand reduction programs for large customers. The experience TURN cites comes from mandatory load curtailment programs, not price responsive programs, and it is not entirely clear that large customer behavior in the one area can be extrapolated to the other. There simply is no record at this point in the proceeding to reject the WG2 consensus view and impose a mandatory CPP on large commercial customers in the near term. Further, it is unclear in the context of price-responsive programs that mandatory response is even needed, unlike emergency programs that are designed to ensure reliable system operations.

D. Program Details

In its November 15th report, WG3 presented six tariff and program proposals for our consideration, without recommending adoption of any specific one. Rather WG 2 recommended selection of a mix of the programs, consistent with the design objectives discussed earlier. Thereafter, on December 23, 2002, the respondent IOUs informed the ALJ that they wished to withdraw two of the earlier tariff proposals and substitute a new CPP proposal they felt would garner more customer acceptance. The ALJ permitted withdrawal of the two earlier IOU proposals and the submission of these new proposals in late December, and WG2 subsequently met to consider them, and then filed its third report on January 16, 2003. As a result, at the conclusion of Phase 1 we consider three dynamic pricing proposals: two are critical peak pricing tariffs (one presented by ACWA and the other known as the “Joint Utilities’ CPP Proposal” or the “Joint Proposal,” presented by the respondent IOUs), and the third is SDG&E’ variation on the Joint Proposal, including the HPO tariff. We also consider two demand bidding programs, one presented jointly by the respondent IOUs and the other presented by the CPA. And finally, we consider two pilot programs: a proposal presented by IMServ known as the "Constrained T&D Capacity Proposal"[24] and an real time pricing pilot presented by Infotility.[25]

1. Dynamic Pricing Proposals

In general terms, a dynamic rate allows rates to be adjusted on short notice, typically an hour or day ahead, as a function of system conditions. A dynamic rate cannot be fully predetermined at the time the tariff goes into effect; either the price or the timing is unknown until real-time system conditions warrant a price adjustment. Critical peak pricing tariffs and real time pricing tariffs contain dynamic rates.[26]

A critical peak pricing tariff includes a dynamic rate that allows a short-term price increase to a predetermined level (or levels) to reflect real time system conditions. In a *fixed-period* CPP, the time and duration of the price increase are predetermined, but the days are not predetermined. In a *variable-period* CPP, the time, duration, and day of the price increase are not predetermined.[27]

A real time pricing (RTP) rate is a dynamic rate that allows prices to be adjusted frequently, typically on an hourly basis, to reflect real-time system conditions.

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[24] See WG2 Report dated December 13, 2002, pp. 86 – 93.

[25] See WG2 Report dated December 13, 2002, pp. 93 – 94.

[26] See *Glossary of Retail Electricity Rate Terms*, Attachment A to D.03-03-036.

[27] See D.03-03-036, Attachment A, "*Glossary of Retail Electricity Rate Terms.*"

a. The ACWA CPP Proposal

The ACWA CPP proposal, initially presented in the November 15, 2003 WG2 Report[28] is designed to present little or no risk for customers; to be easily understood; and to be inexpensive (in terms of personnel or hardware) to implement. ACWA proposes that CPP be an option available to any IOU bundled service end-use customer who qualifies for existing rate schedules A-10, E-20, GS-2, and TOU-8. The IOU will determine the Critical Peak Periods (based upon low reserves, local transmission problems, high wholesale prices, or system peak), and will call at least 6 CPP hours each summer month. Under the ACWA proposal, the billing demand calculation under the existing rates is adjusted based upon the customer's average hourly demand during the Critical Peak hours of use in a summer month. After the first 6 Critical Peak hours, an approximately $1.00/kWh ($1.50 for customers with less than 500 kW peak demand) credit accrues during all Critical Peak hours for each kWh the customer reduces below the monthly average hourly kWh use during the Peak Period. Thus participants must perform during peak periods (minimum 6 hours per summer month) to achieve savings under the CPP tariff. For customers, this is a "no lose" proposition. Customers who do not respond pay no more than their current demand charges.

In its written comments, BOMA applauds the ACWA proposal as thoughtfully fleshed out, and supports it as the proposal that best protects customers. On the other hand, the respondent IOUs object to the ACWA plan because it provides significant potential bill savings to participating customers,

[28] See, WG2 Report dated November15, 2002, pp. 60-70.

on a no-risk basis, with no assurance of new demand reductions. This range of views highlights the chasm we must bridge.

Our goal is to develop programs that will provide meaningful demand response. Naturally these programs must be attractive to participating customers. But there is legitimate concern that ACWA's proposal provides generous bill savings to participants who provide little demand response in return, as customers need only respond during 6 critical peak hours each summer month in order to achieve a significant reduction in their demand charge. Further, if the customer's peak demand already occurs outside the 6 hours in question, the customer receives these savings in return for virtually no response. There must be a meaningful quid pro quo. Additionally, the ACWA CPP lengthens the averaging period used in determining the customer's demand charge (from a 15 minute interval to 6 hours), thus creating a revenue shortfall for all other customers. On balance these factors persuade us against adoption of the ACWA CPP proposal.

b. The Joint IOU CPP Proposals

The Joint Proposal is designed to appeal to commercial office buildings and other similarly situated customers with large air conditioning loads. This rate will be offered to large customers (>200 kW), all of whom are already equipped with appropriate interval meters due to AB29X. It will be offered during the summer peak season, as defined in each utility's currently applicable tariffs. Critical peaks will have two pricing levels, covering the seven-hour peak period. There will be a fixed number of CPP operating days (i.e., a maximum of

12 CPP days called per summer).[29] High priced CPP days will be communicated to customers on a day-ahead basis. CPP days will be selected on the basis of forecasted utility-specific weather conditions with a predetermined zone.[30]

As proposed, for usage between 3:00 and 6:00 p.m. on a CPP day, critical peak prices would be set at a level equivalent to five times the utility's specific otherwise-applicable total on-peak energy charge (that period most closely corresponding to the statewide system peak). For usage between Noon and 3:00 p.m. and between 6:00 p.m. and 7:00 p.m. on a CPP day, critical peak prices would be set at a level equivalent to three times the utility's specific otherwise-applicable total partial peak energy charge. Excess revenue amounts generated by CPP rates on program operating days will be used to discount on-peak and part-peak energy charges on non-CPP operating dates, such that rates are revenue neutral in comparison to each otherwise-applicable rate schedule on a class-average basis. Revenue neutral in this case will mean that if an average usage level customer is on this rate, and does not respond by reducing demand during the called critical peak periods, the customer will pay the same total bill, or same average rate, as if they had been on the default tariff.

As proposed, this program would not be available to those currently participating in an existing load reduction program. The customer group targeted for this rate accounts for approximately 6,500 MW of aggregate commercial air conditioning load on typical summer peak days. If the program

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[29] In their response to the ALJ's February 21, 2003 Ruling, the IOUs submitted pro forma tariffs including this 12-day provision.

[30] See, Southern California Edison Company's Addendum to Working Group 2 Report Submitting Critical Peak Pricing Proposal, Attachment "A," p. 1.

is implemented voluntarily, without transitional incentives, the IOUs project totals of 35 MW in 2003, 76 MW in 2004, and 85 MW in 2005. We discuss adoption of several transitional incentives later in this decision.

There are several critiques of the Joint Proposal. For example, on January 21, 2003, the City and County of San Francisco (CCSF) requested permission to intervene in this proceeding in order to raise issues regarding the Joint Proposal's interplay with San Francisco's unique peak electric loads. CCSF supports the Joint Proposal as consistent with CCSF's Electricity Resource Plan which seeks a 16 MW reduction in peak load by 2004. However, CCSF is concerned that the statewide Joint Proposal does not adequately capture San Francisco's peak load profile. CCSF wishes to work with PG&E to develop a pilot program to ensure that 1) the program will be applicable from May through October, consistent with PG&E's electric tariff definition of the summer season; 2) the number of operating days will be increased so that program can be deployed anytime during the weekdays; and 3) the selection criteria for CPP days will be modified so that they will be based on weather conditions specific to San Francisco's climate rather than on a predetermined zone.

We agree that the load, demand, and capacity characteristics of the San Francisco peninsula are unique in the PG&E service territory and merit special consideration.[31] CCSF's broader concerns about transmission constraints and local generation issues are beyond the scope of this proceeding, although the issues raised by CCSF have been acknowledged by the WG2 participants, where

[31] CCSF has demonstrated that it has a direct and substantial interest in the outcome of this proceeding that cannot be represented adequately by any other party. Pursuant to Rule 45, we will grant its motion to intervene.

discussions have focused on how the CPP proposals might be modified to address these concerns in some meaningful fashion.[32] Rather than create a CCSF pilot program, however, we will direct PG&E to work with CCSF to create a localized marketing and recruitment area and triggering conditions for the existing CPP tariff proposal. Our decision requires PG&E and CCSF to submit an advice letter containing the details of this localized plan.

BOMA, whose constituency is the targeted audience for the CPP offering, also regards the Joint Proposal as unattractive in key respects. BOMA is concerned that its members may not have the ability to shed the significant additional load that must be shed during the CPP periods, and that the IOUs have given insufficient attention to understanding and addressing these obstacles. BOMA also believes the Joint Proposal requires further fleshing out.[33] TURN opposes adoption of the Joint Proposal, arguing that it relieves large customers from their embedded generation cost responsibilities, provides meaningless incentives, has no mathematical foundation, and is better evaluated in a traditional rate design proceeding.[34] ORA also expresses some concerns about the projected participation levels and demand response from the Joint Proposal, as well as the connection between incentives and revenue neutrality.[35]

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[32] The CPA DRP proposal, discussed subsequently, also provides a potential solution for demand response in transmission constrained areas by allowing a targeted operation in such areas.

[33] BOMA's January 27, 2003 Comments on the Working Group 2 Reports, pp 7 – 8.

[34] TURN's January 27, 2003 Comments on the Working Group 2 Reports, pp. 7 – 9.

[35] ORA's January 27, 2003 Comments on the Working Group 2 Reports, p. 3.

DGS, on the other hand, supports the Joint Proposal as a way to shave expensive, peak energy consumption.[36]

We understand the initial reluctance of large customer representatives such as BOMA to embrace CPP. We also understand why others such as DGS and the CCSF embrace the program. No one program appeals to all large users. That is why we have considered a variety of tariffs and programs in Phase 1 and will be considering others, such as two-part RTP tariffs, in Phase 2. At this particular time, however, it is important to provide at least some options to large customers and to encourage their participation in these various programs so that we can begin to meet the state's demand response goals. The CPP effort involves a relatively modest expenditure through 2004, provides customer choice, and also allows us to take advantage of the AB29X infrastructure that is already in place in order to increase demand response in the near term. For all of these reasons, we authorize the Joint Proposal, subject to certain modifications discussed subsequently in the "Customer Participation Issues" section of this decision. These modifications, relating to agricultural customer participation, multiple meter situations, multiple program participation, and the use of incentives, are designed to promote customer participation in the program.

c. SDG&E's Suggested Variations on the Joint Proposal (CPP/HPO)

SDG&E intends to maintain its previously authorized critical peak tariff (Schedule AL-TOU-CPP) while implementing a new CPP tariff based on the Joint

[36] DGS January 27, 2003 Comments on the Working Group 2 Reports, pp 2- 3.

Proposal's statewide program.[37] However as a modification to the Joint Proposal, and in the interests of capturing additional demand reduction from commercial office building complexes or business industrial parks, SDG&E recommends that the customer participation threshold be reduced from 200 kW to 20 kW. If we were to accept this recommendation, the CPP rate would be available to SDG&E's AL-TOU/EECC rate schedule, which includes all commercial accounts 20kW or greater. SDG&E has over 16,000 such accounts and plans to target about 6,700 of these for CPP participation. SDG&E projects the additional metering costs at $43,750 for 2003 and at $20,000 per year thereafter.[38]

At this time, we will not adopt SDG&E's proposal to expand this program to customers whose usage spans 20 kW to 200 kW. There is no record for doing so, or for calculating the costs of such an expanded program. Instead we will confine the CPP program to SDG&E customers whose usage exceeds 100 kW, as this Commission has previously authorized SDG&E to procure, install and operate real time meters for each of its customers (except exempted agricultural customers) with peak demand of 100 kW or more (D. 01-05-032, *mimeo* p. 6).[39] [40]

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[37] Errata to Comments of SDG&E on Working Group 2 Reports, dated January 31, 2003, p. 3.

[38] SDG&E's Supplemental Comments Responding to Data Request in February 21, 2003 Ruling, p. 3.

[39] That decision allowed the establishment of an RTEM Memorandum Account associated with the $12.5 million of purchase and installation costs for the meters and the accompanying meter data management system, while deferring the issue of actual cost recovery and cost allocation to a subsequent reasonableness review.

[40] SDG&E's customers in the 200-300 kW range do not have AB29X meters installed, so SDG&E will incur additional costs if these customers participate in the programs

Footnote continued on next page

SDG&E also wishes to convert an existing pilot program, its Hourly Pricing Option (HPO), into a full-scale program to be provided in concert with the Joint Proposal. We approved SDG&E's existing HPO in Resolution E-3782 issued August 22, 2002, so that it could launch an hourly metering and pricing pilot program during the summer of 2002 to test customer acceptance, demand response, behind-the-meter energy management technologies, and billing processes associated with dynamic retail energy commodity pricing. This HPO for commercial customers was to use interval meters, and charge varying on-peak hourly rates to customers based on next-day demand forecasts. The utility was to provide participating customers with hourly commodity price information on a day-ahead basis through the Internet, allowing them to adjust their usage accordingly. As approved, the HPO was to be offered to no more than 35 commercial and industrial customers with demands of 20 kW or greater on a first-come, first-served basis. However, in anticipation of decisions to be issued in this docket, SDG&E has not been aggressively promoting the HPO tariff to customers and, as of January 31, 2003, it had not signed up any customers for this program.[41] Instead, SDG&E proposes to convert the HPO into a full-scale program and modify it by expanding the hourly prices to semi-peak periods, on the rationale that customers will have greater flexibility to reduce

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authorized in this decision. However this Commission has already authorized SDG&E to procure real time meters for customers with usage exceeding 100 kW (D.01-05-032).

[41] SDG&E's February 1, 2003 Program Evaluation Report #1, "Hourly Pricing Option Pilot, Schedule EECC-HPO," p. 6. As required by Resolution E-3782, SDG&E served this report on the service list of R.02-06-001.

costs by shifting or reducing load from the higher on-peak hourly periods to the semi-peak "shoulder" periods.[42]

The CPP tariff proposed jointly by the respondent IOUs would create a tariff with two high on-peak rates in critical situations, but leave prices in the shoulder and off-peak periods averaged as in normal TOU tariffs. Since the SDG&E proposal expands the number of hours for which hourly rates are revealed to the participant, and thus breaks new ground, we will adopt it, making the HPO a full-scale program for SDG&E and as part of that, extending its hourly pricing features to cover shoulder hours. Consistent with the customer participation levels authorized for the CPP tariff, we will permit SDG&E to offer the HPO tariff to all customers with monthly demands >100 kW. However for the time being, we will confine this outcome to SDG&E, and not impose it upon PG&E or Edison. There is a simple reason for this: while WG 2 is in the early stages of exploring the development of a two part tariff suitable for wider application, this process must involve all interested parties and the resulting work products must be thoroughly vetted in this proceeding. In preparation for the next phase of this proceeding, the assigned Commissioner or ALJ will issue a ruling providing guidance to the parties on how this process should unfold.

