REPORT SUMMARY

SUBJECTS	Demand-side planning / Distribution: Substations / Conservation/productivity/load management
TOPICS	Demand-side planning Load management Conservation Distribution substations Load control Forecasting
AUDIENCE	Demand-side planners / Distribution engineers

Utility Benefits From Targeting Demand-Side Management Programs at Specific Distribution Areas

Targeting demand-side management (DSM) programs to specific locales that are experiencing demand growth within a utility service area may delay or eliminate some capital expenditures. This case study of three substation areas also indicates that certain locales show greater potential savings from DSM programs than others.

BACKGROUND The cost of meeting electricity requirements can vary from one geographic locale to another within a utility service territory. But conservation and load management efforts are usually addressed uniformly on the basis of total utility system savings. Costs and benefits of load deferral on particular distribution substations have not yet been considered.

OBJECTIVE To examine the potential savings from deferred investments in distribution substations as a result of targeting DSM programs to locales with impending need for increased substation capacity.

APPROACH A major factor in locale-specific costs is the capital expenditure for modifying distribution substations to meet demand growth. Thus this study examined three Pacific Gas and Electric Company substations with high utilization factors. Using a simple analytic model, the project team assessed the feasibility and benefits of targeting conservation or load management programs toward customers in the service areas of these substations.

RESULTS The study concluded that certain substation service areas show greater potential savings from conservation and load management than others. And, although the overall potential benefits of targeting are likely to be small compared to total distribution expenditures, the benefits may be substantial when compared to the relative effort required. Annual savings of several million dollars could possibly be achieved in a large utility if demand growth could be managed geographically.

For the three cases examined, one substation service area was found to be considerably more attractive than the average because of impending capital expansion. Consequently, project analysts identified this station as one where targeted DSM programs could be quite cost-effective. Results from the second substation area indicated that feeder transfer and existing conservation programs would serve to defer transformer capacity additions in the near future. The third substation area exhibited uncertain growth and alternative investment options but appeared to warrant closer examination.

EPRI PERSPECTIVE The issues related to distribution system impact of utility DSM programs have not been specifically addressed in prior research. This project concludes that targeting DSM programs at specific distribution areas may lead to the deferral of investments for substation reinforcement. This work outlines a simple approach for identifying such substations and applies this approach to a case study utility, demonstrating the potential benefit. Related EPRI-sponsored research continues under projects RP2548 and RP1979.

PROJECT RP2152-1
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Utility Benefits From Targeting Demand-Side Management Programs at Specific Distribution Areas

EM-4771
Research Project 2152-1

Final Report, August 1986

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ABSTRACT

The total cost of satisfying electricity needs can vary from locale to locale within a utility's service area. Therefore, it may be possible to utilize geographically targeted programs for demand management to reduce utility costs. This study identifies and analyzes factors influencing locale-specific cost differentials. One of the most important factors is the capital expenditures for occasional reinforcement of distribution substations. This study examines selective targeting of conservation and/or load management programs to areas served by distribution substations needing such reinforcement, so that capital expenditures can be deferred or eliminated. The study also addresses potential regulatory constraints and related costs. Study results indicate that a targeted demand-side management effort may be effective, providing benefits to the ratepayers and the utility.

ACKNOWLEDGMENT

We gratefully acknowledge the assistance of the Pacific Gas and Electric Company in supplying data on which to base specific examples. Corporate headquarters personnel in distribution planning and conservation planning, and the conservation personnel of the San Jose Division were extremely helpful with both advice and information.

This report was prepared by R&C Enterprises, Ltd. with subcontract work done by Future Resources Associates, Inc. The R&C Enterprises, Ltd. project personnel were Bruce Rosenblum, Paul Donovan, Hans Hamester, Carlo LaPorta, and James Taul. The Future Resources Associates, Inc. project personnel were Robert Budnitz, Edward Kahn, and Joseph Eto.

We also acknowledge the efforts of Eileen Watts of Synergic Resources Corporation in editing this report.

CONTENTS

SUMMARY

The cost of meeting electricity requirements can vary from one geographical locale to another within a utility service territory. Utility conservation and load management efforts are usually addressed uniformly to the entire territory. Significant benefits to the utility may accrue by geographically targeting conservation and load management efforts to emphasize those locales in which the cost of meeting demand or demand growth is high.

A major factor in locale-specific costs is the capital expenditure needed occasionally to reinforce distribution substations to meet demand growth. By targeting conservation and load management programs to locales with impending need for substation reinforcement, these expenditures might be delayed or obviated.

A simple model indicates that annual savings of several million dollars can be achieved in a typically sized and growing utility if demand growth could be managed geographically. An examination of the distribution planning and conservation potential in a number of actual locales indicates that expenditure deferrals of a few million dollars for a few years are possible for certain "not untypical" proposed substation reinforcements.

An examination of several existing and successful demand-side management (DSM) programs to assess their potential for targeting indicates that a significant amount of geographical emphasis could be achieved by minor changes in implementation methods. A review of regulatory and other constraints concludes that there would be no serious impediments from these sources.

