DIRECTIONS IN DEMAND-SIDE MANAGEMENT POLICY

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ABSTRACT

Demand-side management programs should be treated on an equal footing with supply options in evaluating the desirability of future utility investments to meet customer needs. However, more accurate assessments of the energy and demand reductions resulting from utility demand-side management (DSM) programs are necessary to engender regulatory and utility confidence in some DSM programs.

Several recent developments reduce the cost-effectiveness of utility DSM programs, and imply that funding cuts are now appropriate for some California programs. Oil and gas prices have declined such that average gas and electric rates to California ratepayers are now above marginal costs, thus increasing the importance of accurate evaluation of the cost-effectiveness of DSM programs. Some programs, such as those directed toward low income and refugee customers, should be continued for equity reasons, while others which are experimental or apply to new building construction should be continued to avoid loss of opportunity.

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INTRODUCTION

Funding levels for demand-side management (DSM) programs authorized by the California Public Utilities Commission (CPUC) rose steadily from 1979 through about 1983. While evaluation techniques were quite rudimentary, particularly at the beginning of that period, the approved DSM measures appeared to be so cost-effective that the lack of rigorous analysis was little cause for concern. The primary factor limiting DSM expansion was not authorized budget levels, but the utilities' ability to develop, test, and implement the wide range of programs initiated during that time.

Beginning in late 1983, the CPUC adopted a "stay the course" funding policy for DSM[1]. Since that time, the "stay the course" policy has become increasingly more restrictive, first applied only to programs funded through base rates (with still-expanding expenditures in residential weatherization loan and rebate programs funded through balancing accounts), then extended to include all programs[2], and most recently resulting in an actual reduction of about 30 percent in the DSM budget of San Diego Gas & Electric Company (SDG&E) for 1986[3].

Ironically, the expectation that DSM programs can be relied upon and expanded to achieve significant cost savings has become less rather than more certain during recent years, even while extensive and highly sophisticated computer-based analysis tools were being developed. Several factors, quite independent of new analytical capabilities, reduce the attractiveness of DSM in California and elsewhere: the stabilization of and recent dramatic drop in oil and natural gas prices; comfortable and even excessive electric generation reserve margins in much of the country; and an approaching market saturation of some of the most cost-effective conservation measures.

Due to the decline in oil and gas prices, the utilities' marginal costs are now significantly less than their average costs for both natural gas and electricity, at least in California. This automatically creates negative non-participant impacts for all utility-funded DSM programs. As discussed in the next section, some DSM programs may still be desirable even if they increase rates to non-participants.

A less obvious, but perhaps more important outcome when marginal costs are much less than average costs is an increased pressure to keep utility rates down because of rate design problems. It becomes more difficult to design rates to recover utility revenue requirements in a manner which will prevent significant bypass of the utility system by large customers with other options for obtaining energy services, and which at the same time maintain reasonable rates to the so-called "core" customers (some of whom will also leave the system through propane, wood heaters, etc. if their rates become too high). This decreases the willingness of regulatory bodies to fund DSM programs unless they are clearly cost-effective.

One result of these changes is that utility planners and regulators can no longer afford past levels of inaccuracies in their evaluations of DSM options. DSM must now take its place as a mature technology in the utility planning process if significant expansion is to occur. However, computer analysis capabilities, while necessary, appear to have outstripped the accuracy of some of the crucial inputs. The importance of accurate measurements of DSM savings potentials cannot be overlooked, if utility planners and regulatory agencies are to avoid being trapped in a "garbage in-garbage out" mire which can cripple their ability to rely confidently on DSM to produce dependable reductions or shifts in customer demand patterns when needed.

TREATMENT OF DSM IN THE PLANNING PROCESS

It is widely accepted that DSM shold be evaluated on an equal footing with supply resources in determination of the best utility investments to meet future energy needs. However, the actual means of accomplishing this are still being debated.

As discussed extensively in the literature[4], ideal analysis techniques include linkage of demand and supply models, recognition of effects of DSM and supply expenditures on rates and the feedback effects of price elasticity on demand, rebound effects as customers use their energy-efficient appliances more or heat and cool their weatherized buildings more, and optimization routines which produce the "best" mix of supply resources and demand-side programs. The CPUC and probably most other regulatory agencies are at much more rudimentary levels in analysis capabilities.