2. Demand Bidding Programs

In broad terms, demand bidding programs allow the customer to bid the amount of electric load they can reduce at a certain predetermined price. Such programs can be voluntary (giving the customer the choice about whether and how much to participate on any particular day in response to utility requests), or they can require the customer's firm commitment. In Phase 1, we consider each

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[42] SDG&E's January 27, 2003 Comments on the WG2 Reports, pp. 5 –6.

type of program: the IOU Demand Bidding Program, an example of a voluntary program, and the CPA Demand Reserves Program, which requires a firm commitment.

a. IOU Demand Bidding Program

This Commission requires that demand response programs be included in each utility's long-term resource plan[43], a decision made after this rulemaking was underway, and thus causing some retooling of the IOUs' Phase 1 demand bidding proposal. The IOUs presented their original joint proposal in the November 15, 2002 WG2 report, and subsequently modified it.[44]

The IOUs initially proposed that a common statewide market-based DBP program (requiring a price trigger) be developed after the ISO's day-ahead market has been established, as projected in Spring 2004.[45] However they now believe there is no reason to wait. The IOUs have always favored the continuation of the existing Commission-authorized reliability-based demand bidding program. However they now propose the expansion of available demand bidding options, allowing participants to reduce demand voluntarily when requested by the IOUs in one of two ways: via 1) a price trigger and 2) a system emergency trigger.

Under their current market-based DBP proposal, IOU procurement departments will use current information and historical trends to forecast an hourly "price offer" on a day-ahead basis. This is a form of utility-specific

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[43] D.02-01-062, mimeo, p. 28.

[44] See Third Report of WG2 dated January 16, 3002, p. 12; and Fourth Report of WG2 dated March 11, 2003, pp. 20-29.

[45] Third Report of WG2 dated January 16, 2003, p. 12.

procurement avoided cost. The "price offer" will be used as a cost effectiveness check in calling the program and valuing kW reductions. Events can be called any weekday (excluding defined holidays) between the hours of Noon and 8:00 PM and the program is triggered when the price offer is $0.15 per kWh or greater.

While a recurrence of year 2000 resource scenarios may be unlikely in the near term, the IOUs believe there is value in understanding the price responsiveness of customers during emergency situations. To that end, they propose that artificial conditions periodically be put in place to obtain this data, and for this purpose they would test the DBP at "emergency incentive" levels up to twice per year, four hours total. This emergency trigger, meant to simulate a CAISO "Alert" or "Warning" notification (when system reserves are forecast to be 7% or less between Noon and 8 PM weekdays only), would serve not only as an incentive to the customer to join the program, but would also determine the extent of participant response. A customer must submit a "committed load reduction" bid, and will receive $.50 per kWh of demand reduced during a test event. For purposes of payment, minimum (50%) and maximum (150%) load reduction criteria are applied.

In order to determine performance, the IOUs will use a new variant of a customer specific 10-day rolling average energy usage baseline. There was some concern that the current methodology does not scale baseline to actual demand, and BOMA argued that it may be unfair to customers with weather-sensitive loads. The IOUs responded by proposing a new method of calculating the 10-day rolling average, "using the average of energy usage for the three highest days for the same hour during the past ten similar days prior to a DBP event."[46] They assert that this new method tends to reduce any negative bias that a simple 10-day rolling average produces for temperature-sensitive customer loads, should result in baselines that better reflect the load that would have been used absent the program, and avoids the gaming opportunities provided by adjustment mechanisms that scale baselines based on usage just prior to a DBP event.[47] On balance, the revision to the baseline methodology proposed in the March 11 WG2 Report appears to address concerns about the fairness of the rolling 10 day baseline calculation, and we will make no further modification to the baseline calculation in this decision.

The IOUs propose to make their demand bidding program available to individual commercial/industrial bundled service customers not otherwise on an RTP base rate, or Agricultural rate schedules, whose usage is 200 kW or above, and who have interval meters capable of recording metered data on a 15 minute interval. The IOUs propose to offer such interval meters to the customers at the utility's expense if such metering is not already available on site. Customers must take service under the provisions of their otherwise applicable rate schedule. Participating customers must commit to reduce load by at least 100 kW during a DBP event and agree to reduce their load by their committed load reduction amount in the event of an emergency DBP event. Under the proposal, there would be no aggregation of customer accounts or their associated loads.

Besides these operational modifications to the existing demand response program, the IOUs propose to offer a transitional technical incentive

[46] WG2 Report dated March 11, 2003, p.25.

[47] SDG&E Comments in response to February 21, 2003 ALJ Ruling, p. 5.

package to DBP participants. This incentive package is the same as that offered to CPP participants, as discussed subsequently in this decision.

We agree that there is no reason to wait for the CAISO to develop a day-ahead market in order to implement the DBP, as the IOUs' most recent DBP proposal implicitly acknowledges, and we will adopt the Joint Utility Demand Bidding Program, as presented in the March 11, 2003 WG2 Report[48], subject to certain modifications. First, we do not accept the limitation proffered by the IOUs that the DBP be available only to those not on another dynamic pricing tariff. In addressing multiple participation issues subsequently in this decision, we specify certain circumstances under which customers may participate in both the CPP and the IOU DBP. Second, we will allow some participation of multiple meters at a single site, under guidelines detailed subsequently in this decision. Third, we see no reason to exclude from the DBP certain agricultural customers whose usage exceeds 200 kW and who have interval meters in place. Since agricultural customers are currently participating in the IOUs' reliability-based demand response programs,[49] there can be no argument that their participation is infeasible, or that their participation, as limited above, increases costs to other ratepayers. To our knowledge no specific argument against their participation in the proposed statewide program has been made. Therefore, this order allows certain agricultural customers to participate in the adopted Joint Utility Demand Bidding Program.

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[48] Exclusive of the incentive features whose merits are addressed subsequently.

[49] SCE's Agriculture and Pumping Interruptible Program and TOU-PA-SOP-I tariff.

b. The CPA Demand Reserves Program

In the interests of coordinating an existing program with the IOU proposals being developed in this proceeding, WG2 also assessed how the CPA's existing Demand Reserves Partnership (DRP) could be used to meet our demand response goals. The design of the CPA DRP is governed by a contract between CPA and the Department of Water Resources (DWR). In D.02-10-062 we directed the IOUs to include the available resources from the CPA DRP in their long-term procurement plans. In D.03-02-031 we approved $29 million in CPA DRP costs for inclusion in the 2003 DWR revenue requirement. In this decision, we determine how this program will assist in meeting our stated demand response goals. In that regard, one of its primary benefits is its availability to a much broader array of participants than the IOUs' DBP; any end user (bundled or direct access) of the IOUs, as well as end users of cooperating load serving entities in California may participate in the CPA DRP.

Under this program the CPA uses load reduction by end users to provide demand reserves in the wholesale market. These demand reserves can be used in two ways: 1) Ancillary Services –as ten minute response non-spinning reserves or sixty minute response replacement reserves in the ISO markets; and 2) Call Option – as energy supplied in the ISO day ahead, hour ahead or supplementary energy markets during high wholesale market price or critical demand times. CPA contracts with demand reserve providers to work with end users and be contractually responsible for delivering the load reduction when called. Demand reduction for individual end users is limited to 11 AM to 7 PM, Monday to Friday for 24 hours per month, or 150 hours per year. Two different types of baselines are used to compute load reduction, one for those participating in the Ancillary Services of Supplemental Energy Markets, and the other for Call Options delivered into the ISO day ahead or hour ahead markets.[50]

At present, each IOU will receive credit towards the demand response goals set in this proceeding for any CPA DRP resources that it schedules. And in the absence of further direction from the Commission, it is likely that each IOU will schedule with the CAISO those CPA DRP resources that are inside or closest to its retail service area. However we will direct the IOUs to work with the CPA and DWR to develop and file, within 120 days, a mutually acceptable alternative mechanism for allocating these resources in 2004, unless such an alternative mechanism is developed in the procurement proceeding (R. 01-10-024). This timetable is designed to allow resolution of the issue by the Commission prior to the start of 2004.

While D. 02-10-062 requires the inclusion of DRP resources in the IOUs' long-term procurement plans, it is evident that the IOUs need to coordinate their scheduling activities with the CPA more closely in order to ensure that the DRP resources are actually dispatched when it is cost effective to do so. The IOUs must coordinate their customer, meter, scheduling and settlement activities in a manner that maximizes the full potential of the CPA DRP. To that end, we will require the IOUs to submit a DRP Implementation Plan, in coordination with the CPA, detailing how they will use the DRP resource effectively.

c. Parallel Demand Bidding Programs

We are aware that the CPA DRP and the statewide IOU DBP program share many similarities and thus may compete for customers. This

[50] See Working Group 2 Report dated January 16, 2003, pp. 18 – 22.

reality must be balanced against the fact that there are key differences in these programs as well. For example, the "call option" portion of the DRP and the IOUs' DBP offer alternative means for customers willing to curtail load on a day-ahead or day-of scheduled basis. And the DRP Call option provides a much greater payment to the program participant than does the DBP, but it also obligates the participant to make a specified load reduction. Thus there is greater certainty about the load reductions of those participating in the DRP. Considering all of these factors, and consistent with our plan to offer a variety of options to large customers, we believe both demand bidding programs, operating in parallel, should be available. This means that in the near term the IOUs will be able to dispatch from either one.

3. Pilot Programs

a. The T&D Peak Capacity Proposal

The T&D Peak capacity proposal is presented by IMServ, whose products and services include collecting and providing advanced energy information, including settlement services to utilities and energy service providers, among others, and providing metering services. The proposal is rooted in the concept that customers should receive financial benefits in the form of reduced transmission and distribution (T&D) charges when they take actions that provide benefits on constrained T&D systems, thereby ameliorating adverse impacts associated with T&D upgrades and the environmental impacts of running peaking units in transmission constrained areas. This proposal targets electric customers (both direct access and bundled) above and below 200 kW in T&D constrained areas.

IMServ proposes that this program be implemented via the CPA's Transmission Pilot Program. The utilities would be required to identify constrained T&D areas as well as cost effective incentives for reducing these constraints. Finally the program must be marketed and customer T&D reductions calculated. Proof of concept operation of the pilot would occur during summer 2003, and the program would be expanded during summer 2004.

In D. 03-03-036, we considered and rejected this program for small commercial customers because it lacked the specificity necessary for implementation in Phase 1. The result is no different here. The pilot description is simply too general and the specific concepts to be piloted are missing. By summer 2003 it is simply impossible to develop hourly prices for transmission and distribution constraint costs and to use such prices as inputs to a demand response program. Therefore we will not approve the IMServ proposal in this decision.

b. The Infotility Proposal

During the WG2 process, Infotility presented a draft real time pricing proposal which stimulated discussion, and caused the WG2 participants to recommend that testing alternative design features of a two part RTP tariff might prove useful.[51] The Infotility proposal is designed to test or identify 1) customer interest and response to a real time price signal across multiple building types; 2) customer preferences for baseline methodologies; 3) specific customer education requirements prior to participation in a two-part RTP tariff; 4) technical and administrative barriers to a full roll out; 5) customer satisfaction; and 6) "lessons learned."

[51] WG2 Report dated December 13, 2002, pp. 93-94. See also Appendix C to the December 13th report.

Under the pilot proposal, participants remain on their existing tariff schedules and are billed for actual usage. They are debited/credited at a second rate (the market price) for the difference between actual usage and their baseline usage. Baselines are negotiated and may be adjusted monthly or on a day ahead basis. At the end of each month, customers receive a statement summarizing their performance relative to the baseline method employed under the program. If there is a net positive balance, customers earn an incentive credit; if there is a net negative balance, the customer is charged a debit. At the end of the program the customer is eligible to receive an incentive payment equal to the positive balance at the end of the program. If there is a negative balance the participating customer receives nothing.

Expected participants would be recruited from those organizations whose members have expressed interest in a two-part RTP tariff in the past. These include the Silicon Valley Manufacturing Group, OBMC program participants excluded from demand response programs, CMTA, BOMA, and other business and trade organizations. The program would be available to all large bundled customers with at least 200kW of maximum demand. Nearly all of these customers have already received the interval meters that are needed to participate.

Time did not permit the full exploration of the Infotility, or similar RTP proposals during Phase 1. However given the keen interest in this issue by many participants, we will authorize the WG2 participants to develop a pilot or pilots or consider alternatives that test two-part RTP tariff design features, and they may use the Infotility proposal as a starting point.[52] We will cap the cost of this pilot(s) at $2.8 million, as detailed in the December 13, 2002 WG2 report.[53]

E. Customer Participation Issues

Having decided to make four of the tariffs / programs presented by WG2 (the Joint IOU CPP, the SDG&E HPO, the IOU DBP, and the CPA DRP) available to large customers, we now consider certain steps designed to encourage participation in them.

1. Agricultural Customers

Initially we address respondents' proposal to exclude agricultural customers from participation in the various tariff proposals that have been submitted in Phase 1. ACWA opposes this exclusion, arguing that the Commission should order the IOUs to install interval meters (and meter data communication) on all 200 kW and above meters and allow the cost of these installations as authorized additions to plant for ratemaking purposes.

On February 21, 2003, the ALJ issued a ruling requesting information from the IOUs about the estimated costs of installing AB29X advanced metering systems that would enable agricultural customers to participate in demand response tariffs or programs. Edison reported that agricultural customers were included in its AB29X RTEM program and that no additional funding is necessary other than that requested in its current GRC filing.[54] SDG&E reported that its AB29X implementation plan includes

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[52] The original schedule proposed by WG2 has slipped and it will be necessary for them to meet to develop a new schedule to test two-part RTP tariff design features.

[53] See Appendix C of the December 13, 2002 WG2 report.

[54] Edison Response to ALJ's February 21, 2003 Ruling, p. 4.

installation of such meters for its agricultural customers with demands >300 kW;[55] for its 461 agricultural customers with demands <200 kW, SDG&E estimates that no more than 10 sites per year would participate in the CPP, and that estimated annual metering costs would not exceed $20,000 for these customers;[56] for its 36 agricultural customers with demands between 200 kW and 300 kW, SDG&E estimates initial costs of $63,000, and ongoing annual costs of $10,000.[57] PG&E reports that it currently has 908 agricultural customers with demands >200 kW. Of these, 251 already have real time meters, and 657 have kWh or time of use meters. PG&E provides a range of one-time meter installation costs ($854,000 to $1.6 million, depending upon telecommunications options) for these 657 customers.[58]

Based on the IOUs' responses to the ALJ's February 21st ruling, it appears that the major cost issue relative to agricultural customer participation, is posed by PG&E's 657 customers who lack interval meters. Based on the figures presented, the cost implications for Edison and SDG&E appear to be less significant than the PG&E situation. While we wish to maximize the participation of all customers, including agricultural customers, in the demand response programs authorized in this decision, the record is not well developed on the issued of agricultural customer participation. We must carefully consider the participation of agricultural customers to determine which rate schedules are

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[55] SDG&E Response to ALJ's February 21, 2003 Ruling, p.2

[56] SDG&E Supplemental Response to ALJ's February 21, 2003 Ruling, p. 2.

[57] SDG&E Response to ALJ's February 21, 2003 Ruling, p. 2.

[58] PG&E Response to ALJ's February 21, 2003 Ruling, pp. 5 –6.

likely to provide meaningful, cost-effective demand response within the structure of the programs adopted in this decision. This we will do in Phase 2 of this proceeding. In order to allow some agricultural participation now, at the 200 kW level and above, we will authorize participation by agricultural customers on certain specific rate schedules, as proposed by PG&E and SDG&E. For PG&E, these are customers on options C and F of the AG-4 and AG-5 rate schedules, who have an existing interval meter. For SDG&E, eligible customers must be on schedule PA-T-1. Edison has not proposed specific tariff schedules, but rather proposes to transfer participating agricultural customers to discrete commercial accounts. We do not adopt this proposal, but instead will require Edison to identify specific tariff schedules eligible for participation. The 200 kW threshold, rather than the 100 kW threshold approved in D.01-05-032, applies to SDG&E as well, since the authorization provided in that decision excluded agricultural customers. So that additional agricultural customers who do not currently have interval meters are able to participate in these programs in the future, we will review the cost implications of such participation in Phase 2 of this proceeding.