In order to target conservation and load management programs to locales where costly substation reinforcement is impending, interaction and cooperation between distribution planners and DSM planners are needed. The interaction mechanism, however, can be quite straightforward and cause little disruption; in fact, it may have positive effects on the functioning of both groups.

The most appropriate approach to gepgraphical targeting will vary from one utility to another. Such efforts, however, can be introduced and tested in a single program, in a single locale, and with any chosen degree of geographical emphasis. Geographically-targeted DSM programs can be developed gradually as the utility gains experience in the implementation of such programs.

Section 1

INTRODUCTION

Today's pursuit of the efficient use of electrical energy through demand-side management (DSM) is not only a societal goal; it often proves beneficial to utilities. This study investigates additional possible advantages and potential problems involved in targeting such efforts toward specific geographical locales within the utility service area to the utility's greatest benefit. In most current DSM planning, important locale-specific considerations are largely ignored.

As an illustration of a possible benefit of geographical targeting, consider a situation where a projected increase in peak demand in a locale would require an immediate and costly reinforcement of distribution facilities. Concentrating conservation or load management efforts to reduce demand growth in that particular locale might well delay or even avoid significant capital expenditures.

The major implications of demand-side management are changes in fuel and new plant construction costs. Since growth rates, however, tend to vary radically across relatively small areas in a utility service territory, even small modifications of such growth, if well-directed geographically, might enhance efficiency in the use of scarce capital. The small geographical scale involved here causes this study to be directed toward the distribution component of the generation/transmission/distribution triad.

This analysis of factors affecting the costs of meeting locale-specific demand concludes that the major avoidable costs involve postponements in the reinforcement of substations. In the absence of published data and analytical methods relevant to evaluating these potential savings, a model is developed to calculate an upper limit for the deferred or avoided capital expenditures possible with an ideally efficient demand growth control. It is found that annual savings of several million dollars are possible for a "not untypical" utility.

To assess the feasibility of identifying locales that warrant the targeting of conservation and load management activities and the benefits and problems of accomplishing this targeting, actual distribution systems with two very different sizes are considered. The first is the set of thirteen operating divisions of the Pacific Gas and Electric Company; the second is a set of three much smaller locales within those divisions, each serviced by several substations. It appears possible to identify locales--at both levels of aggregation--in which the reduction of peak demands would be particularly advantageous for the utility.

The practicality of geographically targeting DSM efforts, such as conservation and load management projects, to achieve locale-specific peak demand reduction may be influenced by the constraints imposed by legal and regulatory agencies, as well as public and political perceptions. These external constraints are usually not different from those for non-targeted DSM programs and appear to present no problems. Public and political concerns over possible equity issues have lessened with respect to individual programs, when the programs, *in toto*, are perceived as equitable. Moreover, the geographical targeting discussed here is beneficial at almost no additional cost to any ratepayer.

In addition to external constraints, there may be internal barriers, because the utility itself resists change for too small an advantage. A geographical targeting program will necessarily require new interactions between distribution planners and DSM implementation personnel, as well as management initiatives at a higher level. This study suggests that any disruption may be minimal, and that other benefits could result in addition to reduction in capital expenditures. These interactions and the resulting targeting will give added flexibility to distribution planners by allowing them to exert some control over locale-specific demand growth. Conservation and load management planners will welcome the new role of providing corporate benefit through obvious and specific examples of capital expenditure deferral.

The examination of several successful conservation and load management programs indicates that the application of geographical targeting criteria to program participant selection may be feasible with little additional effort. In fact, some of these programs are presently *de facto* targeted geographically, but without regard to the requirements of distribution planning. A simple mechanism to incorporate such distribution-based geographical criteria is outlined in this report.

Can geographical targeting adversely affect the goals of conservation and load management programs in achieving desired systemwide impact? To answer this question, each situation must be analyzed individually. This study presents a framework to analyze program response proximity to saturation. For most programs, targeting will not present problems on this score, and in some cases targeting may even contribute to reaching systemwide goals.

Geographical targeting is a technique whose best application will vary greatly with the characteristics of a utility's service area, corporate organization, and the nature of its existing DSM programs. Furthermore, targeting can be introduced in a single program, in a single locale, and to an almost arbitrarily small degree. Such trial introduction of targeting on a small scale and the attendant effort, to fine tune it as implementation experience grows, may eventually lead to an optimum targeting program. This report outlines an approach for targeting DSM programs, and for collecting and analyzing information on resulting benefits.

Section 2

SCOPE OF STUDY

The general project goal is a preliminary assessment of the practicality of, benefits of, and methods for, targeting DSM programs such as conservation, load management, and alternative energy projects to specific customers.

Practicality: Focus is on activities presently within the regulatory options available to utilities. Programs currently within utilities' organizational capabilities are emphasized, and activities that could become feasible in the future are mentioned.