The CPUC relies to a large extent on California's regulated utilities for such sophisticated analysis, and then performs independent evaluations of DSM programs proposed by the utilities in CPUC proceedings or in proceedings before the California Energy Commission (CEC). (The CEC has legislative authority to adopt load management standards for each utility. CPUC staff participate in CEC proceedings developing such standards, and funding is then provided by the CPUC through general rate case proceedings. In practice, only a portion of the utilities' load management programs have been covered by the CEC standards.)

CPUC staff use the production cost model ELFIN developed by the Environmental Defense Fund[5] to obtain forecasts of yearly marginal and average electricity costs of the utilities' systems operated with only built and committed resources, and then add any avoidable transmission and distribution costs and a capacity value. Comparable calculations are made to obtain marginal and average natural gas costs, to evaluate DSM programs which impact gas usage. We then assess the various resource options under consideration based on these results. In addition to DSM in the utilities' general rate cases, recent applications of this technique include determination of the value of the Diablo Canyon nuclear power plant, the long-run costs avoided by cogenerators and small power producers, and the value of a Geysers geothermal plant[6].

In most applications, the value of electric generation capacity additions or demand reductions has been assessed based on the cost of a combustion turbine, which the CPUC has adopted as a proxy for shortage costs. The CPUC staff adjusts the yearly cost of a combustion turbine by a factor reflecting need for the capacity as measured by target reserve margins adopted by the CEC in its Biennial Report process[7]. The one recent exception to this procedure has been in the proceedings to determine the long-run costs avoided by cogenerators and small power producers, in which ELFIN was used to identify new investments which could be avoided by Pacific Gas and Electric Company (PG&E) as a result of such third-party producers[8].

At this time, CPUC staff examine the cost-effectiveness of utility-proposed DSM programs based on marginal costs incurred in the absence of the programs, rather than by their inclusion in the production simulation. Cost-effectiveness is evaluated from several perspectives[9]. The two perspectives relied upon in formulating staff recommendations to the CPUC for program funding are the All Ratepayer perspective and the Non-Participant perspective.

The All Ratepayer perspective compares the present value of utility cost reductions (energy, capacity, and reliability) to the sum of utility and ratepayer costs (minus tax credits). This is the most appropriate perspective by which to evaluate DSM on an equal footing with supply resources in a "least cost" analysis.

While comparable analyses of utility supply projects do not include direct ratepayer costs, this is simply because typically there are none. For programs which incur participant costs, these costs should be recognized as an integral portion of DSM costs in cost-effectiveness evaluations. Regulatory agencies would be remiss if they were to approve large-scale DSM programs that cost ratepayers more, including non-utility costs, than other options. On the other hand, it is proper to recognize ratepayer cost reductions due to tax credits, since tax effects are also taken into account in evaluating utility investment options[10]. Thus, "least cost" analysis is properly interpreted to include all costs incurred within the utility service area (and potentially all costs incurred by society).

The Non-Participant perspective is sensitive to revenue redistributions which result from DSM programs. DSM participants typically purchase less electricity, thus reducing their contribution to the fixed costs of the utility system. Non-participants must then make up this lost revenue, and must pay a share of DSM program and incentive costs as well. These costs are compared to the benefits of DSM accruing to non-participants, which include reduced energy costs and demand-related (capacity or reliability) costs.

The Non-Participant perspective is important in assessing program design and equity impacts. However, several important caveats reduce its importance as a determining factor in DSM planning. First, all customers potentially are able to be participants in some program, making assessment of the composite equity impacts of all DSM programs more relevant than the impact of individual programs. For this reason, DSM programs aimed at reaching customers who might not otherwise participate may be desirable even if such programs do not meet the non-participant test themselves. Second, the test is very sensitive to differences between marginal and average energy and demand costs. Since each of these cost streams is difficult to predict, a large confidence interval exists around the difference between them. Finally, the Non-Participant test as presently constructed does not capture equity considerations between current and future ratepayers.

CURRENT NEED FOR RESOURCE ADDITIONS

The stabilization and recent downturn in energy costs combined with adequate and even excessive supply reduce the attractiveness of additional investments in both supply and DSM resources. CPUC staff forecasts that PG&E's electric generation reserve margins will steadily increase to reach 30 percent by 1991 and will not decline below 20 percent until 1997, even if no additional resources or DSM programs are funded beyond existing commitments[11]. The other two major regulated electric utilities in California, SDG&E and Southern California Edison Company (SCE), also appear to have more-than-adequate supplies during this period. A similar situation exists for gas utilities.