2. Multiple Meter Situations

WG2 explored, but did not resolve, the issue of participation by customers at multiple meter facilities, where no single meter is >200 kW, but in aggregate the total usage at the customer's facility exceeds 200 kW. The IOUs apparently implemented their RTP metering contracts with the CEC differently, so some of these customers may have interval meters while others do not. While we understand that a liberal aggregation policy will encourage more customer participation, that goal must be balanced against the unknown metering costs and the paucity of our present knowledge about small commercial customer demand response. Thus, we do not allow aggregation at this point, but we are open to exploring this issue further in Phase 2 of this proceeding.

We will, however, allow customers with multiple meters at one site where at least one meter already exceeds 200 kW, to combine other smaller meter loads at the same facility for purposes of participation in the tariffs or programs authorized in this decision. In the interests of clarity, we will adopt a proposal made by PG&E in its comments to define permissible multi-meter participation.

An eligible site must be defined under the IOU's appropriate tariff rules (e.g., Rule 1 for PG&E) or consist of adjacent customer premises.

3. Multiple Program Participation

The participation of customers in multiple programs presents challenging issues. From the customer perspective, participating in a specific program requires hardware investments and management attention that can be more readily justified if more than one program provides benefits. From the program operator perspective, there are technical complications, such as attribution of load reductions between two programs, or the possibility that the response from one program will affect the "baseline" of another program. From the system operator perspective, it may be difficult to credit loads participating in multiple programs unless it is very clear how this affects aggregate capacity and the incremental capacity remaining once the system conditions leading to a sequential call of programs has been initiated.

From our experience with traditional interruptible tariffs and load curtailment programs, the specific concerns have focused on two key concerns: the possibility that customers will be compensated multiple times for the same load response (so-called "double dipping"), and the possibility that potential load relief associated with a particular program will be "double counted."

Double counting occurs when the participating load on one program is the same load that is expected to perform in another program at the same time. Concerns have also been raised that multiple participation can add layers of billing and administrative costs associated with "overseeing" participation and calculating complex settlements. And utilities are concerned that such overlapping program participation may inhibit enrollment and cause customer dissatisfaction and confusion.[59]

On balance, however, we believe that multiple participation should be allowed provided that there are acceptable guidelines governing its applicability to the programs adopted in this decision. At this point in time, we will test multiple participation scenarios against the goal of avoiding both double dipping and double counting, as defined above. To develop this issue further in our rulemaking proceeding, the ALJ requested parties' comments on four multiple participation scenarios, some of which we will adopt. As we gain more experience with the interaction of these programs over time, we will be open to considering the adoption of additional scenarios.

a. CPP and CPA DRP (or IOU DBP)

May a bundled service customer on CPP also participate in the CPA DRP (or the IOUs' DBP) during hours when CPP prices are in effect, as long as the customer does not receive energy payments (from the CPA or the IOUs)? The answer is "yes," subject to certain conditions. This approach will balance providing an incentive to encourage customer participation and not making two energy payments for the same load reduction.

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[59] See, e.g., Edison comments to February 21, 2003 ALJ Ruling, p. 6; and SDG&E Comments to February 21, 2003 ALJ Ruling, p. 4.

While the IOUs oppose this scenario as unlikely to provide additional load reduction because DRP and CPP operating days must be the same (PG&E Comments to ALJ's February 21st Ruling, p. 7), we note that the CPP will be in effect for only 15 days per summer, whereas the DRP can be in effect 150 hours a year. Thus, CPP customers should be allowed to participate in the IOU DBP and CPA DRP, but not receive energy payments during CPP-event hours. The CPA offered to account for and monitor the multiple program ramifications of the CPA DRP in the January 16 WG2 report and we will request that they do so.[60]

b. OBMC/CPA DRP

May a customer on an OBMC rate also participate in the CPA DRP, as long as the customer does not receive energy payments from the CPA during hours when the OBMC curtailment is in effect? Here, the answer is "Yes."

PG&E asserts that this form of multiple participation makes it almost impossible to predict the expected load reduction when an OBMC event is called and thus can have serious ramifications in forecasting load drops during a rotating outage. While this may be true, the load reductions offered by the CPA DRP are considerably cheaper per MW than those load drops available during an emergency through OBMC. In addition, load participation in the DRP may help avoid the need to call an OBMC event. On its face, this proposed multiple participation also does not raise a double dipping or a double counting concern, because of the non-payment periods for the DRP program during an OBMC

[60] WG2 Report dated March 11, 2003, p. 26: "CPA will insure that no [energy] payment was made during hours that the utility program curtailment events were being exercised."

event. Thus, we will allow customers to participate in both the OBMC tariff and the CPA DRP.

c.A customer on interruptible rates who places additional load, below its firm service level, on the CPA DRP and receives reservation payments.

The IOUs recommend against this combination, but we will allow it. PG&E argues that most interruptible rate program participants have already specified relatively minimal firm service levels, so that additional load that might be made available for the CPA DRP under this approach would not be significant.[61] As events unfold, that may be the case, but it is not entirely clear now. What is clear is that if an interruptible rate program participant wanted to participate in the CPA DRP, the customer will receive a reservation payment for additional load below the firm service level designated by participation in interruptible tariffs. Theoretically, while both load segments would receive capacity payments, each segment represents "new" load and each would receive separate payments. There is no dual compensation. Therefore we will allow this combination.

d. May a customer on existing interruptible rates have existing curtailable load participate in the CPA DRP spot market options, assuming that no payments are made during the hours of curtailment due to the interruptible rate?

The answer is "yes," in part. Interruptible rate customers should be able to participate in the CPA's Supplemental Energy Markets, since no capacity

[61] PG&E Rersponse to ALJ's February 21, 2003 Ruling, p. 8.

payment if offered and no energy payments are made during interruptible program load curtailment events, as this scenario is described. Thus double compensation cannot occur under this scenario. Where interruptible customers already receive a capacity payment for participating load, they should not be allowed to participate in the Ancillary Service option (where a capacity payment is offered), as this would constitute double compensation.

4. Transitional Incentives

In its final report issued March 11, 2003, WG2 asserts that additional incentives are required to clear some significant hurdles that may impede our demand response goals. These hurdles include significant customer inexperience with demand response programs, customer reluctance to make the expenditure of time and effort necessary to participate in these programs effectively, as well as the perceived risk of participation. Representatives of one targeted group, BOMA, doubt that their constituencies will participate in the programs, as described in previous WG2 reports. And the IOUs report low levels of participation in existing demand bid programs, thus indicating that program changes, incentives, and more robust marketing may be needed to ensure broader participation. As a result WG2 proposes two basic transitional incentive options both of which would apply to the CPP Joint Proposal and SDG&E's HPO tariff, and one of which would apply to the IOUs' Demand Bidding Program.

These transitional incentives share common objectives: to increase initial customer participation levels, achieve significant demand response, provide the foundation for demand response programs, allow for experimentation with demand response capabilities, and accelerate the installation and use of demand response capabilities (March 11, 2003 WG2 Report, pp. 9 – 10).

a. CPP/HPO Incentive Proposal

For customers participating in the CPP and HPO programs, WG2 proposes that two types of transitional incentives be available, and that participants be allowed to receive one or both, either simultaneously or sequentially.

Under the proposed "rate protection incentive," the goal is to provide 100% bill protection, meaning that the participating customer pays no more than they would had they remained on their original rate schedule. Such customers are so protected for the first 12 months they are on the program, but no later than December 31, 2005. After the initial 12 months, if the sum of the CPP or HPO bills is higher than the sum of the bills on the otherwise applicable rate schedule, participants will receive the differential as a bill credit. There is no bill protection for individual customers after their initial 12 months on the program, or after December 31, 2005. BOMA maintains that the 100% bill protection feature should extend for the life of the CPP and HPO programs, and not just for 12 months, so as to allow customers to take the time necessary to adjust and adapt to the HPO/CPP regime.

Participation is capped at 500 MW (200 MW for PG&E; 200 MW for Edison; and 100 MW for SDG&E). The rate protection option is nearly no cost as long as existing revenue requirements are established and shortfalls are collected through appropriate balancing mechanisms.

To receive the benefit of the CPP, customers under the bill protection option must actually reduce peak demand by a minimum of 3% per CPP event averaged over the course of their 12 months' participation. If this minimal load shifting does not occur, the customer will not be given a CPP credit for participation under the program. Instead, the customer will only receive a refund to the extent its CPP bill exceeded the charges under its otherwise applicable tariff. The customer must also agree to allow the CEC or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the program. Finally, since the CPP is a voluntary tariff, a customer may leave at the end of the 12-month period during which they received 100% bill protection, but a customer who leaves before the 12-month commitment ends will not receive bill protection.

In the case of the HPO tariff, the WG2 reports are silent as to how the 3% performance requirement is to be met. HPO customers receive their pricing signals daily; therefore they cannot be expected to meet a 3% demand reduction requirement daily and we do not believe this is what is contemplated by WG2. Rather, a 3% reduction could be averaged over the entire time period of the customer's participation in the HPO (or annually, as applicable). In its tariff filing, SDG&E should specify the exact nature of the performance requirement for HPO customers.

BOMA is indifferent to the 3% performance obligation, but it does believe that a customer should receive the full bill protection if it remains on the CPP tariff through one of its four month summer cycles, as opposed to the full 12 month period. Edison is concerned about the complexities of implementing the 3% performance obligation and believes that offering bill protection for 12 months without the complex measurement obligation would encourage maximum participation in the most cost effective way.

Under the proposed technology incentive, a CPP or HPO participant may earn a rebate incentive for installing and using pre-approved technology that enhances the customer's ability to respond to curtailment events. Technology such as, but not limited to, automated load control hardware, energy management systems, and smart thermostats may be eligible for this transitional incentive. Professional technical advice solicited and received by the customer that leads to actual demand response may also be eligible for a rebate. One WG2 participant, Echelon, is concerned that the definition of "qualifying equipment" is unclear, as is the approval process for such equipment. Echelon also expresses the more specific concern that any equipment installed as part of the load reduction program should offer real time energy information to both the customer and the CEC.[62]

The transitional incentive will rebate up to $150 per kW of curtailable on-peak load for the combination of costs associated with receiving technical advice and installing qualified equipment. Incentives must lead to actual demand response, either by installing technology or through technical assistance that identifies modifying existing equipment or behavior.

Under the proposal, payments will not be made for technical assistance that does not lead to demand response. Upon completion of hardware installation and certification of potential on-peak load reductions, the customer will receive a transitional incentive equal to 50% of the potential payment. The remainder of the incentive will be paid after the customer has achieved certain milestones. More specifically, to receive the 50% rebate remainder, the customer must show a calculated peak demand reduction equal to at least 50% of their estimated load drop per CPP event, as averaged over 4 consecutive CPP or HPO months, while on the program and before December 31, 2005. If this minimum level of measured load shifting does not occur, the customer would not be given the 50% rebate remainder. BOMA is concerned that imposing a performance requirement as a condition for reimbursement will cause many customers to

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[62] See WG2 Report dated March 11, 2003, p. 20.

forego these programs, and suggests that some level of technical assistance be offered to customers free of charge.

To determine performance, kW drop is estimated as the difference between the customer's specific baseline for that hour (calculated via a 10 day rolling baseline) and the customers actual energy usage during that hour. Edison is concerned that the 10-day rolling baseline is a measurement not used in any form in the tariff, and thus would complicate billing operations. It proposes a compliance measure it considers much simpler: reduction in historical on-peak usage measured annually. BOMA is concerned about the manner in which the estimated load drops are set. It believes that individual customer input is necessary and it is concerned that weather and temperature conditions must be taken into account in a manner that does not disadvantage participating customers.

Funding for the CPP/HPO technical incentive option is proposed at $11.375 million for all three IOUs (the incentive costs totaling $10 million, program tracking costs totaling $750,000, and monitoring and evaluation costs totaling $625,000). Under the proposal, incentives would be available to participants until December 31, 2005, or until funding under the specified caps is exhausted. Proponents suggest that if one category of funding is exhausted, any remaining dollars from any category can be used to keep the entire program going.[63]

b. Demand Bidding Program Incentive Proposal

The IOUs propose to offer a transitional technical incentive package to DBP participants, identical to the transitional technical incentive package

[63] Working Group 2 Report dated March 11, 2003, p. 16.

offered to CPP / HPO participants. They will offer no bill protection incentive to these customers.

Funding for this DBP technical incentive option is proposed at $8.249 million for all three IOUs (the incentive costs totaling $5.375 million, emergency tests totaling $2.124 million, and program tracking costs totaling $750,000).[64]

CLECA questions whether there is sufficient evidence that technical incentives will motivate customers to participate in the DBP program, as DBP involves determining the load to be bid into the market and the price, in contrast to simply reducing load in response to a price signal.

For its part, CUE questions the cost of the technology incentives (for CPP and HPO, not just DBP), arguing that the Commission should not authorize such costs for ill-defined qualifying equipment until it has determined whether the free advanced meters already installed by the State will be an adequate "incentive" to meet demand response goals. CUE is concerned that WG2 exceeds its mission of developing tariffs that enable large customers to expand their demand response capabilities.

While supporting the objectives of the transitional incentives for all three programs, ORA believes that better and more effective incentives may be provided through the redesign of current TOU rates and changing the CPP rate design to increase the discount level so it would be equivalent to the interruptible and other demand response programs.

[64] Working Group 2 Report dated March 11, 2003, p. 24.

c. Adopted Transitional Incentives

For the CPP and HPO programs we will approve the bill protection incentive. Despite BOMA's argument that the program should extend well beyond 12 months for participating customers, we will authorize only a limited extension of the program, to 14 months. We do this because the CPP tariff may not be available until later this summer, and we are concerned that CPP events will be called in the Fall of 2004. This modest extension will provide meaningful protection during these additional events. We will also adopt the proposed 3% performance obligation, although we understand Edison's argument that a less rigorous performance obligation would be somewhat easier to implement. On balance, however, we prefer to have a more precise demand reduction measurement. To receive the benefit of the CPP, the customer under the bill protection option must actually reduce peak demand by a minimum of 3% over the course of their 14 months' participation. Bill protection will be credited at the end of the 14-month period of successful participation. If this minimal load shifting does not occur, the customer will not be given a CPP credit for participation under the bill protection program. Instead, the customer will only receive a refund to the extent its bill exceeded the charges under its otherwise applicable tariff.

We will also adopt two other proposed performance obligations: the site visit and survey completion agreement, and the 12 month commitment as a condition for receipt of bill protection. We will also cap the bill protection program at 500 MW as proposed, while noting that this incentive does not increase costs.

We decline to approve the technical equipment portion of the technology incentive for either the CPP/HPO or DBP. While an equipment-based rebate is potentially helpful in augmenting demand response based on the projections included in the March 11th WG 3 Report (Table 2), the proposal lacks key detail, including a method for determining what constitutes "qualifying technology." More significantly, the level of projected costs exceeds $11 million, a significant amount, with no indication of how much demand response such expenditure may encourage, a fact not counterbalanced by the inclusion of a performance requirement that would withhold 50% of the incentive in cases of nonperformance. Considering all of these factors, we will not approve the technology equipment component of the proposed technology incentive for any of the three programs in question.