Benefits: Benefits are assessed for the utility, specific customers, ratepayers, and society as a whole. The study identifies certain equity issues relative to the distribution of benefits and costs.

Methods: The methods for targeting are narrowed to selective advertising and individual contact with selected customers. There is little analysis of special inducements to selected customers within a customer class. Specific (dis)advantages of such special inducements are discussed.

DSM Programs: The focus is on conservation and load management. The results may be generalized for other types of DSM programs.

Specific Customers: The specific customers are those for whom a reduction of electricity use, a change in time or pattern of use, or a reduction or postponement of intended use would benefit the utility. Emphasis is on customers who can be targeted efficiently.

Section 3

THE POTENTIAL BENEFIT OF LOCALLY CONTROLLING DEMAND GROWTH

This section addresses the potential benefits of controlling demand growth in specific locales by geographically targeting conservation and load management programs. In order to focus the analysis on the effects of targeting, it will be assumed that systemwide demand will be unchanged (relative to the case with no targeting), and that targeting will have no effect on generation costs. The analysis proceeds along two axes: from theoretical to actual practice, and from micro to macro perspectives.

The first topic treated in this section concerns factors affecting demand growth in specific locales. The discussion then focuses on substation reinforcement, followed by a simple mathematical/graphical model which facilitates analysis of different utility situations. In particular, the model compares an actual utility situation to an "ideal" one with respect to possible benefits of targeting demand-management programs.

There is no patent solution to choosing the appropriate size of locales for targeting conservation and load management programs. Each situation must be studied to determine the optimum benefit. To demonstrate the existence and range of such benefits, the study examines two extreme cases for a particular utility, the Pacific Gas & Electric Company (PGandE). First, the thirteen large operating divisions are investigated. Then, within particular divisions, three much smaller areas are analyzed on almost a substation-by-substation basis.

FACTORS AFFECTING THE COSTS OF MEETING ELECTRICITY DEMAND IN SPECIFIC LOCALES

Economic, demographic and geographic factors affect the cost of delivering electric power across locales. Essentially, variations in local land use patterns and the superimposed network of electric utility transmission and distribution equipment determine the locale-specific cost of power delivery. These locale-specific variations are not explicitly addressed in rate-making. They become important, however, when conservation and load management programs are considered. These programs can produce greater benefits in locales where there is significant potential to avoid costs. In other locales where the cost of service is lower, or no substantial costs are avoidable, such activities would be correspondingly less productive.

This section will identify elements influencing principal local variataions in electric power costs. These consist of customer class distribution and a range of cost factors, including those that are avoidable through demand-side management programs and those that are not.

Customer Class Distribution

The cost of increased service to a locale can vary with the customer class distribution in the locale, and the need for increased service to specific classes. Rates paid by different customer classes usually take this cost difference into account. Consequently, demand-side management programs targeted at particular customer classes will not achieve this study's objective. Hence, although the cost of increased service requirements in a locale will certainly depend on the customer classes which predominate in it, this aspect of customer class distribution is treated implicitly by its effect on other factors to be discussed. Of course, the dominant customer classes in a locale will influence the choice of targeting mechanisms addressed to it, and will be considered in Section 4.

Analysis of Cost Factors

Numerous interrelated factors determine the costs of delivering electric power to customers. The degree to which these factors are affected by targeting conservation and load management programs is examined, indicating that the primary focus should be on costs of new or reinforced substations.

Variable vs. Fixed Costs. The principal transmission and distribution costs that vary with power consumption are line losses (I^2R). These losses, in turn, are related to the voltage at which customers take service (lower losses for high voltage use) and the length of feeder lines. Only voltage differences are explicitly accounted for in rate-making. Customer class loss rates vary by a factor of two or more. For example, PGandE reports demand losses of 10.6% at the secondary level, but only 5.3% at the transmission level (1).

For a given increase in demand, some locales show a significantly greater increase in line losses when compared to the average locale. Such losses, however, increase gradually with demand growth. Therefore, the associated cost is more tolerable than, say, a capital expense suddenly necessitated by a relatively small increase in demand. Furthermore, the general move towards higher primary feeder voltages tends to reduce these losses and, in special cases, reconductoring is possible, often at minimal expense.*

The other main variable costs in transmission and distribution involve operation and maintenance. PGandE estimates these at $28.7 million and $186.5 million respectively for 1982 (1). Spread over a 1981 sales base of 61.7 billion kWh, this amounts to 3.5 mills/kWh. The extent to which these costs are avoidable is not known. But because most of these are fixed, they do not change rapidly with a change in demand.

All other costs of the transmission and distribution system are fixed. Among them are embedded costs, not subject to change in the short run, and marginal costs, which could be avoided through conservation and load management.

Embedded v. Marginal Costs. Transmission and distribution costs are capital intensive. On a marginal cost basis, the previously cited operation and maintenance costs comprise only about 13% of marginal transmission costs and 8.5% of marginal distribution costs (1). Consequently, the potential for avoiding these capital costs, whether embedded or marginal, is an important aspect of locally controlling demand.