This easing of the supply situation has ramifications for the need of both proposed supply options and DSM programs. The CPUC has taken several actions in response. It has suspended the two standard contracts previously available to cogenerators and small power producers which provided some amount of pricing certainty to third-party producers until a reevaluation of their terms can be made[12]. There is significant doubt whether any long-run standard offer is appropriate at all at this time, in light of the current supply situation. The CPUC staff position is that no long-run standard contracts should be approved if there is no deferrable utility resource otherwise needed within the lead time of such a resource[13]. PG&E has also recently delayed construction of a Geysers geothermal power plant, which had been scheduled to come on-line in 1989. The delay was announced shortly after a CPUC staff filing showed that the plant is not cost-effective[14].

These examples of delay and suspension of supply resources are provided to stress that CPUC staff recommendations for caution in making utility expenditure commitments at this time are not at all limited to DSM programs. The CPUC staff maintains a strong commitment to cost-effective DSM programs. However, few programs can be shown to be cost-effective at this time.

The supply situation implies two major shifts in funding for DSM. First, longer-lived programs, whose savings extend beyond the next decade, should generally fare better than shorter-term programs in a cost-effectiveness analysis. This implies a shift, for example, from air-conditioner cycling (with meter lives of ten to fifteen years) to measures installed in new buildings which can be expected to be in place for twenty to forty years.

Second, it may be more cost-effective to delay implementation of a DSM program for several years, even if it appears cost-effective at this time. One exception would be DSM measures for new buildings, which would require expensive retrofits if done later. A capacity expansion model which optimizes resource or DSM additions should show these results; agencies or companies which do not have the benefit of an optimization model should be able to reachsimilar conclusions from multiple runs with different implementation dates for the programs under consideration.

TREATMENT OF UNCERTAINTIES IN DSM PLANNING

Resource planning must be done in the face of substantial uncertainties. Recognizing this, planners attempt to make resource decisions which will provide reliable energy supplies at reasonable cost over a wide range of outcomes. Planners should also attempt to minimize uncertainty to whatever extent possible. Thus, resources or DSM programs to which are attached significant uncertainty regarding such factors as cost, reliability, or operating dates are less desirable than those which are more dependable.

Several major sources of uncertainty are examined in this section, in an effort to identify areas of particular strength or vulnerability of DSM programs, and to pinpoint areas where additional efforts to reduce uncertainty should be made.

Sources of Uncertainty

1. Capital costs. Capital costs may be better predicted for DSM programs than for most utility-owned supply options. This is because DSM programs tend to be an aggregate of many small installations with the cost of each being fairly well known or easily verifiable through testing. Some utility supply technologies such as coal, oil or gas turbines, some hydro facilities, and transmission lines interconnecting utilities have fairly predictable costs as well. Others, with nuclear power plants and pumped hydro facilities the most notable examples in California, exhibit technological or political uncertainties which can affect capital costs dramatically. In California, there has been increasing emphasis on utility purchases from third-party power producers who take the risk of cost overruns rather than ratepayers. Some DSM rate programs (interruptible/curtailable rates, most notably) are structured similarly, so that participants bear costs of modifications needed to respond to the rates and receive bill reductions commensurate with demand reductions actually achieved.

2. Lead time. The relatively short lead time of DSM programs is one of DSM's most attractive attributes. The contribution of long and uncertain lead times to cost overruns for large utility projects is well-documented and needs only a passing mention here.

3. Value of energy and capacity replaced. This area of substantial uncertainty permeates evaluation of all investment options. The short lead times of DSM programs and the relatively shorter lives of some of them reduce the period over which these costs must be predicted and thus reduce the effect of this uncertainty on the reliability of program evaluations.

The capacity value for programs designed to reduce peak demand includes three components: generation, transmission and distribution. The generation component is modified using an adjustment factor as described above; however, the determination of the appropriate amount of avoided transmission and distribution value needs further study. Such inquiry should examine the extent of coincidence between peak system loads and peak transmission and distribution line loads, and should identify how the operating characteristics of the DSM programs affect their ability to reduce peak line loads[15].

4. Production/savings estimates. These estimates are significantly less reliable for DSM programs than for most supply options. Most conventional central station power plants operate fairly reliably once on-line (with a few obvious exceptions). Resource planning in California has been made particularly difficult, however, because of uncertainty regarding how much of the 16,000 megawatts of cogeneration and small power production which is under contract to the utilities will actually be built and provide reliable power. The CPUC has taken steps to reduce the uncertainty for future third-party projects by tightening the eligibility requirements which must be met for standard contracts. CPUC staff also recommends that there be strict megawatt limits on any standard offers which provide price certainty when they again become available to third parties.