We will, however, approve the technical assistance portion of the proposed incentive package, allowing a rebate for professional technical advice regarding installation of new equipment or modification of existing equipment or behavior because the modest expenditure we authorize[65] in that regard may indeed spur customer participation at a more acceptable cost. As originally proposed, a rebate of up to $150 per kW of curtailable on-peak load would be allowed for the combination of costs associated with receiving technical advice and installing technical equipment. Since we are not approving the technical equipment installation component, we will exercise our discretion and reduce the rebate accordingly. The authorized rebate amount for technical assistance will be $50 per kW of curtailable on-peak load for the costs associated with receiving technical assistance (related to the installation of new equipment or the modification of existing equipment or behavior) that leads to actual demand response. As with the original proposal, the customer will receive a transitional

[65] As shown in the Attachment A, the total amount of these incentives for 2003 and 2004 is $3.41 million, versus the $11.3 million proposed by WG2.

incentive equal to 50% of the potential payment upon certification of potential on-peak load reductions. The remainder of the incentive (the 50% remainder) will be paid after the customer has shown a calculated peak demand reduction equal to at least 50% of their estimated load drop per CPP event, as averaged over 4 consecutive CPP or HPO months, while on the program and before December 31, 2005. If this minimum level of measured load shifting does not occur, the customer will not receive the 50% remainder payment. To determine performance, the kW drop will be determined using the customer baseline proposed in the March 11th WG2 report.[66]

Our decision allows CPP/HPO customers to opt to receive just the bill protection incentive or both the bill protection incentive and the professional technical assistance incentive. Participants in the IOU DBP tariff may receive only the professional technical assistance incentive. Like our conditions stemming from receipt of incentives for CPP, any DBP customers accepting incentives must allow access to their site for research purposes by the CEC and/or its contracting agent. Since our decision allows some multiple program participation, we take this opportunity to clarify that multiple program participation does not entitle a customer to any additional incentive due to multiple participation.

Finally we note that the approved incentives are available to participants until December 31, 2005, or until funding under specified caps is exhausted. However if one category of funding is exhausted, any remaining

[66] Edison argued against this baseline due to concerns about billing complications, but this is the same baseline used in connection with the IOU DBP program approved in this decision.

dollars from any other category can be used to keep the entire incentive program running, with the caveat that at least 50% of the funding for technical assistance shall be guaranteed for the CPP.

F. Expected Impacts

We have taken several steps in this decision to augment customer participation in order to increase the amount of demand response generated by the adopted tariffs and programs. These include opening the tariffs and programs to agricultural customers, allowing certain multiple meter situations, allowing multiple program participations, as defined, and approving bill protection and professional technology assistance incentives on a transitional basis. As a result, it is expected that in calendar years 2003 and 2004, these demand response programs will provide approximately 411 MW and 954 MW, respectively (see Appendix B). While our decision to reject the technology portion of the transitional incentive proposal may diminish, to some degree, the expected MW contribution provided in Appendix B related to the statewide CPP, the HPO, and the IOUs' DBP, other steps taken to open these programs to agricultural customers and to authorize certain multiple-meter situations, and to allow discrete multiple program participation may offset any MW reduction.

G. Program Duration

The recent history of demand response programs in California is one of constant flux in program design. The WG2 participants strongly recommend that we embrace the concept of program stability, which is characterized as a policy allowing for consistent program design, eligibility and triggering mechanisms over multiple years. We are in total agreement with the WG2 participants on this point, and this rulemaking has exemplified this principle, embracing consistent and well-developed demand response policymaking over ad hoc program development. In our view, program stability will help us to achieve significant participation in demand response programs. To that end, the programs authorized in this decision are designed to continue beyond calendar year 2004, and have no expiration date, although funding is authorized in this decision through calendar year 2004. We will direct the IOUs to file evaluations for all authorized programs in this decision, as well as those authorized in D.02-04-060 in our interruptibles rulemaking, in the Fall of 2004 for the purpose of making any necessary revisions for summer 2005. At that time, we will consider authorizing additional funding as necessary. If any program modifications are necessary, they should not be disruptive to customers who have participated up to that point. And if a specific tariff or program needs to be terminated, those participating in it should be offered a reasonably smooth transition to another program if at all possible.

H. Elimination of Superfluous Programs and Tariffs

Over the years various efforts to introduce demand response pilots have resulted in some programs that are no longer active. For example, PG&E reports that there are no remaining customers enrolled under its experimental real time pricing tariff, Schedule A-RTP, and it views the Joint Proposal submitted in Phase 1 as a reasonable successor to that tariff. Therefore in the interests of avoiding customer confusion about available advanced tariff options, we will eliminate this outdated tariff.

In D.02-04-060 we authorized a pilot known as P-BIP in response to a CEC request to introduce a measure of market based pricing. The tariff has only one participant, and the WG2 participants see little harm in eliminating the pilot. The single participant will be encouraged and assisted to fit into another program.

I. Program Costs and Related Cost Issues

The cost figures for calendar years 2003 and 2004 for the programs approved in this decision, and discussed below, appear in Attachment "A" to this decision.

1. Cost-Effectiveness

We now address the question whether the four programs adopted in this decision are cost effective. California regulatory agencies have a long history of attempting to ensure that demand-side management (DSM) activities are cost effective. This Commission, in conjunction with the CEC, has established and periodically updated the Standard Practice Manual to create greater uniformity in assessments.[67] We have typically required that DSM programs be shown to be cost-effective according to one or more of the standardized tests.

The WG2 reports document the difficulties that participants have had in developing the inputs for and applying the current SPM tests to tariffs and programs that are designed to interact with markets.[68] The ALJ Ruling dated October 2, 2002 recognized some of the concerns of WG2 participants. In directing parties to proceed nonetheless, the ALJ Ruling dated November 13, 2002 provided high and low values for avoided cost scenarios to be used in the analysis.

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[67] CPUC, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects," October 2001.

[68] See "Issues for Cost-Effectiveness Analyses" on page 53 of the January 16, 2003 Working Group 2 report.

The Working Group 1 principals have expressed a belief that a long-term, sustainable direction was desirable for Demand Response options in this Proceeding. We concur that a focus on the cost of a new peaker power plant[69] is the most relevant standard in determining cost-effectiveness for tariffs and programs designed to be part of a growing reliance upon demand response, just as it has been for rate design and demand side management measure evaluation historically.

The Benefit-Cost ratios of the four options being pursued are reported in Table 2. Three of the tests from the SPM were applied to the program options – the Total Resource Cost (TRC) test, the Participant test, and the Ratepayer Impact Measure (RIM) test. The TRC test considers the Benefits and Costs from society's or the total state of California's perspective. In contrast, the RIM test considers the revenue impact on ratepayers not participating on the tariff or program.

Table 2: Benefit-Cost Ratios of DR Options Compared to a New Peaker[70]

Program/Tariff	TRC	Particip.	RIM
IOU Critical Peak Pricing	15.4	4.8	1.2
SDG&E Hourly Pricing Option	14.7	2.6	0.8
IOU Demand Bidding Program	22.6	1.3	4.6
CPA Demand Reserve	2.2	3.1	1.2

[69] ALJ Ruling, November 13, 2002. The cost of a new peaker was $85/kW-yr and $.035/kWh.

[70] The IOU numbers include technical incentives and bill guarantees and are taken from the March 11, 2003 report of Working Group 2. The CPA numbers are taken from the January 16, 2003 report of Working Group 2 since no new incentives are proposed for the CPA programs. Moreover, the CPA numbers reported here are a weighted (by MW) average of the 3 CPA options reported in the January 16 report.

Partnership

All programs passed all three tests, with the exception of SDG&E's HPO, which did not pass the RIM test. However, some argued that the RIM test is not directly applicable because presumably the HPO better reflects what the true costs of power are than conventional time-of-use rates – and hence participants now joining the HPO are currently subsidizing other customers on the less precise time-of-use rates. Therefore, given the limitations of the tests, all program proposals were judged to be attractive compared to investing in a new peaker of comparable MW size. Under revenue neutrality principles, discussed subsequently, the IOUs will not lose money. Further, since it has become clear that at least an initial rationale for these programs is to develop experience in attracting customers to participate and evaluating their load response when programs are triggered, we believe that these specific tariffs and programs are sufficiently cost-effective to be authorized.

We believe that the concerns expressed by WG2 participants about the validity of the SPM tests, and the process for developing inputs that accurately reflect the value of displaced supply side power procurement costs, are sufficiently important that we will direct parties in Phase 2 of this proceeding to develop and bring forward proposed modifications to the SPM.

2. The Principle of Revenue Neutrality and Recovery of Revenue Shortfalls

There is general agreement that customer participation in demand response tariffs and programs will cause the IOUs to lose revenue (compared to authorized revenue requirement) because load reduction involves both a reduction in energy usage and a shift from energy use during peak periods in which existing rate designs accentuate revenue recovery. The exact amount of revenue loss depends upon many factors, including the nature and extent of customer participation in demand response programs and other unknowns such as offsetting energy purchase cost reductions attributable to effective demand response. In that light, the estimated dollar impacts provided at the end of the WG2 process ($11.5 million in 2003 and $29.9 million in 2004[71]) must be viewed as very conservative approximations, since they assume no short-term commodity procurement cost savings associated with these revenue reductions. Those cost savings certainly will exist, though their magnitude cannot be predicted in advance.

Under the concept of revenue neutrality proffered by the WG2 participants, the IOUs' authorized revenues should be protected from the effects of the actual demand reductions that occur due to demand response.[72] The IOUs recommend recovery of revenue shortfalls from the entire system, asserting that it is burdensome to track such shortfalls by class.

Against this recommendation, ORA argues that such revenue shortfalls should be recovered from the large customer class, not system-wide. Under ORA's proposal, certain revenue shortfalls would be recovered from the non-CPP participants in the same sub-customer class, which will give non-participating (static rate) customers an incentive to switch to CPP or other dynamic tariffs and programs. This proposal is possible due to the likelihood that some customers who volunteer for the CPP pay less under their new tariff without making any change in their usage. This happens because current static

[71] See WG2 Report dated March 11, 2003, Table 5, p. 48. WG1 staff has extrapolated from Table 5 to arrive at these approximate figures for Year 2003 and Year 2004.

[72] See WG2 Report, dated November 15, 2002, p. 29.

rates are designed based on average load profiles, and these customers are currently paying more than their fair share through an intra-class subsidy to users with peak loads greater than the average load. ORA proposes that this structural revenue shortfall (the intra-class subsidy to users with peak loads greater than the average load) be recovered from customers who choose to stay on the default TOU rate. In ORA's view, this will cause an increase in the default TOU rates, thereby encouraging more customers to migrate to the CPP tariff. ORA notes that the "dynamic revenue shortfall," the bill savings resulting from customers changing their loads in response to new prices, is offset by comparable reductions in procurement costs, and ideally net procurement cost savings will be passed through to the cub-class of CPP participants via rate design in the form of lower off-peak prices. ORA believes that CPP rates should be designed so that the dynamic shortfall equals the avoided procurement costs.[73]

We find merit in ORA's proposal designed to encourage program participation by sending appropriate price signals. Effectively, it would cause CPP participants to receive the benefit of the full amount of avoided procurement costs, thus making the CPP rate more attractive. However there are some roadblocks to implementation of ORA's proposal. First, it is unknown how much rates will increase for those customers who stay on the default rates, as part of the calculation depends upon how many opt for the CPP. Second, there are practical rate-related differences among the IOUs. Specifically, Edison recently filed an application for rate reductions, so an increase to default TOU rates for its customers would be offset. On the other hand, the elimination of PG&E's surcharges is not expected to occur immediately, and SDG&E has no

[73] ORA's Written Comments on the WG2 Reports, dated January 27, 2003, pp. 4 – 6.

current plans to reduce rates. Third, the IOUs do not currently allocate either procurement costs or prospective savings by class or schedule, which is a necessary prerequisite to the ORA proposal. Nonetheless we believe that these practical problems must be weighed against the benefits of the ORA proposal and the likelihood that it will increase participation in demand response programs over the long term. ORA's conceptual proposal merits further exploration. Accordingly, we will require the IOUs to file a compliance filing outlining their assessment of the customer impacts of implementing the ORA proposal; indicating how they would implement both features of the ORA plan (its treatment of structural revenue shortfalls and its treatment of dynamic shortfalls); and identifying the currently available, or next available, ratesetting forum where the ORA proposal may be explored and implemented in the context of the IOU's overall rate design. ORA has requested that a workshop be held prior to the submission of these compliance filings and our order so provides.

Until the ORA proposal can be implemented, we will allocate the revenue shortfalls associated with the programs adopted in this decision on a system-wide basis, consistent with the recommendation of the IOUs and most other WG2 participants.

3. Program Administrative Costs

As shown in Attachment B, program administrative costs, which are comprised of O&M and A&G costs associated with the various activities necessary to implement the adopted demand response programs total $13.0 million and $7.0 million for calendar years 2003 and 2004, respectively. These costs included program monitoring and evaluation expenditures totaling $1.5 million in 2003 and $0.5 million in 2004. All costs attributable to the CPA DRP program should be covered by the IOUs in the following proportions: 45% each from PG&E and Edison, with 10% from SDG&E.

4. Capital Costs

As shown in Attachment B, capital costs for such items as advanced meters, billing system additions or measurement data collection software attributable to the adopted demand response programs total $7.9 million, and $0 for calendar years 2003 and 2004, respectively. $4.5 million of the total $7.9 figure relates to the installation of additional AB29X meters on certain types of willing customers and it is not clear that all of those customers will select such meters. Thus, those capital costs could be considerably less than the amount projected. For purpose of allocation among the utilities, costs related to the CPA DRP program should be allocated 45% each to PG&E and Edison, with 10% to SDG&E. Additional metering costs should be allocated at $2.5 million for PG&E, $1.5 million for Edison, and $0.5 million for SDG&E, with the proportional higher amount available to PG&E due to the number of agricultural customers in its territory with demands over 200 kW that do not yet have interval meters.

5. The Costs of Incentives

With our decision to approve only the professional technology assistance incentive, costs in this expenditure category for calendar years 2003 and 2004 are significantly reduced from the $11 million originally proposed to $3.41 million ($2.0 million in 2003 and $1.4 million in 2004).

There are expenditures shown in Attachment B as “other incentives” capped at a total of $0.9 million and $0.9 million in calendar years 2003 and 2004, respectively. These are the expenditures authorized in this decision for this category. In addition, Attachment B lists, for purposes of completeness, certain incentives already approved in the DWR revenue requirement (i.e., not authorized in this decision) related to the CPA DRP program. The total amount for 2003 is $12.75 million and for 2004 is estimated to be $25.5 million.

Adding the total transitional incentive costs authorized to the "other incentives" not applicable to CPA and covered in the DWR revenue requirement yields total incentive costs of $2.9 million in 2003 and $2.3 million in 2004.

6. Imposition of Cost Cap

The costs (Program Administrative, Capital and "Other Incentive" Costs from the discussion above) for the demand response programs authorized in this decision for calendar years 2003 and 2004, are capped at the total amount of $23.7 million and 9.3 million, for calendar years 2003 and 2004, respectively. This total figure, $ 33.0 million, is exclusive of revenue shortfalls and CPA DRP costs, which are part of the DWR revenue requirement.

7. Cost Recovery Mechanisms

The respondent IOUs requested identical cost recovery mechanisms for programs adopted as a result of both WG2 and WG3. Consequently in our recent decision (D.03-03-036) dealing with WG3 issues, we adopted cost recovery mechanisms that apply to all Phase 1 programs, both those advanced by WG3 and WG2. Therefore it is unnecessary to address cost recovery mechanisms again in this decision.

J. Customer Education/Outreach

In the March 11th Report the WG2 participants have presented an implementation plan which builds upon the detailed Customer Marketing, Education and Recruitment Plans included in the December 13, 2003 WG2 Report. This plan assumes that the IOUs will assume the responsibility for marketing the adopted CPP/HPO and DBP programs to their large customers. As proposed, customer education includes extensive training for utility employees who have customer contact responsibilities, as well as development of customer education materials and education sessions, all designed to provide general familiarity with the adopted programs, program benefits, bill information, sign-up requirements, and enrollment procedures.

As proposed, marketing and recruitment efforts will emphasize higher potential customers, including those not currently participating in demand response programs but who have participated in them in the past; and commercial and industrial customers whose operations offer peak load shifting opportunities. Some customer contacts will be made by phone, direct mail, or selected event participation. In addition, each IOU proposes to place CPP and DBP program information on its website. Throughout the life of these programs, communication with customers will continue via various program communication letters and ongoing one-on-one customer contact.