Regarding the embedded or sunk costs of equipment assignable to a specific locale, this study will focus on cash expenditures necessitated by demand increases. Since removal of equipment from a locale is rarely warranted, these costs are usually not recoverable. Furthermore, the bookkeeping treatment of sunk costs is dominated by various conventions. Minimizing these costs does not appear to be a meaningful goal for targeted demand-management programs.

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*Although line losses may warrant consideration in some special situations, we will address them as a distinct item only briefly. In ignoring line losses we recognize that this also implies ignoring the relative locations of generating plants.

More importantly, embedded costs are generally much smaller than marginal costs, if only because of inflation. Data published by California utilities indicate that the marginal cost of distribution is three times that of the corresponding embedded cost. For example, Southern California Edison Company (SCE) estimated that the marginal cost of distribution demand is $314/kW in 1983 dollars (2). The original cost of the SCE distribution system as of 1981 was about $2.19 billion. Net of accumulated depreciation and salvage value, the SCE rate base for distribution is about $1.76 billion (2). Assuming that the ratio of SCE distribution demand to generation peak demand is the same as that for PGandE, then the 1981 SCE distribution peak was approximately 17,600 MW. This implies a current average (or embedded) cost of about $100/kW.

The marginal cost estimates cited are made on a statistical basis at a high level of aggregation. They include many items that are customer-specific or do not necessarily scale very strongly with the size of customer loads. Therefore, not all of these costs may be avoidable by targeted DSM efforts.

Unavoidable v. Avoidable Marginal Costs. The marginal cost of electricity distribution encompasses such a variety of costs that some clarifying terminological distinctions are needed to distinguish those which are avoidable by targeted DSM efforts. The marginal or incremental nature of a cost element does not imply avoidability. For example, not all distribution reinforcement plans are driven strictly by load growth considerations.

Transmission costs are unavoidable because of the multi-purpose nature of capacity additions. Transmission capacity may be added to serve incremental generation, to balance power deliveries, to maintain system stability, or to serve growing local loads. It is extremely difficult to identify the load-related element of transmission investments in general. In particular cases, however, transmission or sub-transmission investments are made to a distribution substation whose capacity is also increasing. Here, the linkage between capacity addition and load is explicit. In this case, avoiding or deferring transmission investment is possible if effective locale-specific demand management programs are feasible.

The avoided cost, however, is likely to be small for transmission lines because of the small fraction of total cost directly related to capacity. In addition, the dominant cost factors for transmission (towers and real estate costs) are fixed.

Finally, the practicality of avoiding or deferring capacity may be questionable. A two-year delay in 30% of a line's capacity may not be economic if there is a scale economy in the installation. It may be less expensive to install capacity in advance of the load than to incur the extra labor cost involved in returning later and adding capacity. The key elements of this decision are the relative magnitudes of equipment and labor costs.

The remaining candidates for avoidable marginal costs are conventionally referred to as distribution costs.

Cost of Extending Primary Feeder Lines and Distribution Transformers. Primary feeders and associated equipment are the major costs in distribution, and are substantially unavoidable in supplying service to new customers, or for new uses by existing customers.

The resulting addition of primary feeders and associated equipment, however, is a continous function of demand and is consequently less significant, analogous to the case of line losses. The time-scale for the planning of primary feeder lines is also typically shorter than the year or more needed for a targeted demand growth management program to take effect.

Finally, the cost of the new feeders, etc. is determined within the small locale serviced by the feeders. To remove the necessity for such reinforcement, conservation and load management programs would have to be directed to that same very small locale (relative to the area served by a substation set). Rarely will this be an area of a size warranting targeting.

Therefore, saving these types of costs is not usually an appropriate reason to institute locale-specific demand-side management.

Cost of New or Reinforced Distribution Substations. The distribution substation aggregates individual loads and connects them to the bulk power system. This connection requires transforming voltage from economically desirable levels for transmission to levels that are economic for delivery. A targeted demand-side management program that reduces the load of many customers in a locale results in reduced demand for transformer capacity at the substation. This reduced demand translates, in turn, into avoidable expenditures for sub-transmission feeders, substation transformers, interconnects, and, if a new substation is involved, real estate.

While other elements of the distribution system involve potential avoidable costs, their magnitude is not large in comparison with avoided substation costs. For example, line or distribution transformer capacity can be reduced by demand management activities. These transformers exhibit scale economies, and costs range from $6-13/kVA. These are substantially less than the average $55/kVA cost of substation transformers alone (3). Similarly, savings can result from optimizing the size of distribution conductors with respect to reduced loads. A case study of such optimization, though, found only a 7% reduction in total cost from controlling conductor size (4).