The uncertainty of estimates of energy and demand reductions is one of the largest obstacles to reliance on DSM, and this area is one in which significant improvement appears possible. In particular, savings estimates obtained through engineering estimates and customer surveys are notoriously inaccurate. California utilities also obtain savings estimates for a number of programs from "judgment," or from energy-savings-per-dollar-spent estimates for prior years' programs. Regulatory agencies have no way to verify such estimates, and it is very difficult to determine to what extent such estimates can be relied upon. Much more emphasis should be placed on verifiable direct measurements of program savings.

Direct measurement efforts are not without potential pitfalls, however. One example is the difficult problem of accounting for a phenomenon called "selection bias" in some programs. Any DSM program which does not require verifiable changes in usage as a direct result of program operation is prone to selection bias, which can occur if there are customers who can benefit simply from signing up for a DSM program. Obviously, these customers (sometimes called "free riders") are more likely to volunteer for such a program than are those who would have to change their usage patterns to realize bill savings.

Selection bias creates a chicken-and-egg question of which came first, the desirable usage pattern or the DSM program. Measurement of program savings for those DSM programs subject to this problem simply according to usage differences between participants and the customer class as a whole is incorrect and results in an unknown overstatement of program benefits[16].

Even in such programs, selection bias can be captured and recognized in cost-effectiveness analyses by measurement of usage patterns of individual customers before and after DSM participation, in addition to comparison with carefully selected control groups. The CPUC has required California utilities to redesign and redo at least two major load management experiments because of earlier failure to measure selection bias problems—the Demand Subscription Service program of SCE and the residential time-of-use program of PG&E. Neither of the redesigned experiments is completed at this time.

There is a problem similar to self-selection inherent in many conservation programs as well, where it appears in the so-called "net to gross ratio." The measurement of net savings, as opposed to gross savings, is necessary to capture the fact that not all customers practicing conservation do so because of the existence of a utility program; that is, some people who participate in a utility program would have instituted the conservation measures even in the absence of the utility program. Therefore, the savings attributable only to the utility program must be identified and segregated. Without recognition that not all of the energy savings are due to the utility program, a program's cost-effectiveness may be significantly overstated. For this reason, estimation of net results is crucial. Net-to-gross ratios tend to be based on market surveys or, perhaps worse, on "judgment." "Judgment" should not suffice for accuracy.

Another version of this same problem also crops up in the new incentive rates recently adopted for excess natural gas and off-peak electric sales for California utilities. Such rate schedules must be targeted very carefully to sales that would otherwise not occur, since switching existing sales to a promotional rate would reduce their contribution to fixed utility costs, thus defeating the purpose of the incentive rates[17].

A final area of savings uncertainty lies in the reliability of the savings during peak demand periods. The willingness of customers to voluntarily curtail usage, for example, several days in a row during a heat storm is very difficult to measure except under those actual conditions. This uncertainty can be reduced by programs which place customers' loads under direct utility control. Even then, extensive testing and/or financial penalties for dropouts should be instituted to ensure that customers stay on the programs even under adverse conditions.

Obviously, the cost-effectiveness of DSM depends very heavily on the accuracy of the estimates of energy and demand reductions. In Figure 1, the sensitivity of the cost-effectiveness of PG&E's Direct Weatherization program to the level of realized net energy and demand savings is shown, with a range of savings estimates from one-half of that assumed by PG&E to 1.5 times the level assumed by PG&E. The benefit-cost ratio varies within this range from 0.34 to 1.01[18]. Other programs show similar sensitivities.

5. Participants' costs. This is another troublesome area which inhibits accurate evaluation of some DSM programs, with an example being load management programs which provide incentive payments in return for the ability to interrupt or curtail a customer's load for a limited number of hours per year. In cost-effectiveness analyses in California, these incentive payments have typically been treated as transfer payments from non-participants to participants, rather than as reimbursement for economic costs actually incurred by the participants. In its current rate case, PG&E assumes that there are no participant costs in its base case cost-effectiveness analysis for these programs; this assumption has been made by both the utility and CPUC staff in prior cases.