While adopting the WG2 customer education / outreach proposals in concept, we will also impose some requirements. We will require the IOUs to implement substantially similar customer education and outreach programs for the CPP / HPO and DBP; further these programs must be compatible with parallel activities of the CPA for its DRP programs. Marketing of incentives requires particular care so that incentives are not over-emphasized. We prefer to attract customers with as little use of incentives as is feasible in order to minimize costs, and in recognition of the fact that these incentives are not an intrinsic part of the tariffs, but merely a transitional tool. In connection with the adopted technical assistance rebate, professional technical assistance incentive certification and verification of load reduction should be handled by firms designated by the CEC. The IOUs should coordinate with the CEC to make every attempt to attract customers to these demand response programs who already have received subsidies from the state for installation of demand response equipment.

The customer education proposal submitted by WG2 leaves many specific implementation details to be resolved over time. We will not leave the resolution of these details to the sole discretion of the IOUs. Rather we will continue the WG2 collaborative process, allowing those parties who are interested in these implementation details to fully participate in honing them. And in the event there are disputes, we expect the WG2 facilitator initially to attempt to resolve them with the parties, but in the event that proves impossible, the WG2 facilitator will bring the matter to the attention of the assigned ALJ who will resolve the matter in consultation with the assigned commissioner.

K. Program Evaluation, Monitoring and Oversight

WG2 has proposed a comprehensive monitoring and evaluation plan.[74] Specifically, the monitoring plan would include recruitment and sign-up; tracking continuity; measuring actual patterns of demand response; IOU revenue impacts; participant expenditures; administrative costs; and reporting monitoring results. The evaluation plan will include such elements as identifying the nature of the participants; assessing load shape changes; understanding how to accomplish load impacts; estimating system benefits; estimating IOU revenue and cost impacts; and assessing whether tariff or program changes are necessary. The costs of the comprehensive measurement and evaluation plan are estimated at $861,000, and $275,000 for 2003 and 2004, respectively (see Attachment B). Supplemental research for adopted incentives is

[74] See, Working Group 2 Report dated December 13, 2002, pp. 24 – 29, and Working Group 2 Report dated March 11, 2003, pp. 37-39.

also contemplated. WG2 proposes to supplement the plan to monitor the use of these incentives and gauge their effectiveness. Specifically the supplement will assess how successful the rate protection incentive is in overcoming customer specified barriers to wider CPP and HPO acceptance, in increasing initial enrollment in these programs, and in leading to second year enrollments. It would also include analysis of customer preferences for alternative incentive packages, the overall effectiveness of the incentives in producing the desired results, and comparative load reductions of those accepting the incentive vs. those who chose not to. Monitoring would be broadened to include reporting on the number of customers signed up for the rate protection incentive and the number and amount of true-up payments made after the first 12 months on the CPP or HPO tariff.[75]

WG2 participants also propose to monitor the technical assistance incentive designed to increase enrollment in the CPP and HPO tariffs as well as the IOU DBP. They plan to separately track and assess this incentive. There will be reporting on the number of sign-ups, the load reductions represented, and the incentive payments made. In addition, WG2 proposes to include the assessment of impacts of installing a variety of sub metering and data-logging devices on a sample of the technology-assisted customers, representing a broad range of customer types. Sub-metering and data-logging data will be correlated to total building loads and analyzed to determine how specific technologies contribute to total building load reductions. Costs for this effort include acquisition, installation, and removal of monitoring equipment; data collection and management; and data analysis and reporting. The CEC will supervise this work

[75] Working Group 3 Report dated March 11, 2003, p. 38.

in coordination with the IOUs and the Energy Division. The costs of augmenting the comprehensive measurement and evaluation plan to assess the rate protection plan and incentives are projected to be $125,000 for 2003 and $250,000 for 2004 (see Attachment B), but these costs may be slightly higher than actual costs as they include the technology incentive which is not approved in this decision.

We are especially interested in monitoring and evaluating the impact of the incentives approved in this decision, so we will approve the supplemental work suggested by WG2 in that area, as part of our overall approval of the plan as described above. The $460,000 estimated for this work is reflected in Attachment B. We also believe the CEC and the Energy Division must play a key role in the monitoring and evaluation process, as reflected in the WG2 proposal. And it is abundantly clear that an important coordination effort is needed to ensure that the appropriate data is collected and made available for analysis to support programmatic evaluation. The WG2 facilitator is designated to work with the IOUs and parties who wish to be included in this effort, to maintain the required level of coordination, including review of implementation plans, fine tuning of program implementation mechanics within the scope of this decision, and review of compliance filings or tariffs that may be required. In the event of disagreement that cannot be resolved within the WG2 process, the facilitator will bring the matter to the attention of the assigned ALJ who will resolve the matter in consultation with the assigned commissioner.

WG2 has suggested that Fall 2004 be a major point to evaluate the authorized tariffs and programs, but this decision has authorized tariffs without expiration dates and extended the period in which incentives can be offered through calendar year 2004. We will direct the IOUs, in coordination with the CEC, to conduct evaluation activities to be completed in the Fall of 2004, as input to a systematic review of demand response policy, tariff development, and program design to be conducted in the winter of 2004/2005.

V. Phase 2 of this Rulemaking

The Assigned Commissioner will issue a ruling scoping Phase 2 of this proceeding at the earliest opportunity. Such ruling will detail the issues to be addressed, and a timetable for their resolution, and will address the need, if any, for evidentiary hearings on some issues.

VI. Comments on Draft Decision

The draft decision of the ALJ was mailed to the parties in accordance with Pub. Util. Code §311(g) and the Commission's Rules of Practice and Procedure. On April 28, 2003, fourteen parties[76] filed opening comments, and on May 5, 2003, five parties[77] filed replies. We have considered the parties' views in light of the requirement that comments must focus on factual, legal, or technical errors in the draft decision, and that comments merely rearguing parties' positions will be accorded no weight (Rule 77.3). Consistent with Rule 77.3, and based on the current state of the rulemaking record, we have made various changes to the draft decision designed to strengthen its technical accuracy. These revisions range from the correction of minor typographical errors to more detailed changes that alter outcomes, as listed below and reflected throughout the decision.

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[76] Opening Comments were filed by: ACWA, BOMA, Joint Commenters (comprised of CCEA, the Silicon Valley Manufacturers' Group, and the Alliance to Save Energy), CLECA, CMTA,CUE, the Demand Reserves Providers, DGS, Echelon, ORA, PG&E, SDG&E, SCE, and TURN. The Joint Commenters' Motion for Acceptance of Late Filed Comments is hereby granted the comments were distributed to parties on the service list electronically on the actual due date. Echelon's Petition to Intervene for the purpose of having its comments considered on the technology incentive issue is hereby granted.

[77] Reply comments were filed by CCEA, ORA, PG&E, SDG&E, and SCE.

A. Revisions: Program Details

We make certain technical revisions to Attachment C to clarify the CPP. First, the number of CPP operating days is 12 per year, except for summer of 2003 where there will be a proration due to implementation timing concerns. We also make technical revisions to both Attachment C and Attachment E (governing the IOU DBP program) to ensure consistency in the baseline calculation. Finally, we revise Attachment E (§1.22, §1.27, and §1.5) to ensure that it contains certain critical features of the DBP.

Given respondents' concerns about the complexities of integrating the CPA DRP into the IOUs' procurement and scheduling processes, we allow more time and a phased implementation approach (Ordering Paragraphs 8 and 9).

In response to comments, we allow the parties additional flexibility in their efforts to develop an RTP tariff in this proceeding (Finding 21; Ordering Paragraph 10).

B. Revisions: Customer Participation Issues

In response to comments noting that the record is not well-developed on the issue of agricultural customer participation, we limit the extension of the agricultural customer participation to a set of existing tariff schedules for PG&E and SDG&E. We require Edison to file a compliance filing detailing the tariff schedules they propose to include for agricultural participation. In doing so, we reject Edison's proposal that it transfer participating agricultural customers to discrete commercial accounts.

We adopt a set of conditions governing multiple meters at one customer site, as suggested by PG&E and others. We clarify the definition of customer site for purposes of multiple meter situations.

Finally, we make clarifying changes in connection with the bill protection incentive for CPP, extending the protection period from 12 to 14 months in order to provide customers protection during events that will be called through the fall of 2004. Conforming changes are made to Attachment C.

C. Revisions: Program Costs and Related Cost Issues

We have required the utilities to submit proposals to implement the ORA revenue shortfall proposal. In response to a suggestion made by ORA in its comments, we provide for a workshop moderated by Energy Division staff, to be held prior to the filing of the utility implementation proposals.

Attachment B has been revised to clarify that capital costs related to additional meters apply to all program offerings authorized in this decision. We also add additional columns to clarify costs already included in DWR's revenue requirement, as well as anticipated revenue reductions to the IOUs from customer participation in the programs or tariffs.

D. Revisions: Program Evaluation and Monitoring Oversight

We also correct an oversight in the draft decision, and include the $460,000 estimated cost of supplemental work suggested by WG2 in connection with an in-depth assessment that includes collecting quantitative information on how specific technologies performed in achieving demand reductions.

To facilitate the comprehensive monitoring and evaluation plan, we add a requirement that the IOUs provide all data and background information needed by those involved in the evaluation process, under appropriate confidentiality protection.

VII. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Lynn T. Carew is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The strategic development of demand response capability in the California energy market requires coordination among this Commission, the CEC, and the CPA; to meet this responsibility, these state agencies have used an interagency working model and three working groups to develop the record in Phase 1 of this rulemaking.

2. Throughout Phase 1, decisionmakers from the CPUC, CEC and CPA (the "Working Group (WG) 1 principals") provided policy guidance to a group of active parties interested in large customer demand response issues ("Working Group 2 or WG2"), encouraging WG2 to develop a tariff or set of tariffs for use by large customers with average monthly demands of 200 kW and above, and to strive for "quick wins" that would take advantage of two key factors: the fact that 1) many large customers have interval meters in place due to AB29X, and 2) Summer 2003 presents conditions ideal to test how large customers who have such meters will respond to time-sensitive rates.

3. WG2 held thirteen noticed workshops, open to all active parties and facilitated by staff supporting the Working Group 1 principals, and during the period November 15, 2003 through March 11, 2003, WG2 produced four written reports. The participants attempted to develop consensus around a set of dynamic pricing proposals, but the diversity of opinion on key issues ultimately worked against the development of consensus on a "quick win" for Summer 2003.

4. The WG1 principals have developed a long-term vision and set of goals for demand response to help guide the efforts of participants in this proceeding. The vision statement provides a definition and simple goal statement, followed by

objectives (reliability, lower power costs, and environmental protection), goals and principles (customer service, optionality, technology issues, IOU issues, and coordination), and a timeframe (phases for proof-of-concept, phased implementation for large customers, and residential implementation). This is an evolving document and work-in-progress, although several aspects of the vision require explicit Commission endorsement.

5. The vision statement sets a goal of meeting IOU capacity needs of 5% of system peak demand by 2007 through demand response, thereby requiring the Commission to set interim MW targets. An explicit linkage between these targets and the IOUs' procurement-related obligations included in the procurement plans filed in R.01-10-024 is required.

6. There is agreement that achievable goals are as follows: for calendar year 2003: 150 MW for PG&E, 150 MW for Edison, and 30 MW for SDG&E; for calendar year 2004: 400 MW for PG&E, 400 MW for Edison, and 80 MW for SDG&E; for calendar year 2005: for all IOUs, 3% of annual peak demand for bundled service load; for calendar year 2006: for all IOUs, 4% of annual peak demand for bundled service load; for calendar year 2007: for all IOUs, 5% of annual peak demand for bundled service load.

7. The WG2 participants have been unable to develop one consensus tariff proposal given the diversity of views among large customer interests, respondents, and other parties.

8. Since no single demand response program or tariff satisfies all large customers, a portfolio or "mix" of demand response programs that will appeal to the greatest number of customers.

9. While recognizing that mandatory tariffs/programs for large customers would produce the greatest demand response, it is reasonable to authorize voluntary program participation for large customers in the near term. Not all

large customers are capable of immediately altering their manufacturing or production processes in order to respond to dynamic pricing tariffs and forcing their participation at this point will have serious unintended repercussions for the California economy.

10. The Association of California Water Agencies (ACWA) presented a Critical Peak Pricing (CPP) proposal widely regarded as a “no-lose” proposition as customers who do not respond pay no more than their current demand charges. Given our goal to develop programs providing meaningful demand response, and the fact that ACWA’s proposal provides generous bill savings to participants who provide little or no demand response in return, there is legitimate concern that ACWA’s proposal does not provide a meaningful demand response resource.

11. The IOUs present a joint CPP proposal designed to appeal to commercial office buildings and other similarly-situated customers with large air conditioning loads, to be offered to large customers (>200 kW per month), most of whom are already equipped with interval meters due to Assembly Bill 29 of the first extraordinary session of 2000-2001 (AB29X).

12. The City and County of San Francisco (CCSF) seeks to intervene in this proceeding out of concern that the statewide joint proposal does not adequately capture San Francisco’s peak load profile.

13. It appears that the load, demand, and capacity characteristics of the San Francisco peninsula are unique in the PG&E territory and merit special consideration, although CCSF’s broader concerns about transmission constraints and local generation issues are beyond the scope of this proceeding.

14. While the joint CPP proposal does not enjoy universal support, it is apparent that no single program appeals to all large users. The joint CPP proposal involves a relatively modest expenditure through 2004, provides

customer choice, and also allows us to take advantage of the AB29X infrastructure already in place. Modifications to the Joint CPP Proposal allowing agricultural customer participation, certain multiple meter situations, multiple program participation, and the use of incentives, are designed to promote greater participation in this program.

15. There is no record for adopting SDG&E's proposal to expand the Joint CPP proposal to an additional 6700 customers whose usage spans 20 kW to 200 kW. Instead it is reasonable to confine the CPP program to SDG&E customers whose usage exceeds 100 kW, consistent with D. 01-05-032, wherein we authorized SDG&E to procure, install and operate real time meters for each of its customers (except exempted agricultural customers) with peak demand of 100 kW or more.

16. SDG&E's proposal to convert its existing pilot program, the Hourly Pricing Option (HPO), into a full-scale program has merit because the HPO, as modified, breaks new ground by expanding the hourly prices to semi-peak periods and expanding the number of hours for which hourly rates are revealed to the participant.

17. In order to add another type of demand response offering to the portfolio of offerings available to large customers, the IOUs propose to continue the existing Commission-authorized reliability-based demand bidding program, and also expand available demand bidding options, allowing participants to reduce demand voluntarily when requested by the IOUs in one of two ways: via 1) a price trigger, and 2) a system emergency trigger.

18. A customer-specific 10-day rolling average energy usage baseline, calculated "using the average of energy usage for the three highest days for the same hour during the past ten similar days prior to a DBP event" will be used to determine performance, as a means to address concerns that a simple 10-day

rolling average may negatively bias temperature-sensitive customer loads. This determination should be made using a consistent methodology using the average of the highest kWh usage consumed over a specific period. For the CPP, the determination of a "high" day shall be based on the total kWh usage consumed over the peak period. For the DBP, the determination of a "high" day shall be based on the average per-kWh consumption over the bid duration period.

19. The DRP offered under the aegis of the CPA assists in meeting our stated demand goals because it is available to a much broader array of participants than the IOUs' DBP, which is limited to bundled customers. DRP is the one offering that is available to direct access customers, a group whose participation in demand response programs is key to meeting statewide goals.

20. The Transmission and Distribution (T&D) Peak Capacity Proposal is presented as a pilot program for implementation in Summer 2003. It is designed to allow both direct access and bundled customers above and below 200 kW in T&D constrained areas to receive financial benefits in the form of reduced T&D charges when they take actions that provide benefits on constrained T&D systems. However the pilot description is very general, as are the specific concepts to be tested, and there is insufficient time to develop hourly prices for T&D constraint costs as inputs to this Summer 2003 demand response program.