However, substation expenditures can be required quite discontinuously. Forecasted demand growth in some locales can require substantial additions, while the projected growth for other areas is small or could be accomodated with existing substation facilities. Typically, demand growth can be accommodated in an area for a considerable time with no additional substation expenditure, but then at some point a quantum jump in the addition of capacity at a cost of, perhaps, a million dollars, or even much more, is required. The need for such a steep increase in capacity is usually predictable several years in advance. If the growth in demand in the locale with nearly saturated substation capacity could be slowed or avoided by conservation and load management programs, the expenditures could be postponed or possibly avoided. The geographical scale of the area serviced by a substation, or by a group of interconnected substations, is likely to be large enough to warrant such a targeted program, but not so large that the electrical and economic/demographic situation is excessively diverse.

Note too, that insofar as substation costs can be reduced or deferred by targeting, the benefits arise from peak reduction, rather than from saving kilowatt-hours. Distribution capacity is needed to meet the peaks; the average here is less important. The cost differential of peak vs. baseload generation and transmission also enhances this benfit of conservation and load management.

Finally, localized management of electrical demands may increase reliability by responding rapidly to locale-specific impending or actual transformer overloads. That is, the reliability benefits associated with any demand management effort at the generation level increase as those efforts address mismatches at greater levels of disaggregation, down to the substation level. We do not, however, attempt to quantify these benefits.

Conclusion

In view of the above considerations, this study will focus on targeting conservation and load management programs as part of a demand-side management plan to avoid or delay expenditures for substation additions or reinforcements. While not the sole source of benefits, our analysis indicates that it is the most significant case to analyze in order to demonstrate that such targeting can produce substantial benefits.

A TECHNIQUE FOR VISUALIZING THE EFFECT OF TARGETED DEMAND MANAGEMENT PROGRAMS

The last sub-section outlined the reasons for our study's focus on targeting (certain) conservation and load management programs toward locales where new or reinforced substations are likely to be needed. Clearly, the benefits to a utility depend on the programs' effectiveness. This section addresses the upper limit benefit by comparing the difference between the rates of capital expenditures in two hypothetical utility situations.

The technique or model we employ provides a convenient visualization of the targeting process. In a more realistic and necessarily complex scenario, the same model provides a tool for more detailed study and planning of targeted DSM programs. In actual targeting situations, many locale-specific factors not considered here would come into play.

We define two terms as follows:

> "Adjusted utilization factor" (AUF) is the peak load* for a particular distribution unit (substation or set of interconnected substations) divided by the "adjusted capacity" of the unit.
>
> "Adjusted capacity" of a distribution unit differs from "nameplate capacity" in that factors such as the cooling situation and possible emergency needs are taken into account so that the "adjusted utilization factor," is unity for the most efficient equipment use.

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*By "peak load" we refer to the effective peak load averaged over appropriate times to account for thermal capacities of transformers, etc.

The histogram of Figure 1 represents a "not untypical" utility situation. The variously hatched sections of the bars for each AUF range represent separate substations (or sets of interconnected substations, each appropriate for treatment as a unit). An actual utility may have substantially more such units.

The arrows on each hatched unit indicate the fractional annual growth in peak demand projected for the locale served by the substation set. An arrow to the left indicates a decrease in peak demand projected for that locale. The average growth for the utility pictured is 3.8 percent per annum.* The growth projection arrows in Figure 1 may well include the effect of service-area-wide DSM programs.

For illustrative purposes, assume that an effective locale-specific demand management program strongly reduced the growth (motion to higher AUF) for all locales with 0.95 AUF 1.0. If the total effort for the service area remained constant, one can assume that the total (peak) load growth for the area would remain constant. (This assumption is discussed in detail in Section 4.) The relative growth in the untargeted areas would therefore increase. The slower motion to higher AUF for those locales with AUF 0.95 and the more rapid motion to a higher AUF for those with smaller AUFs would skew the histogram to the right over several years, as shown in a fairly extreme example with crosshatch lines in Figure 2. The original form of the histogram (Situation 1) is shown superimposed with horizontal lines in this figure. As mentioned above, the form of this histogram may remain constant over time if there is no effort to change it by, say, targeted conservation or load management programs.

The two histograms of Figure 2 could represent two unchanging utility situations. They may also represent alternative possible futures for the same utility. The one drawn in bold (Situation 2) represents a future brought about by locale-specific demand-management efforts. In both situations the total delivered peak power and the rate of increase of delivered peak power are the same, since the targeting need not have changed either of these.

The key question, then, is: what is the difference in the rate of capital expenditure for the reinforcement of substations in the two situations?

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*This figure is an average of EPRI's low and intermediate growth projections through the year 2000 (5).