It appears unreasonable to assume that customers, particularly commercial and industrial customers, do not incur costs by participating in load management programs, since they are asked on short notice to drop either all or some portion of their loads and this disrupts the normal course of business. Such disruptions may cause less economic costs to residential customers since their costs are generally minor inconveniences and discomfort that do not have a pocketbook impact. Nevertheless, from a societal perspective, such minor inconveniences have value, as is exhibited from the drop-out rates experienced in such programs, and should be recognized.

It is probably reasonable to assume that customers' costs do not exceed the level of the incentive payment and that, absent better information, customer costs thus lie somewhere between zero and the level of incentive payments.

Figure 2 illustrates the sensitivity of cost-effectiveness of one load management program to the level of participant costs. The program shown is PG&E's Group Load Curtailment program, and the analysis is taken from CPUC staff's report in the current rate case[19]. Two cases are shown: one which values capacity savings at the full cost of a combustion turbine and one which reflects reduced capacity value due to the high reserve margins expected for PG&E during the next decade. The effect of participants' costs overwhelms the impact of reserve margin on cost-effectiveness, with the benefit-cost ratio using staff's reserve margin adjustments declining from 3.5 to 0.6 as participant costs vary between zero and the level of incentive payments proposed by PG&E.

Some load management programs can be designed to circumvent the lack of knowledge regarding participants' costs by setting the incentives at a level which would reflect the value of the savings to the utility (minus any program costs). This would constrain the benefit-cost ratio from the All Ratepayer perspective to be above or close to 1.0, even if participant costs equal the full incentive payment. Note, however, that this is true only for programs which have no selection bias problems.

Planning in the Face of Uncertainty

Several actions can be taken to reduce the impacts of uncertain future events on the cost and reliability of utility services. In California, at least, the task is made significantly easier by the apparent overcapacity situation before us. Besides showing caution in authorizing utility commitments to new supply investments or purchase contracts, regulatory agencies in similar situations can follow several general policies regarding DSM programs:

1. Experiments should be continued to determine DSM program designs which are now or which can become cost-effective. Pilot programs designed to evaluate customer responses to DSM programs can be useful.

2. Measurement techniques should be refined, so that savings estimates of DSM programs can be more reliable than they are presently. Customized market research surveys and conditional demand analyses are effective techniques for determining net participation and gross savings, respectively.

3. Because of the vigorous support for DSM in California in prior years, funding cuts are now appropriate; however, funding should be sustained at levels sufficient to maintain the utilities' internal structure for those DSM programs which show promise but which are not currently cost-effective, so that rapid expansion can occur if these programs become cost-effective in the future.

4. Incentive payments for load management programs should not necessarily be reduced to the point of cost-effectiveness in light of oversupply situations. Current customer participation should be maintained to keep existing programs operational if they show promise of becoming cost-effective in the future. However, programs with incentive payments in excess of their current value should be closed to additional participants unless needed for experimental purposes. The utilities should not actively recruit new participants in cases where availability is maintained for other reasons.

5. Marketing-type activities to encourage increased usage should be entered into very cautiously, with careful targeting to ensure that existing sales are not shifted to incentive schedules and with measurements made of the effectiveness of the programs.

6. Some DSM programs should be funded for hard-to-reach customers, such as low-income and refugee groups, for equity reasons.

7. Careful sensitivity analyses should be done to assess the change in cost-effectiveness of programs due to unpredictable or unmeasurable factors, such as fuel price, energy and capacity savings, participant costs, reduced air pollution and reduced oil imports. Emphasis should be placed on those programs for which cost-effectiveness is more assured, i.e., less sensitive to such factors.

8. Studies need to be performed to identify participant costs for DSM programs.

CONCLUSION

At this time, significant uncertainties, in particular regarding the energy and demand savings of some DSM programs, limit the degree of reliance utility planners and regulators can place on such programs. However, in California at least, the "window" of the next few years when there are no pressing needs for new resource investments provides time which should be used to continue experimentation and to refine analysis techniques and measurement methods for DSM programs, so that they can take their place as mature technologies to be evaluated on an equal basis with supply options.