21. Time did not permit the full exploration of the Infotility real time pricing (RTP) proposal, designed to test or identify 1) customer interest and response to a real time price signal across multiple building types; 2) customer preferences for baseline methodologies; 3) specific customer education requirements prior to participation in a two-part RTP tariff; 4) technical and administrative barriers to a full roll out; 5) customer satisfaction; and 6) "lessons learned." However there is keen interest among the active parties in developing a two-part RTP pilot or pilots or alternatives, which may use the Infotility proposal as a starting point.

22. Balancing our goal of maximizing participation in demand response programs against cost concerns, we will allow certain agricultural customers whose usage exceeds 200 kW to participate in the offerings authorized, if they currently have interval meters in place.

23. In furtherance of our desire to ensure the participation of agricultural customers in demand response programs, it is appropriate to require the respondents to provide accurate cost data relative to such participation by those agricultural customers who currently do not have interval meters in place.

24. A liberal meter aggregation policy will encourage participation, but that goal must be balanced against the unknown metering costs and our present lack of knowledge about small commercial customer demand response. Thus, we are not adopting an aggregation policy in this decision, but will explore the issue in Phase 2 of this proceeding. Instead, at this time, it is appropriate to limit participation by customers with multiple accounts to those situations where at least one meter of a multi-meter facility is already >200 kW and where an individual site is defined as in the applicable utility tariff rules.

25. Multiple program participation raises several concerns including two key ones: the possibility that customers will be compensated multiple times for the same load response and the possibility that potential load relief associated with a particular program will be double-counted.

26. There is significant customer inexperience with price-triggered demand response programs and a reluctance to spend the time and effort necessary to participate in these programs, as well as perceived risks about participation. Transitional incentives are one method to increase customer participation levels by overcoming these concerns.

27. The bill protection incentive available to those participating in the CPP and HPO programs will provide 100% bill protection, meaning that the

participant pays no more than they would have had they remained on their original rate schedule, for the first fourteen months they are on the CPP or HPO tariff, but no later than December 31, 2005.

28. Under the bill protection incentive, the customer must actually reduce peak demand by a minimum of 3% per CPP event, averaged over the course of their fourteen-month participation. If they do not do so, they will not receive credit at the end of fourteen months. For customers on the HPO tariff, the 3% reduction could be averaged over the entire time period of the customer's participation.

29. The bill protection option involves nearly no cost, as long as existing revenue requirements are established and shortfalls are collected through appropriate balancing mechanisms.

30. WG2 also proposed a technology incentive for participants in the CPP and HPO tariffs, as well as the IOUs' DBP, which would allow a rebate for installation and use of pre-approved technology that enhances the customer's demand response. This transitional incentive would rebate up to $150/kW of curtailable on-peak load for a combination of costs associated with receiving professional technical advice and installing unspecified qualifying hardware. Payments would not made for technical assistance that does not lead to load reduction as 50% of the potential payment is paid only after the customer achieves certain performance targets. Funding for the CPP/HPO technical incentive is proposed at $11.375 million, with an additional $8.249 million for the IOUs' DBP.

31. While an equipment-based rebate is potentially helpful in augmenting demand response, the proposal lacks key detail, including a method for determining what constitutes "qualifying" technologies.

32. The level of projected costs for the technology incentive exceeds $11 million, a significant amount, with no indication of how much demand response such expenditure may encourage. This fact is not counterbalanced by the requirement that would withhold 50% of the incentive in cases of non-performance.

33. The level of expenditure associated with the technology incentives, coupled with uncertainty over the likely customer response to these incentives, leads us to reduce the funding and nature of this incentive by confining it to a professional technical assistance component, without authorizing the additional hardware component of the proposed technology incentive package.

34. Approval of the professional technical assistance portion of the proposed technical incentive package, allowing a rebate for professional technical advice regarding installation of new equipment or modification of existing equipment or behavior, may spur customer participation at a more acceptable cost than that associated with the entire proposal for technical incentives.

35. In this decision we take several steps designed to augment customer participation in the adopted programs, including opening the tariffs and programs to certain agricultural customers, allowing certain multiple-meter situations, allowing multiple program participation in certain circumstances, as defined, and approving bill protection and professional technical assistance incentives. These actions will augment the expected MW demand response targets for 2003 and 2004 shown in Appendix B.

36. Our decision to reject the technology hardware portion of the transitional incentive proposal may diminish to some degree the expected MW contribution detailed in Appendix B related to the statewide CPP, HPO, and IOUs' DBP.

37. Because it has been the standard for rate design and demand-side management measure evaluation historically, the most relevant standard for

determining cost-effectiveness for tariffs and programs designed to be part of a growing reliance upon demand response is the cost of a new peaker power plant.

38. Using several tests from the Standard Practice Manual, all programs authorized in this decision are cost-effective, except SDG&E's HPO, which did not pass one of the tests. However, given the limitations of the tests, all program proposals are attractive compared to investing in a new peaker of comparable MW size.

39. Customer participation in demand response tariffs and programs will cause the IOUs to lose revenue (compared to authorized revenue requirement) because load reduction involves both a reduction in energy usage and a shift from energy use during peak periods in which existing rate designs accentuate revenue recovery. The exact amount of revenue loss depends upon many factors, including the nature and extent of customer participation in demand response programs, and other unknowns, such as offsetting energy purchase cost reductions attributable to effective demand response.

40. The estimated revenue shortfall impacts discussed in this decision are very conservative approximations because they assume no short-term commodity procurement cost savings associated with these reductions, and such savings certainly will exist, although their magnitude cannot be predicted in advance.

41. There are starkly differing recommendations regarding recovery of revenue shortfalls in this proceeding: the IOUs recommend recovery of revenue shortfalls from the entire system, whereas ORA argues that such shortfalls should be recovered from the large customer class(es), not system-wide. Under ORA's proposal, certain revenue shortfalls would be recovered from the non-CPP participants in the same sub-customer class, which will give non-participating (static rate) customers an incentive to switch to CPP or other

dynamic tariffs and programs. There is merit in the ORA proposal, because it is designed to encourage program participation by sending appropriate cost signals. However, there are some near-term practical impediments to the adoption of ORA's proposal, as discussed in this decision.

Conclusions of Law

1. Phase 1 of this rulemaking has proceeded via notice and comment rulemaking, without the need for evidentiary hearings. The decisionmaking record consists of respondents' formal demand response programs/pricing options filed in compliance with the OIR; the official transcripts of five formally noticed WG1 meetings; the rulings following those meetings and written comments thereon; and the four WG2 reports and related rulings and written comments.

2. The tariffs and programs being developed in this proceeding should be explicitly linked with procurement planning in R.01-10-024.

3. The ACWA CPP proposal should not be adopted as it would provide generous bill savings to participants providing little or no demand response in return.

4. Since CCSF has demonstrated that it has a direct and substantial interest in the outcome of this proceeding that cannot be represented adequately by any other party, its motion to intervene pursuant to Rule 45 should be granted.

5. The joint CPP proposal should be approved, with certain modifications, because it involves a relatively modest expenditure through 2004, provides customer choice, and also allows us to take advantage of the AB29X infrastructure already in place.

6. SDG&E's proposal to convert its HPO pilot into a full-scale program and modify it by expanding the hourly prices to semi-peak periods, and expanding

the number of hours during which hourly rates are revealed to participants, offers additional options to customers, and should be adopted. Consistent with D.02-01-062, SDG&E should be permitted to offer this program to customers with monthly demands >100 kW. This outcome should be confined to SDG&E, as efforts are currently underway to develop a two-part real-time tariff for wider application.

7. The IOUs' DBP, as presented in the March 11, 2003 WG2 Report, should be adopted subject to certain modifications which will improve customer participation, as discussed in the text of this decision relative to multiple participation, multiple-meter situation, and inclusion of certain agricultural customers.

8. The CPA DRP should be adopted because it is available to a much broader array of participants than the IOUs' DBP, and is the one offering that is available to direct access customers, whose participation in demand response programs is key to meeting statewide goals.

9. IOUs should be able to dispatch from either demand bidding program, the IOU DBP or the CPA DRP, as both programs will be available to large customers.

10. Multiple program participation in the adopted programs should be allowed, provided that there are acceptable guidelines designed to avoid both double-compensation and double-counting, to the extent provided in this decision.

11. Because they meet the guidelines for avoiding double-compensation and double-counting of benefits, the following program combinations should be allowed: CPP and CPA DRP (or IOU DBP); OBMC and CPA DRP; CPA DRP and interruptible rates, subject to limitations discussed in this decision; and CPA DRP spot market options and interruptible rates, subject to limitations discussed in this decision.

12. The bill protection incentive, as modified in the preceding discussion to extend from twelve to fourteen months, should be approved for customers participating in the CPP and HPO tariffs.

13. Given its high cost, lack of key detail, and uncertainty regarding how much customer participation, and therefore demand response, it will engender, the technology equipment portion of the technology incentive should not be approved.

14. A modest rebate in the amount of $50/kW of curtailable on-peak load for the costs associated with receiving professional technical assistance (related to the installation of new equipment or the modification of existing equipment or behavior) that leads to actual demand response, should be authorized.

15. In order to achieve demand response program stability, the programs authorized in this decision should be available well beyond calendar year 2004, and have no expiration date, although funding is authorized in this decision through calendar year 2004.

16. Since there are no remaining customers enrolled under PG&E's experimental real-time pricing tariff, Schedule A-RTP, and the joint proposal submitted in Phase 1 is a reasonable successor to that tariff, PG&E's Schedule A-RTP should be eliminated.

17. Since rate Schedule E-PBIP, a pilot authorized in D.02-04-060, has only one participant, and the WG2 participants see little harm in eliminating the pilot, the single participant should be encouraged and assisted to join another program or tariff and this tariff should be eliminated.

18. Notwithstanding the limitations of the tests from the standard practice manual, it is apparent that all of the programs and tariffs authorized in this decision are attractive when compared to investing in a new peaker power plant

of comparable MW size; therefore, these specific tariffs and programs are sufficiently cost-effective to be authorized.

19. Given the concerns expressed by WG2 participants about the validity of the standard practice manual (SPM) tests, and importance of the process for developing inputs that accurately reflect the value of displaced supply-side power procurement costs, the parties should develop and advance proposed modifications to the SPM in Phase 2 of this proceeding.

20. Since ORA's conceptual revenue shortfall proposal merits further exploration, we should require the IOUs to make a compliance filing outlining their assessment of the customer impacts of implementing the ORA proposal.

21. The IOUs should be required to implement substantially similar customer education and outreach programs for the CPP / HPO and the DBP. Further, these programs should be compatible with the parallel activities of the CPA for its DRP.

22. In connection with the adopted technical assistance rebate, professional technical assistance, incentive certification, and verification of load reduction, should be handled by firms designated by the CEC. The IOUs should coordinate with the CEC to make every attempt to attract customers to these demand response programs who have already received subsidies from the state for installation of demand response equipment.

23. The comprehensive monitoring and evaluation plan proposed by WG2 in its December 13, 2002 report, as augmented by its March 11, 2003 report, should be adopted, in order to identify the nature of those participating in the adopted programs, assess load shape changes, understand how to accomplish load impacts, estimate system benefits, estimate IOU revenue and cost impacts, and assess whether tariff and program changes are necessary. WG2's proposal to supplement the monitoring and evaluation plan to assess the success of the bill

protection and technical assistance incentives under the supervision of the CEC, should also be adopted.

O R D E R

IT IS ORDERED that:

1. We hereby adopt the demand response goals enumerated in Table 1 for each IOU. To ensure that these goals are achieved, we direct the respondent IOUs to do the following:

   a. Take all appropriate steps to implement the dynamic pricing tariffs and programs adopted in this proceeding in order to achieve these goals;

   b. Recommend, as a result of monitoring and evaluation efforts, changes to the tariffs and programs adopted here, as well as additional tariffs and programs, to improve the cost-effectiveness of demand response activities;

   c. Include the MW targets for calendar years 2003 through 2007 in their procurement plans to be filed in R.01-10-024. To the extent that this decision is adopted after those plans are filed, the IOUs shall supplement or augment their filings in R.01-10-024 to reflect this requirement, including, in particular: numeric targets coinciding with the findings in this decision; documentation of the amount of demand response (price-triggered) to be achieved by July 1 of each calendar year (with the exception of 2003, where the goals shall be met by the end of the calendar year); which programs and/or tariffs the IOU will rely upon to achieve the targets; and a contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals;

d. Work with state agencies and the Independent System Operator (CAISO) to ensure that demand response programs and tariffs are appropriately considered in any resource adequacy or reserve requirements and emergency response activities.

2.The motion of the City and County of San Francisco (CCSF) to intervene in this proceeding is hereby granted. PG&E shall work with CCSF to create a localized marketing and recruitment area and triggering conditions for the existing CPP tariff proposal. PG&E and CCSF shall file and serve an advice letter containing the details of this localized plan within 30 days of the date of issuance of this decision.

3.The IOUs' joint Critical Peak Pricing (CPP) proposal is hereby authorized, subject to certain modifications relating to specific agricultural customer participation, multiple meter situations, multiple program participation, and the use of incentives.

4.SDG&E's proposal to convert the Hourly Pricing Option (HPO) approved in Resolution E-3782 into a full-scale tariff, and to modify HPO by expanding the hourly prices to semi-peak periods, is hereby adopted for SDG&E alone.

5.Consistent with D.01-05-032 SDG&E is authorized to offer its authorized CPP and HPO tariffs to customers with peak demands of 100 kW or more, consistent with the text of this decision.

6.The IOUs' Demand Bidding Program (DBP) as presented in the March 11, 2003 WG2 Report, is hereby adopted, subject to the following modifications: First, under circumstances specified elsewhere in this decision, we allow customers to participate in both the CPP and the IOU DBP. Second, we permit some multiple-meter situation, under guidelines detailed subsequently in this decision. Third, for the reasons discussed in this decision, we include in the DBP certain agricultural customers whose usage exceeds 200 kW and who have interval meters in place.

7.The CPA's Demand Reserves Program (DRP) is another type of demand bidding program that is available to large customers, as provided in this decision, which IOUs may use to satisfy their demand response goals established herein.

8.The IOUs shall immediately develop with the CPA and the Department of Water Resources (DWR), as necessary, a mutually acceptable interim mechanism for allocating the CPA DRP resources that they schedule in 2003 with the CAISO. IOUs and CPA shall also develop a permanent proposal, based on the experience in Summer 2003, unless such an alternative mechanism is developed in the procurement proceeding. Within 120 days of the date of issuance of this decision, the IOUs shall file and serve a joint compliance filing containing this information.

9.Within 30 days of the date of issuance of this decision, the IOUs shall file and serve an advice letter with the Commission's Energy Division containing their DRP implementation plan. The issues of operation and scheduling of CPA's existing programs and new multiple program combinations cannot all be resolved immediately, so we require the plan to describe how these concerns can be addressed and solved in phases. The preparation of the plan shall be coordinated with the CPA. Phase 1 of the plan shall include, at a minimum, how the IOUs will coordinate their procurement scheduling activities with the CPA DRP Call Option subprogram in order to ensure that the DRP resources are used when it is cost effective to do so, as well as other efforts to be implemented in summer 2003. The plan shall also contain a timeline identifying when additional phases are expected to start and describe, in a manner acceptable to CPA, the details of the implementation of those phases.