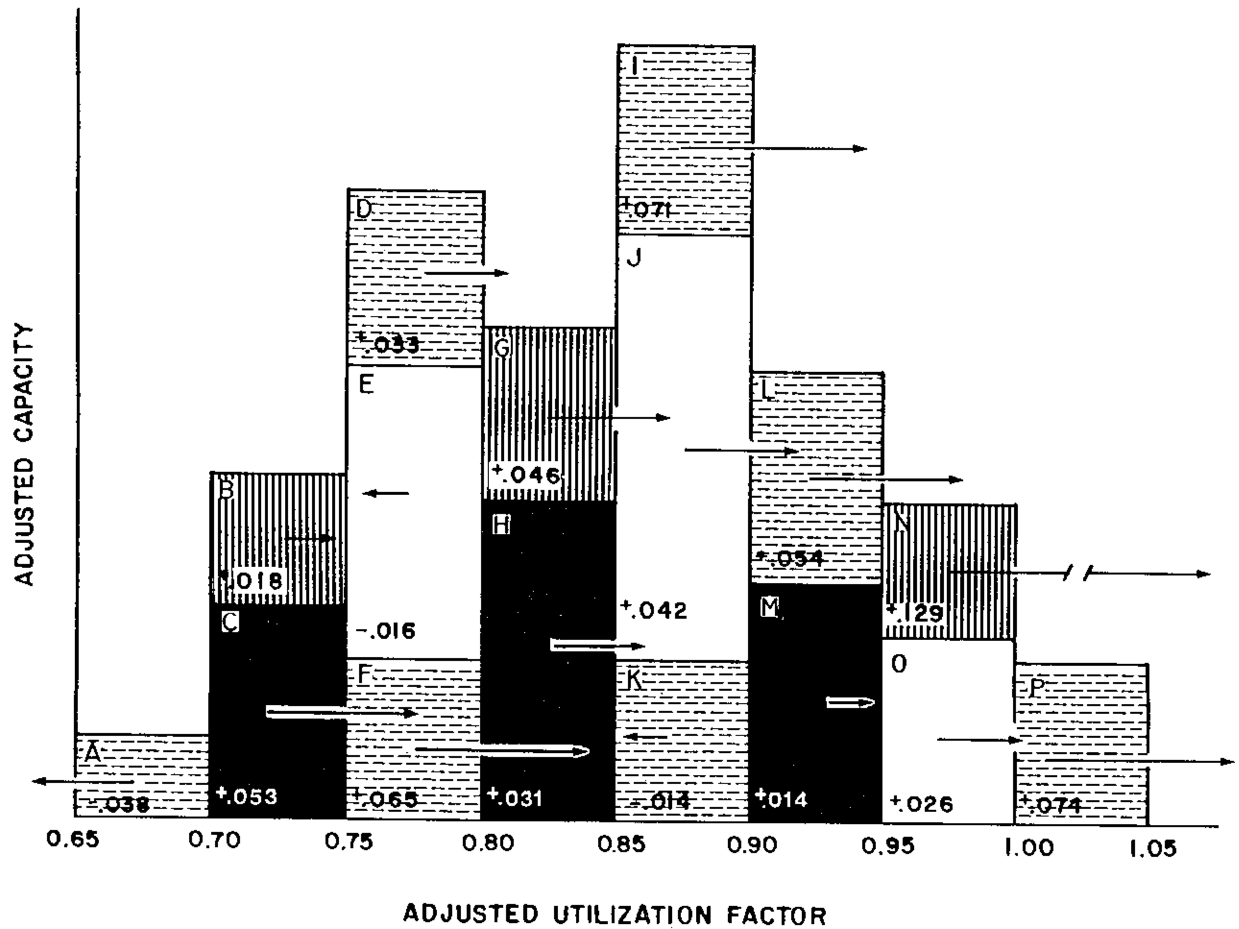

Figure 1. Substation Capacity at Various Utilization Factors for a Not Untypical Situation