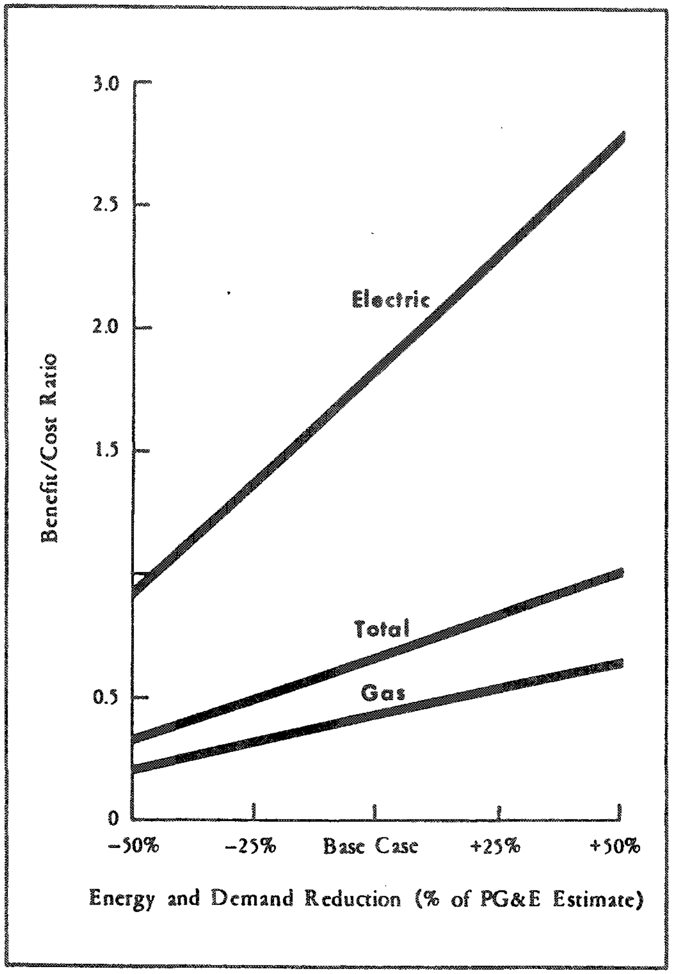

Figure 1. Sensitivity of cost-effectiveness of PG&E's Direct Weatherization program to estimate of energy and demand reductions (All Ratepayer Perspective).

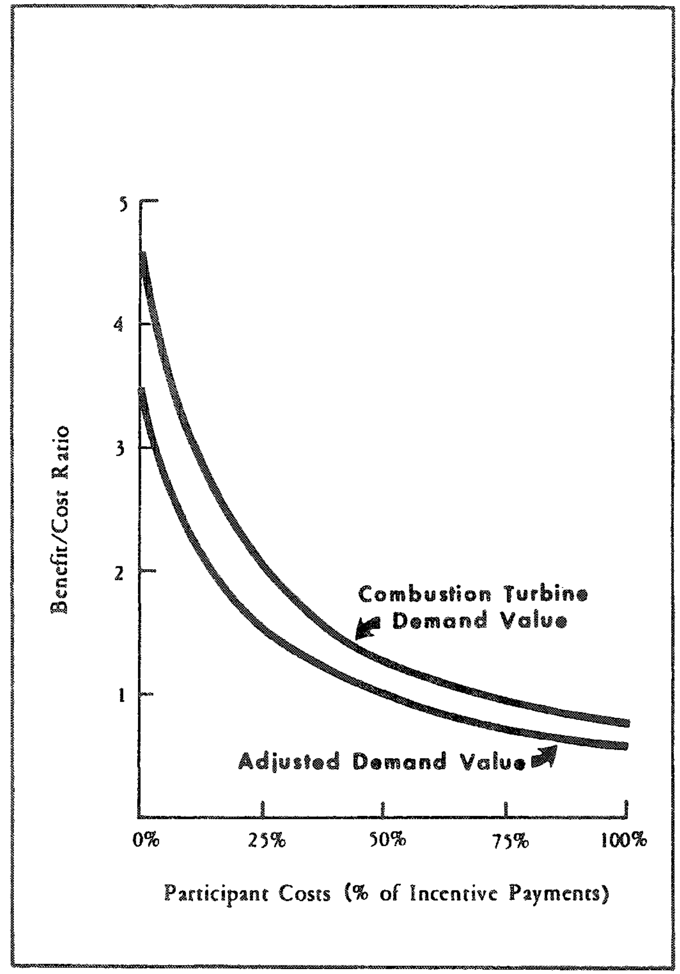

Figure 2. Sensitivity of cost-effectiveness of PG&E's Group Load Curtailment program to estimate of participant costs (All Ratepayer Perspective).