10.In concert with the WG2 participants, the respondent IOUs shall develop a pilot or pilots or consider alternatives, which may use the Infotility pilot proposal as a starting point, testing two-part RTP tariff design features under a schedule to be determined. The cost of the two part RTP pilot(s) or alternatives authorized in this decision shall not exceed $2.8 million, and the actual costs of the pilots or alternatives shall be recorded and recovered using the cost recovery mechanisms authorized for the Statewide Pricing Pilot authorized by this Commission in D. 03-03-036. Before initiating any two-part RTP pilot(s) or alternatives, the respondent IOUs shall present the details of the proposal in an advice letter filing to the Commission's Energy Division for approval; the advice letter shall include a provision detailing how the IOUs propose to provide informational reports and pilot results to the WG2 participants.

11.Agricultural customers, whose peak demand exceeds 200 kW and who have interval meters in place and who are on PG&E's Schedule AG-4 and AG-5, options C and F, or SDG&E's Schedule PA-T-1, are authorized to participate in the programs and tariffs adopted in this decision. Within 15 days of the effective date of this decision, Edison shall define the agricultural schedules to be eligible in its territory. Within 45 days of the date of issuance of this decision, in preparation for Phase 2 of this proceeding, respondents shall file and serve in this docket a compliance filing detailing the projected cost of allowing agricultural customers whose usage exceeds 200kW and who currently lack interval meters to participate in the specific demand response programs authorized in this decision.

12.Participation by customers with multiple accounts in the tariffs and programs adopted shall be limited to those customer sites where at least one meter of a multi-meter facility, as defined in the applicable utility tariff rules, is already >200 kW.

13.The following program combinations shall be permitted: CPP and CPA DRP (or IOU DBP); OBMC and CPA DRP; CPA DRP and interruptible rates, subject to limitations discussed in this decision; and CPA DRP spot market options and interruptible rates, subject to limitations discussed in this decision.

14.The bill protection incentive for customers participating in the CPP and HPO tariffs, as proposed by WG2 to include the performance requirement, the site visit requirement, and the 12-month participation requirement, is hereby approved; in its tariff filing, SDG&E shall specify the exact nature of the performance requirement for HPO customers.

15.A maximum of $50/ kW for professional technical assistance (related to the installation of new equipment or modification of existing equipment or behavior), that leads to actual demand response by customers participating in the CPP/HPO tariffs or IOU DBP, is hereby authorized. The participating customer shall receive a transitional incentive equal to 50% of the potential payment upon certification of potential on-peak load reductions. The remainder of the incentive (the 50% remainder) shall be paid after the customer has shown a calculated peak demand reduction equal to at least 50% of their estimated load drop per CPP event, as averaged over four consecutive CPP or HPO months, while on the program, and before December 31, 2005. If this minimum level of measured load-shifting does not occur, the customer shall not receive the 50% remainder payment. To determine performance, the kW drop will be determined using the customer baseline proposed in the March 11 WG2 report.

16.In the Fall of 2004, the IOUs shall file evaluations for all tariffs and programs authorized in this decision, as well as those authorized in D.02-04-060 in our interruptibles rulemaking, for the purpose of making any necessary revisions for Summer 2005. Should any tariff or program be proposed for elimination, customers participating in it shall be offered a smooth transition to another program, if at all possible.

17.PG&E's experimental real-time pricing tariff, Schedule A-RTP, is hereby eliminated.

18.The pilot and associated rate Schedule E-PBIP, authorized in D.02-04-060, is hereby eliminated.

19.Within sixty (60) days of this decision, the respondents shall file a proposal to recover net revenue losses from participation in the voluntary CPP tariff from within the class that caused the losses. The proposal shall be reviewed in this proceeding to identify an appropriate forum – Phase 2 or another proceeding -- to address the merits of the proposal. Each proposal shall include:

a. identification of existing or proposed new means of tracking gross revenue losses from CPP participants in each tariff;
b. a description of each element of gross revenue losses, (e.g. structural shortfall from CPP participants who do not respond to CPP signals, revenue shortfall from active CPP participants, etc.);
c. identification of existing or proposed new means of tracking procurement costs avoided by CPP participants in each tariff;
d. identification of methods for periodically estimating the aggregate benefits from market price reductions induced by load reductions of CPP participants and proposed means of allocating these benefits to each tariff;
e. identification of methods for determining net revenue losses allocated to each tariff to be recovered from within that tariff;
f. suggested ratemaking proceedings in which net revenue losses by tariff would be periodically reviewed, approved and used to adjust rates for each tariff with net CPP revenue losses;
g. an estimate of the one-time only and ongoing costs of implementing the proposal.

Prior to these filings, the Energy Division will convene and moderate a workshop to further explore the ORA proposal.

20.Pending a further Commission decision on the ORA revenue shortfall proposal, the revenue shortfalls associated with the adopted programs shall be recovered on a system-wide basis.

21.For the authorized tariffs and programs, aggregate program administrative costs shall be limited to $13.0 million and $7.0 million for calendar years 2003 and 2004, respectively. Aggregate capital costs are limited to $7.9 million and $0 for 2003 and 2004, respectively. Aggregate incentive costs, including "other incentives" not already covered in the DWR revenue requirements, are limited to $2.9 and $2.3 million for 2003 and 2004, respectively.

22.The total cost expenditures authorized as a result of this decision are capped at $33.0 million over the two calendar years, exclusive of revenue shortfalls and costs related to "other incentives" which are part of the DWR revenue requirement. Each IOU shall use the cost recovery mechanisms previously adopted in D.03-03-036 as applicable to all Phase 1 programs.

23.The WG2 customer education/outreach proposals contained in the December 13, 2002 report, as augmented by the March 11, 2003 report, are adopted in principle. The IOUs shall implement substantially similar customer education and outreach programs for the CPP/HPO and the DBP. Further, these programs shall be compatible and coordinated with the parallel activities of the CPA for its DRP. In connection with the adopted technical assistance rebate, professional technical assistance, incentive certification, and verification of load reduction, shall be handled by firms designated by the CEC. The IOUs shall coordinate with the CEC and the Energy Division to make every attempt to attract customers to these demand response programs who already have received subsidies from the state for installation of demand response equipment.

24. The comprehensive monitoring and evaluation plan proposed by WG2 in its December 13, 2002 report, as augmented by its March 11, 2003 report, shall be

adopted. WG2's proposal to supplement the monitoring and evaluation plan to assess the success of the bill protection and technical assistance incentives shall also be adopted. IOUs shall provide all data and background information needed to complete this plan, under appropriate confidentiality protections, as needed, to those involved in the evaluation process. The IOUs shall also make this data available to academic researchers, also under suitable confidentiality protection, to facilitate understanding of demand response. The CEC in coordination with the Energy Division shall supervise this work.

25. The WG2 facilitator is designated to work with the IOUs and parties who wish to be included in the coordination effort that is necessary to ensure that the appropriate monitoring and evaluation data is collected and made available for analysis. These efforts include, among other things, review of implementation plans, fine tuning of program implementation mechanics, and review of compliance filings or tariffs that may be required. In the event of disagreement that cannot be resolved within the WG2 process, the facilitator will bring the matter to the attention of the assigned ALJ, who will resolve the matter in consultation with the assigned Commissioner.

26. The IOUs, in coordination with the CEC and the Energy Division, shall conduct evaluation activities to be completed by the Fall of 2004, as input to a systematic review of demand response policy, tariff development, and program design to be conducted in the Winter of 2004/2005.

27. Any necessary modifications or refinements to tariff or program designs beyond those authorized in this decision that arise during the implementation phase, to the extent they cannot be resolved within the WG2 process, shall be requested by formal motion, filed and served on all parties of record. The assigned ALJ, in consultation with the WG2 facilitator and the Assigned Commissioner, is authorized to make any necessary modifications by ruling.

28. Within ten days of the issuance of this decision, the IOUs shall file advice letters containing the tariffs required to implement the adopted offerings. To the extent the attachments to this decision are more definitive than the decision text, the attachments govern. The following are the offerings, as modified in this decision:

- The Joint IOU CPP proposal, following the parameters specified in Attachment C. SDG&E's tariffs shall reflect the authority granted to it to offer the CPP to its customers with monthly peak demands of 100 kW or more.
- For SDG&E, a tariff implementing the authority granted to it to modify the HPO pilot program approved in resolution E-3782 and convert it into a full-scale tariff, and to offer HPO to its customers with monthly peak demands of 100 kW or more as specified in Attachment D.
- The IOU DBP, as modified in this order and detailed in Attachment E.

29.The protest period applicable to the advice letter required in Ordering Paragraph 28 shall be shortened to 10 days.

This order is effective today.

Dated , at San Francisco, California.

ATTACHMENT A

California Demand Response: A Vision for the Future (2002-2007)

Joint statement for consideration by the California Energy Commission, Public Utilities Commission, and Consumer Power and Conservation Financing Authority

This vision is intended as a broad statement for encouraging demand responsiveness in California. It should be read in the context of maximizing the efficient use of resources, while maintaining the economic vitality of businesses in the state, as well as the health, welfare, and comfort of residential electricity users.

We acknowledge that demand response is one resource among many that may be procured by utilities on behalf of their electricity customers. We also seek to make the most cost-effective investments in demand response from an overall societal perspective.

Finally, this vision is intended as a starting point, and should not be interpreted as prejudging the outcome of analysis and recommendations delivered by the working groups to the policymakers in this proceeding.[78] Further, we intend to use this vision as a guide to our efforts, will continue to reevaluate its validity and assumptions as we progress, and will make any modifications, as necessary and appropriate, when new information becomes available.

Definition

DEMAND RESPONSE gives an individual electric customer the ability to reduce or adjust their electricity usage in a given time period, or shift that usage to another time period, in response to a price signal, a financial incentive, or an emergency signal.

Vision

All California electric consumers should have the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals, by no later than 2007.

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[78] CPUC rulemaking R.02-06-001 on policies and practices for advanced metering, demand response, and dynamic pricing.

Objectives

Reliability

- Timely demand response (within minutes or hours) from customers can offset the need for investment in generation, transmission, and/or distribution
- Demand response activities should be designed to achieve a target of 5% reduction in peak demand by 2007
- Cost-effective demand response should be used to meet a portion of reserve requirements
- Numerous and diverse customers voluntarily reducing or shifting their demand in response to economic signals is preferable to controlled outages during power system emergency situations

Lower power costs

- During high-cost periods, demand response can assist in bringing supply and demand into balance by signaling to the consumer the actual costs of buying power at the margin and/or investing in new power resources, thereby lowering overall wholesale electricity costs for all customers
- Timely demand response can, along with other wholesale market measures, help mitigate wholesale market power and ensure reasonable prices
- To encourage demand response, a long-term objective is designing retail rates that dynamically incorporate the marginal cost of providing electricity service
- Demand response activities and infrastructure should be designed to be cost-effective from a societal perspective

Environmental protection

- Reducing consumer electricity usage during peak periods can help reduce fuel use and therefore overall air emissions by reducing output from marginal generation units
- The agencies' definition of demand response does <u>not</u> include or encourage switching to use of fossil-fueled emergency backup generation, but high-efficiency, clean distributed generation may be used to supply on-site loads

Goals and Principles

Customer Service

- Electric consumers in California should be made aware of the time-variable nature of electricity costs and of general steps they can take to help lower those costs
- All customers that desire it should have greater access to information about their own electricity use, at least weekly or daily, with the option for hourly or more frequent data
- Technologies to enable demand response may also provide other customer service benefits including outage detection and management, power quality management, and other information capabilities
- Demand response programs and tariffs should be designed to be customer-friendly, simple, and easy to understand, as well as to minimize customer confusion and allow for continuity among options

Optionality

- Customers should have the ability to choose voluntarily among various tariff options, including:
  - Very large customers (over 1 MW): Hourly real-time pricing (RTP), critical peak pricing (CPP), or Time-of-Use (TOU) Pricing
  - Large customers (200 kW to 1 MW): CPP, TOU or RTP
  - Residential and small commercial customers (under 200 kW): CPP, TOU or flat rate (the latter with an appropriate hedge for risk protection)
- Customers should also have the option to participate voluntarily in programs where they are paid to provide demand reduction as a dispatchable resource, including:
- In ISO markets: real-time, hour ahead, day ahead, ancillary services, planning reserves
- In retail markets: such programs as direct load control, including air-conditioner or water pump cycling, and controllable thermostats

Technologies

- All customers should be provided an advanced metering system capable of supporting a TOU tariff or better, if cost-effective, and with minimal hardware upgrades necessary to choose among various dynamic tariffs
- All customers who choose to should be able to conveniently access their usage information using communications media (e.g., over the internet, via on-site devices, or other means chosen by the customer and respectful of potential privacy concerns)
- The broadest possible range of metering and communications technologies that can enable demand response should be encouraged (i.e., optionality), but

all technologies should be compatible with utility billing and other back-office systems
- State building code (Title 24) updates provide a cost-effective opportunity to introduce demand response technologies during the construction of new buildings or renovation of existing buildings

Investor-Owned Utility (IOU) Issues
- IOUs should be reimbursed for all reasonable expenditures on infrastructure and administration to enable demand response
- IOUs should be required to procure demand response resources as a portion of their overall procurement portfolio (target of 5% of peak demand by 2007) and as a portion of their reserve requirements beginning in 2004
- IOUs should also be provided an incentive mechanism to encourage the best choices for ratepayers
- Operation of an IOU's overall demand response portfolio should be designed to collect the approved revenue requirement and be revenue neutral to the IOU (e.g., revenues stay consistent with costs), with periodic true-ups as necessary
- All IOU demand response efforts should be periodically evaluated to determine past performance and improve future effectiveness

Coordination Issues
- Effective demand response efforts will require coordination among the agencies promulgating this vision statement, as well as the California Independent System Operator (ISO) and the California Legislature
- Coordination will also be necessary related to:
- IOU procurement planning
- IOU rate design modifications, either in general rate cases, or separate venues
- Energy efficiency (and other public purpose) programs
- Other peak demand reduction programs
- ISO efforts to develop transparent wholesale market pricing mechanisms
- Legislative reports such as required by SB1976 and Public Utilities Code Section 393
- Necessary legislative change to rationalize rate design structures

Timeframe

2003: Proof-of-concept phase
- Policy decision including vision and implementation plan

- Dynamic pricing as a full program option to customers with advanced meters in place (>200 kW)
- Pilot programs implemented to gather further information on smaller customer demand response and tariff or program preferences
- Business cases for phased implementation of universal demand response capability (potentially with automated meter reading technology) developed and evaluated, including cost-effectiveness analysis

2004: Phased implementation begins

- Full menu of demand response programs and dynamic pricing tariffs implemented for large and very large customers
- Small commercial and residential pilot program information evaluated
- Vision and timeframe reevaluated
- Technological options reevaluated, based on pilot program results
- Small and medium commercial customer infrastructure deployment phase begins

2005 and 2006: Residential implementation

- Major mass-market education effort initiated
- Full menu of tariff and program options rolled out to residential customers by the end of 2006

(End of ATTACHMENT A)

ATTACHMENT B

Attachment B

DEMAND RESPONSE TARIFF/PROGRAM COST AND INCREMENTAL REVENUE REQUIREMENTS

Program or Tariff Sponsor	Program Name	Impacts in 2003 (MW)	Program Administration Costs (O&M + A&G) for Calendar Year 2003 (4)	Capital Costs for Calendar Year 2003 (3)	Transitional Technical Incentive Calendar Year 2003	Other Incentives in 2003	Total Amounts Proposed for Approval via R.02-06-001 for 2003	Incentives Already Approved via DWR Rev. Req.	Revenue Reductions from Participants
Joint UDC's	CPP	131	$3,848,000	$400,000	$1,272,717	$0	$5,520,717	$0	$8,267,000
PG&E	DBP	16	$310,000	$164,000	$75,758	$239,417	$789,175	$0	$0
SCE	DBP	34	$684,000	$0	$641,026	$664,957	$1,989,983	$0	$0
SDG&E	DBP	3	$208,000	$7,000	$8,333	$17,652	$240,985	$0	$3,000
SDG&E	HPO	2	$150,000	$140,000	$0	$0	$290,000	$0	$426,000
CPA	DRP	225	$3,700,000	$2,500,000	$0	$0	$6,200,000	$12,750,000	$2,835,000
WG2	2-part RTP	0	$2,655,000	$145,000	$0	$0	$2,800,000	$0	$0
WG2	Additional meters	0	$0	$4,500,000	$0	$0	$4,500,000	$0	$0
WG2	Comp. M&E Plan	0	$861,000	$0	$0	$0	$861,000	$0	$0
WG2	M&E of Incentives	0	$125,000	$0	$0	$0	$125,000	$0	$0
WG2	M&E Data Collection	0	$460,000	$0	$0	$0	$460,000	$0	$0
Total Expenditures/Impacts (1)		411	$13,001,000	$7,856,000	$1,997,833	$922,026	**$23,776,860**	**$12,750,000**	**$11,531,000**
Total Annual Incremental Revenue Req. (2)			$13,001,000	$942,720	$1,997,833	$922,026	**$16,863,579**		
Annualized Benefits (5)							**$36,900,000**		

Notes:

(1) Revenue reductions as a result of participant load shifts/reductions cause revenue shortfalls, but these may be partly offset by power procurement cost reductions.