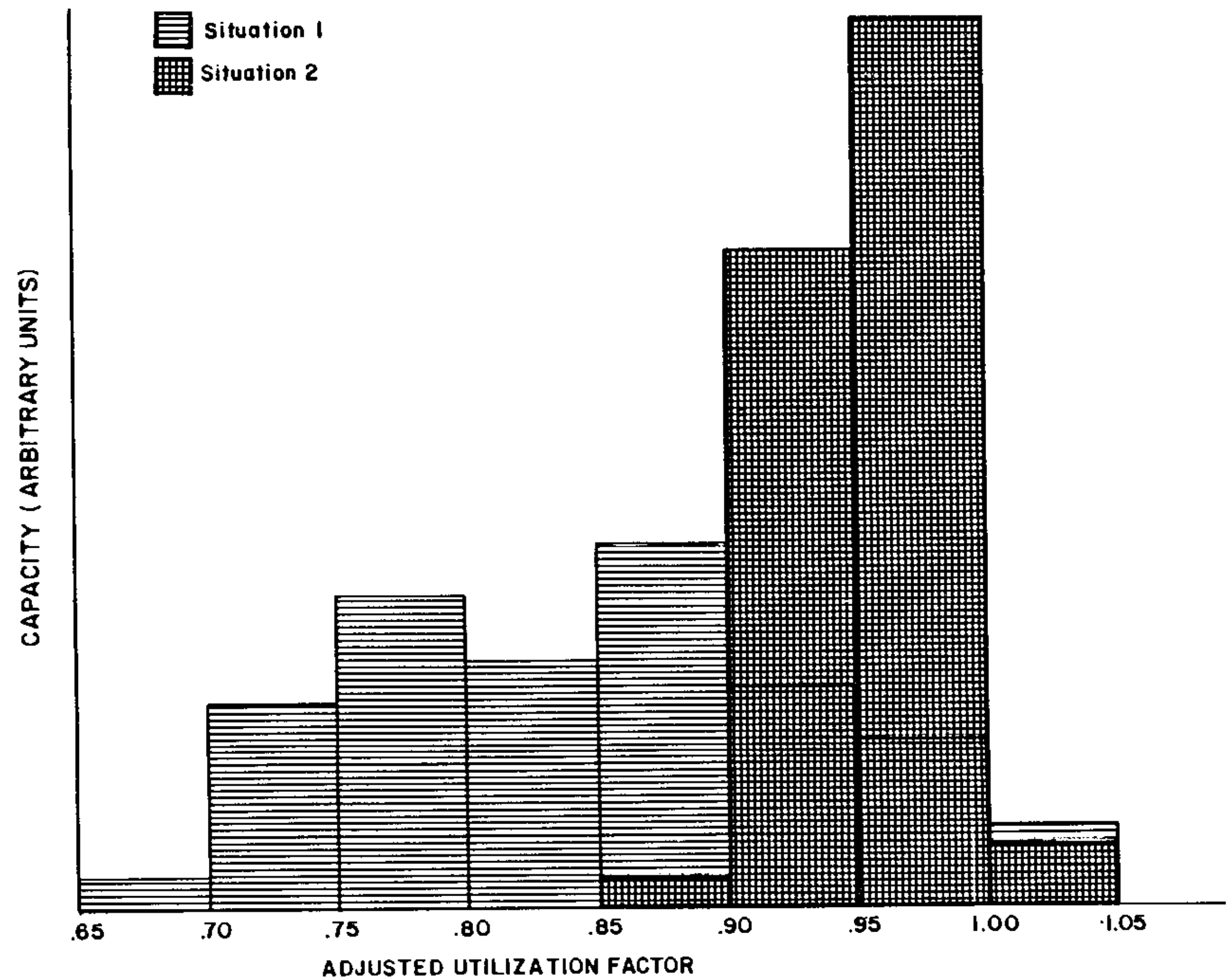

Figure 2. Substation Capacity at Various Utilization Factors for Two Utility Situations

In either situation, the average AUF for the utility is

$$\overline{AUF} = \frac{\sum^{n} K(AUF_i)\ AUF_i}{\sum^{n} K(AUF_i)}$$

where

$K(AUF_i)$ = kW of substation capacity at a given AUF

where the sums are over all the locales. The numerator is the total delivered peak power, D, while the denominator is the utility peak distribution capacity, C.

If the delivered power is the same in the two situations, $D_1 = D_2$ and $\overline{AUF}_1C_1 = \overline{AUF}_2C_2$ and the rates of increase of the two delivered peak powers are the same (and we have two steady state situations, where $\overline{AUF}$ does not change in time), then

$$\frac{.D_1}{\Delta t} = \frac{\Delta D_2}{\Delta t}$$

and

$$\frac{\Delta C_1}{\Delta t} = \left(\frac{\overline{AUF}_2}{\overline{AUF}_1}\right)\frac{\Delta C_2}{\Delta t}$$

Thus, the ratio of the two rates of expansion in distribution capacity is just the inverse of the ratio of the two $\overline{AUF}$s. Further, if the cost of building the extra distribution substation capacity in dollars per kW is S, the difference in annual expenditure for increased substation capacity in the two situations is

$$= S\ \frac{\Delta C_1}{\Delta t}\left(1 - \frac{\overline{AUF}_1}{\overline{AUF}_2}\right)$$

For the "not untypical" utility depicted in the figures, $\overline{AUF}_1 = 0.8$, while for a close to "ideal utility," $\overline{AUF}_2 = 1.0$. Therefore, the annual savings in substation reinforcement by an "ideal" targeting would be

$$= S\ \frac{\Delta C_1}{\Delta t}\ (0.2)$$

For a utility with a distribution capacity of 5 GW, expanding at the previous 3.8 percent a year, with a cost of substation capacity of $80/kW*, this expression leads to an annual savings of about $3 million.

Actually, this reduction in the annual cost of substation expansion significantly understates the possible savings due to locally controlling demand growth. In those years during which a utility is moving in the direction from situation 1 ($\overline{AUF}$ = 0.8) to situation 2 ($\overline{AUF}$ = 1), even greater savings are possible. It is simple to calculate these from the above model in a special case.