NOTES

1. CPUC Decision (D.) 83-12-068 in Application (A.) 82-12-048, PG&E's 1984 general rate case.

2. A) CPUC D.84-12-053 in A.83-12-053, SCE's 1985 general rate case.

   B) CPUC D.84-12-069 in A.84-02-025, SoCal Gas's 1985 general rate case.

3. CPUC D.85-12-108 in A.84-12-015, SDG&E's 1986 general rate case.

4. One example: Andrew Ford and Jay Geinzer, "The BPA Conservation Policy Analysis Models," University of Southern California and Applied Energy Services, March 1986.

5. "ELFIN Users Manual," Environmental Defense Fund, Berkeley, California.

6. A) "Diablo Canyon Nuclear Plant Value-Based Pricing Proposal" in A.84-06-014, CPUC Public Staff Division, San Francisco, California, November 4, 1985.

   B) "Prepared Testimony of the Public Staff Division, Phase II of the Proceeding to Develop a Long-Run Standard Offer for Cogenerators and Small Power Producers" in A.82-04-044, et al., January 6, 1986.

   C) "Comments of the Public Staff Division on Trended Rate Base Required by Decision No. 86-03-088, and Motion to Re-open the Proceeding to Determine the Cost-effectiveness of Unit 21," A.84-07-026, April 21, 1986.

7. A) See Note 6B.

   B) "The 1985 California Electricity Report: Affordable Electricity in an Uncertain World" and Appendices, California Energy Commission, Sacramento, California, May 1985.

   C) "Report on Marginal Cost, Revenue Allocation and Rate Design for Pacific Gas and Electric Company" in A.85-12-050, PG&E's 1987 general rate case, Energy Rate Design and Economics Branch, CPUC Public Staff Division, March 1986.

   D) CPUC decisions on the proper adjustment mechanism are pending. The staff-proposed adjustment factor is 1.0 during years in which the forecasted reserve margin is less than the CEC target reserve margin (except in the short run when it can increase to 2.0 if the utility does not have time to construct a gas turbine or other supply resources to meet immediate capacity shortfalls); 0.0 when the forecasted reserve margin is greater than the target reserve margin plus ten percent; and a linear factor between 1.0 and 0.0 when reserve margins are between these two extremes.

8. A) See note 6B.

   B) In that application, both energy and capacity payments to the independent producers would be based on the avoided investment rather than on short-run marginal operating costs and a combustion turbine.

9. "Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs," Joint Staff Report of CPUC and CEC, February 1983, and Update.

10. An argument can be made for using a societal perspective in which tax credits are treated as transfer payments. Whichever perspective is chosen, it is most important that there be consistency in treatment of tax credits in evaluating both supply and DSM options.

11. "Demand-Side Management, Pacific Gas and Electric Company" in A.85-12-050, PG&E's 1987 general rate case, Energy Resources Branch, CPUC Public Staff Division, April 1986.

12. The CPUC has approved four "standard offers" which were to be available to any cogenerator or small power producer which met certain eligibility criteria, at that party's sole option. Cogenerators and small power producers can also negotiate non-standard contracts with the utilities if they wish to do so. The two currently suspended included a short-run offer with fixed levelized capacity payments and a long-run offer based on deferral of future utility investments. A CPUC decision on the long-run offer is expected in June 1986.

13. See Note 6B.

14. See Note 6C.

15. A) Certain interruptible programs are triggered automatically by a drop in transmission line frequency and are thus able to alleviate the loading on the lines. This is an example of DSM programs which should receive full transmission value.

    B) The cost of avoided capacity (assuming full value for the three components and expressed in 1987 dollars) for PG&E is about \$159.43/kW, including \$67.50/kW for generation, \$12.95/kW for transmission and \$78.98/kW for distribution (see Note 7C).

16. This discussion begs the question of whether customers with preexisting off-peak usage patterns <u>should</u> receive lower utility bills, commensurate with the lower costs imposed on the utility system. Programs with that primary aim are perhaps more correctly classified as "rate options" rather than load management, whose aim is to change customer usage patterns in a cost-effective manner.

17. This discussion does not touch on a number of other issues attached to incentive rates, e.g., the wisdom of embedding increased usage habits during the current supply surplus, and whether a particular rate design encourages non-economic (from a societal perspective) or inefficient use of energy.

18. These calculations are based on CPUC assumptions as contained in Note 11; results shown are from the All Ratepayer perspective.

19. See Note 11.