(2) Assumes a 10% rate of return, with a net-to-gross multiplier of 2 recovered over ten years.

(3) Capital investments for CPA DRP include $2,500,000 to support utility incremental software development for better handling of meter data to support DR customers consistent with ISO practices.

(4) For CPA DRP administrative expenses, $1.6 million is for the IOUs, and $2.1 million is for CPA, of which $500,000 is for The Energy Coalition.
(5) Utility Avoided Costs (UAC) for CPP, DBP, HPO and DRP. UAC is based on costs avoided from building a new peaker plant (a fixed cost of $85 per kW-yr., and a fuel cost of $3.50 per mmBTU). The size of these benefits reflects the positive cost-effectiveness results reported in the WG 2 report dated 3/11/03. The UACs for CPP, DBP and HPO are found in Appendix E of the 3/11 WG 2 report (Both Incentives scenario), while the UAC for the DRP is in Appendix C of the 1/16 WG 2 report, (divided by two for 2003 to reflect a phased implementation over 2003-2004.)

Program or Tariff Sponsor	Program Name	Impacts in 2004 (MW)	Program Administration Costs (O&M + A&G) for Calendar Year 2004 (4)	Capital Costs for Calendar Year 2004 (3)	Transitional Technical Incentive Calendar Year 2004	Other Incentives in 2004	Total Amounts Proposed for Approval via R.02-06-001 for 2004	Incentives To Be Approved via DWR Rev. Req.	Revenue Reductions from Participants
Joint UDC's	CPP	371	$2,642,000	$0	$597,791	$0	$3,239,791	$0	$5,670,000
PG&E	DBP	74	$25,000	$0	$431,818	$67,565	$524,383	$0	$0
SCE	DBP	37	$25,000	$0	$192,308	$444,995	$662,303	$0	$0
SDG&E	DBP	11	$25,000	$0	$50,000	$373,043	$448,043	$0	$0
SDG&E	HPO	11	$50,000	$0	$152,905	$0	$202,905	$0	$794,000
CPA	DRP	450	$3,700,000	$0	$0	$0	$3,700,000	$25,500,000	$23,413,000
WG2	2-part RTP	0	$0	$0	$0	$0	$0	$0	$0
WG2	Additional meters	0	$0	$0	$0	$0	$0	$0	$0
WG2	Comp. M&E Plan	0	$275,000	$0	$0	$0	$275,000	$0	$0
WG2	M&E of Incentives	0	$250,000	$0	$0	$0	$250,000	$0	$0
Total Expenditures/Impacts (1)		954	$6,992,000	$0	$1,424,822	$885,603	**$9,302,425**	**$25,500,000**	**$29,877,000**
Total Annual Incremental Revenue Req. (2)			$6,992,000	$942,720	$1,424,822	$885,603	**$10,245,145**		
Annualized Benefits (5)							**$85,305,000**		

Notes:

(1) see 2003 table above

(2) see 2003 table above

(3) incremental cost is due to levelizing capital expenditures over ten years, see 2003 table.

(4) see 2003 table above

(5) see 2003 table above

(End of ATTACHMENT B)

ATTACHMENT C

ATTACHMENT C
Critical Peak Pricing Tariff

The purpose of the Critical Peak Pricing (CPP) tariff is to achieve demand reductions from customers when electricity supply is low or when spot market power prices are high.

1.1. **Applicability**

1.1.1. This tariff schedule is applicable to bundled service customers in Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) service territories that have demands greater than 200 kW.

1.1.2. This tariff schedule is applicable to bundled service customers in San Diego Gas and Electric (SDG&E) service territory that have demands greater than 100 kW.

1.1.3. Service under this tariff is voluntary.

1.1.4. Customers shall have an advanced metering system (meter, communication pathway, and internet access to data) as installed pursuant to AB29x or its functional equivalent.

1.1.5. Customers on this tariff must agree to allow the CEC or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the program.

1.2. **Critical Peak Events**

1.2.1. There will be –a maximum of 12 critical peak days called per summer.

1.2.2. Critical peak days may be triggered using temperature thresholds, special alerts issued by the California Independent System Operator, forecasts of high spot market power prices, or for testing / evaluation purposes.

1.2.3. The IOUs will adjust their CPP temperature thresholds up or down over the course of the summer for the purpose of achieving 12 CPP operations.

1.2.4. The IOUs may designate separate climatic zones within their territories to account for temperature variation.

1.2.5. Critical peak days will only be called Monday through Friday, and not on holidays.

1.2.6. The summer season is defined according to the utilities' definitions as found in their existing tariffs.

1.2.7. The IOUs shall notify customers of the critical peak day the day before.
1.2.8. Critical peak hours shall be aligned with each IOU's respective commercial peak periods.
1.2.9. For the summer of 2003, the maximum number of critical peak days will be prorated to account for the late starting date.

1.3. Critical Peak Rate Effects

1.3.1. This tariff shall be designed with two time periods during critical peak days, a high-price period and a moderate-price periodof approximately equal duration.
1.3.2. The high-price period energy charge shall be five times the customer's otherwise applicable on-peak energy charge. SDG&E shall use a multiple factor that will closely align its energy charges with the other IOUs (approximately a factor of 10).
1.3.3. The moderate-price period energy charge shall be three times the customer's otherwise applicable partial-peak energy charge**.** SDG&E shall use a multiple factor that will closely align its energy charges with the other IOUs (approximately a factor of 5).
1.3.4. On non-critical peak days, the customer's on-peak and partial peak energy charges shall be discounted such that the critical peak rate schedule is revenue neutral in comparison to the otherwise applicable rate schedules.

1.4. Transitional Incentive Options

1.4.1. Customers on the CPP tariff may select from two types of transitional incentive options: bill protection and technical assistance. Customers may elect to receive one of these incentives, both incentives (sequentially or simultaneously), or none.
1.4.2. Both transitional incentive options shall expire on December 31, 2005.
1.4.3.
1.4.4. The bill protection option shall provide 100% protection (the customer pays no higher than what it would pay under its otherwise applicable rate schedule) for the customer for a maximum of 14 months.
1.4.4.1. The bill protection option shall be capped at a participation level of 500 MWs (200 MWs for PG&E and SCE, 100 MWs for SDG&E).

1.4.4.2. If a customer leaves the CPP prior to the end of their 14 month commitment they shall receive no bill protection for any period they were on the tariff.

1.4.4.3. To receive the benefit of a lower CPP bill, customers shall reduce peak demand by a minimum of 3% per CPP event averaged over the course of the CPP months during the customer's 14 months of bill protection.

1.4.4.4. For the purpose of measuring demand reduction, kW drop is to be estimated as the difference between a customer's specific baseline for that hour and the customer's actual energy usage during that hour. The customer-specific baseline is a 10-day rolling average energy usage determined on an hourly basis, using the average of energy usage for the three days with highest total energy usage during the peak period (excluding other CPP days or other days the customer was otherwise paid to reduce power or the customer was subject to a rotating outage) prior to a CPP event.

1.4.4.5. Bill protection benefits are computed on a cumulative basis at the end of the bill protection period and, if warranted, shall be received as a credit on the customer's bill following the end of the bill protection period.

1.4.5. The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances a customer's ability to respond to curtailment events.

1.4.5.1. Customers shall receive a rebate (not to exceed actual costs) based on no more than $50 per kW of curtailable on–peak load for technical assistance that modifies existing equipment or behavior.

1.4.5.2. Customers shall receive 50% of the rebate upon certification by a professional engineer of potential on-peak load reductions.

1.4.5.3. Customers shall receive the remainder of the rebate after demonstrating peak demand reduction equal to at least 50% of their estimated (projected by the professional engineer) load drop per CPP event as averaged over four consecutive CPP months. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate.

1.4.5.4. The method of measuring demand reduction is the same as described in Section 1.4.4.4.

(END OF ATTACHMENT C)

ATTACHMENT D

ATTACHMENT D
Hourly Pricing Option Tariff

The purpose of the Hourly Pricing Option (HPO) tariff is to provide a day-ahead price signal to create an incentive for customers to avoid peak usage and or shift usage to off-peak periods. The HPO tariff was approved as a voluntary pilot program for SDG&E in August 2002. The existing HPO tariff is modified in the following manner:

1.1. **Applicability**

1.1.1. This tariff schedule is applicable to customers with demands greater than 100 kW in San Diego Gas and Electric (SDG&E) service territory.

1.1.2. Customers shall have an advanced metering system (meter, communication pathway, and internet access to the usage data) as installed pursuant to AB29x, or the equivalent.

1.1.3. Customers on this tariff must agree to allow the CEC or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the program.

1.2. **Hourly Pricing**

1.2.1. The hourly pricing mechanism currently provided during on-peak periods shall also apply to semi-peak periods.

1.3. Transitional Incentive Options

1.3.1. Customers on the HPO tariff may select from two types of transitional incentive options: bill protection and technical assistance. Customers may elect to receive one of these incentives, both incentives (sequentially or simultaneously), or none.

1.3.2. Both transitional incentive options shall expire on December 31, 2005.

1.3.3. The bill protection option shall provide 100% protection (the customer pays no higher than what it would pay under its otherwise applicable rate schedule) for the customer for a maximum of 14 months.

1.3.4.1. The bill protection option shall be capped at 100 MWs.

1.3.4.2. If a customer leaves the HPO prior to the end of their 14-month commitment they shall receive no bill protection for any month.

1.3.5. The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances a customer's ability to respond to curtailment events.

1.3.5.1. Customers shall receive a rebate (not to exceed actual costs) based on no more than $50 per kW of curtailable on–peak load for technical assistance that modifies existing equipment or behavior.

1.3.5.2. Customers shall receive 50% of the rebate upon certification by a professional engineer of potential on-peak load reductions.

1.3.5.3. Customers shall receive the remainder of the rebate after demonstrating peak demand reduction equal to at least 50% of their estimated (projected by the professional engineer) load drop as averaged over four consecutive HPO months. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate.

1.3.5.4. For the purpose of measuring demand reduction, kW drop is to be estimated as the difference between a customer's specific baseline for that hour and the customer's actual energy usage during that hour. The customer-specific baseline is a 10-day rolling average energy usage determined on an hourly basis, using the average of energy usage for the three highest-use days for the same hour during the past 10 similar days.

(END OF ATTACHMENT D)

ATTACHMENT E

ATTACHMENT E
Demand Bidding Program

The DBP is an existing program recently modified by D.02-07-035. The purpose of the modified Demand Bidding Program (DBP) is to provide customers an opportunity to voluntarily bid demand reductions as a means of off-setting the utilities' procurement of energy supply when the cost of that energy exceeds a certain price. The DBP is modified in the following manner:

1.1. **Applicability :** This program is applicable to customers with demands greater than 200 kW in Pacific Gas & Electric, Southern California Edison and San Diego Gas and Electric (SDG&E) service territories.

1.1.1. Customers shall have an advanced metering system (interval meter, communication pathway, and internet-based access to usage information) as installed by AB29x, or its equivalent.

1.1.2. Customers on this tariff must agree to allow the CEC or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the program.

1.2. **Price Trigger**

1.2.1. Utility procurement departments shall forecast an hourly price offer on a day-ahead basis. This price offer is to remain confidential, which participating customers will agree to as a condition of the agreement to accept service on this tariff.

1.2.2. The DBP is triggered in those hours where the forecast price offer exceeds $0.15 per kWh for four consecutive hours between noon and 8 pm.

1.2.3. The incentive paid to participants shall be the product of the price offer and the amount of demand load reduction.

1.2.4. The demand load reduction must be greater than or equal to 50% of the bid, up to 150% of the bid.

1.2.5. Participants must commit to a minimum bid of 100 kW per hour.

1.2.6. For the purpose of measuring demand reduction, kW drop is to be estimated as the difference between a customer's specific baseline for that hour and the customer's actual energy usage during that hour. The customer-specific baseline is a 10-day rolling average energy usage determined on an hourly basis, using the average of energy usage for the three highest-use days for the same hour during the past

10 similar days (excluding other DBP days or other days the customer was otherwise paid to reduce power or the customer was subject to a rotating outage) prior to a DBP event. The three highest-use days will be determined on the basis of customer's total energy usage during the scheduled bid period for the DBP.

1.2.7. Participants will have the option to designate a pre-bid amount in which they will only be notified of a DBP event when the price trigger meets or exceeds their specified pre-bid amount.

1.5. Emergency Trigger

1.5.1. The IOUs may activate the DBP Emergency Event option, on a 'day-of' basis, when it is deemed necessary to offset outstanding system issues that may affect system reliability.

1.5.2. When a customer signs up for the program, the participant must designate a Committed Load Reduction amount that they agree to reduce their load by in the occurrence of an Emergency Trigger DBP event.

1.5.3. The incentives paid to participants during Emergency Trigger events shall be the product of their energy reduction and $0.50 per kWh.

1.5.4. The demand load reduction must be greater than or equal to 50% of the bid, up to 150% of their Committed Load Reduction.

1.5.5. Emergency Test Trigger

1.5.5.1 The utilities may activate the DBP with a simulated emergency event test trigger twice per year.

1.5.5.2 Emergency test events shall be no longer than 4 hours.

1.5.5.3 The incentive paid to participants shall be the product of their demand reduction and $0.50 per kWh per test event.

1.5.5.4 The demand load reduction must be greater than or equal to 50% of the bid, up to 150% of their Committed Load Reduction bid.

1.5.5.5 The method of measuring the demand reduction shall be the same as described in Section 1.2.6.

1.6. Transitional Incentive Option

1.6.1. Customers on the DBP may select a technical assistance incentive option.

1.6.2. This option shall expire on December 31, 2005.

1.6.3. The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances a customer's ability to respond to curtailment events. Customers shall receive a rebate (not to exceed actual costs) based on $50 per kW of curtailable on–peak load for technical assistance that modifies existing equipment or behavior.

1.6.3.1. Customers shall receive 50% of the rebate upon certification by a professional engineer of potential on-peak load reductions.

1.6.3.2. Customers shall receive the remainder of the rebate after demonstrating peak demand reduction of at least 50% of their estimated (projected by the professional engineer) load drop as averaged over all DBP events or tests. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate. A minimum of two DBP events or tests must be successfully completed.

1.6.3.3. For the purpose of measuring demand reduction, kW drop is to be estimated as the difference between a customer's specific baseline for that hour and the customer's actual energy usage during that hour. The customer-specific baseline is a 10-day rolling average energy usage determined on an hourly basis, using the average of energy usage for the three highest-use days for the same hour during the past 10 similar days (excluding other DBP days or other days the customer was otherwise paid to reduce power or the customer was subject to a rotating outage) prior to a DBP event. The three highest-use days will be determined on the basis of customer's total energy usage during the scheduled bid period for the DBP.

(END OF ATTACHMENT E)