The previous calculation was of the annual savings accruing from a utility in situation 2 rather than in situation 1; two different steady state utility situations were compared. Consider now a utility that gradually changes from situation 1 to situation 2. For this example it is assumed that the change takes place in such a way that the delivered power is increased with <u>no</u> increase in substation capacity; it is done only by increasing $\overline{AUF}$. This is the (admittedly unrealistic) limiting case where <u>all</u> system expansion is achieved only in those locales where distribution capacity is underutilized. During the time in which $\overline{AUF}$is increasing toward unity, it is assumed no substation capacity is added.

The initial distributed power at the beginning of this period is $D_i = \overline{AUF} \times C$. When the distributed power is finally increased by bringing $\overline{AUF}$ to unity, it is $D_f = 1C$. The increase is $D_f - D_i = (1 - \overline{AUF})C$. If this same increase in delivered power were achieved by increasing distribution capacity at the original $\overline{AUF}$, $D_f - D_i = \overline{AUF} \times \Delta C$, where ΔC is the required increase in capacity. This leads to:

$$\Delta C = \frac{1 - \overline{AUF}}{\overline{AUF}} C$$

For the previous "not untypical" utility with $\overline{AUF}$ = 0.8, the avoided distribution capacity increase is: $\Delta C = 0.25C$. For a utility with 5 GW of distribution capacity and a cost of substation reinforcement of $80/kW, one would obtain an avoided cost of $100 million over the time period for bringing $\overline{AUF}$ to unity. If this transient benefit from upgrading $\overline{AUF}$ is achieved, the steady annual benefit calculated earlier would continue indefinitely.

*This is an estimate of a "not untypical" total cost of substation capacity increase, including labor, equipment, subtransmission, and real estate. This figure can vary widely with different situations.

These numbers are highly theoretical and idealized. They do, however, indicate that attention to these possibilities is warranted. The cost of achieving these savings by the targeting of already existing conservation programs could be quite small by comparison. These costs are discussed in Section 4.

STUDIES OF LOCALES OF DIFFERENT SIZES

Having identified the major cost component avoidable by reduced or deferred localized demand growth, and having presented a method for visualizing the magnitude of the potential savings, the question of the appropriate locale size for targeting efforts arises. The need to carry the discussion beyond the purely theoretical arguments in this subsection will be satisfied by a subsequent detailed analysis in terms of an actual utility, at two levels of aggregation.

It is frequently possible to balance loads inexpensively by reconnecting feeders within a set of substations. Indeed, this is the first response to localized demand growth. Thus, it is the load growth on such a set of substations (after appropriate feeder adjustments) that targeted demand-management efforts attempt to control. While such substation sets are not strictly definable, in practice it is a reasonable and commonly used approximation. Hence, the demand in an area served by a single substation set is the smallest appropriate target.

Targeting to an individual substation set can possibly delay a few million dollars reinforcement expense. The targeted program would have to be planned on a short term basis of a few years. The advantage would lie with "pinpointing" exactly the maximum savings in distribution expenses (and perhaps targeting a specific local situation).

If a larger area involving many sets had demand expansion so that a continuous reinforcement of capacity was required, targeting uniformly over the entire area could be appropriate. The "pinpointing" effect on single reinforcements would wash out. But on the average, the rate of capacity increase would be reduced. In this case, a long term, broad demand management effort could be mounted.

To investigate the potential benefit from targeting for actual utility systems, one must investigate the ratio of peak load to capacity for the transformers in use. There appears to be essentially no recent quantitative information on this in the public literature. Fortunately, the Pacific Gas and Electric Company

(PGandE) has been extremely cooperative in supplying data (and advice). Data at two levels of aggregation are used in the present study. The less aggregated level is that of sets of interconnected substations for which distribution planning is done on a transformer by transformer basis. Such individual project planning studies provide a richness of detail concerning planning trade-offs that is obscured in any more aggregated study. The price of this detail is a loss of generality as special circumstances dominate. Each of the project-level studies described below can be considered as a "not untypical" example of the various locales that might exist in any utility system.

At the first level of aggregation the move is almost to the opposite extreme. Here, the analysis is based on PGandE's thirteen operating divisions. Because the PGandE system is so large, most of the divisions are comparable in size to the entire utilities in some eastern sections of the United States. Many significant variations, as well as the distracting special circumstances, must surely be averaged. But important differences are still seen and the two levels of aggregation complement each other. Determining an optimal targeting program would require data and analysis at an intermediate level, as well.

The Thirteen Operating Divisions of the Pacific Gas and Electric Company

While small scale locale-specific effects must average out, data on the division level are readily accessible in the Company's Annual Statistical Report.

The degree to which the need for reinforcement of substation capacity is imminent depends on many locale-specific factors. For simplicity in this analysis, we focus on "utilization factor," as defined above. It is generally accessible by locale, and along with its rate of change, is a reasonable first indication of impending reinforcement need. More detailed locale-specific information can be considered later.

Figure 3 is a plot of each PGandE division's total 1981 nameplate capacity as a function of "utilization factor." The utilization factor used here is the 1981 ratio of the noncoincident peak loads through substations to the total substation

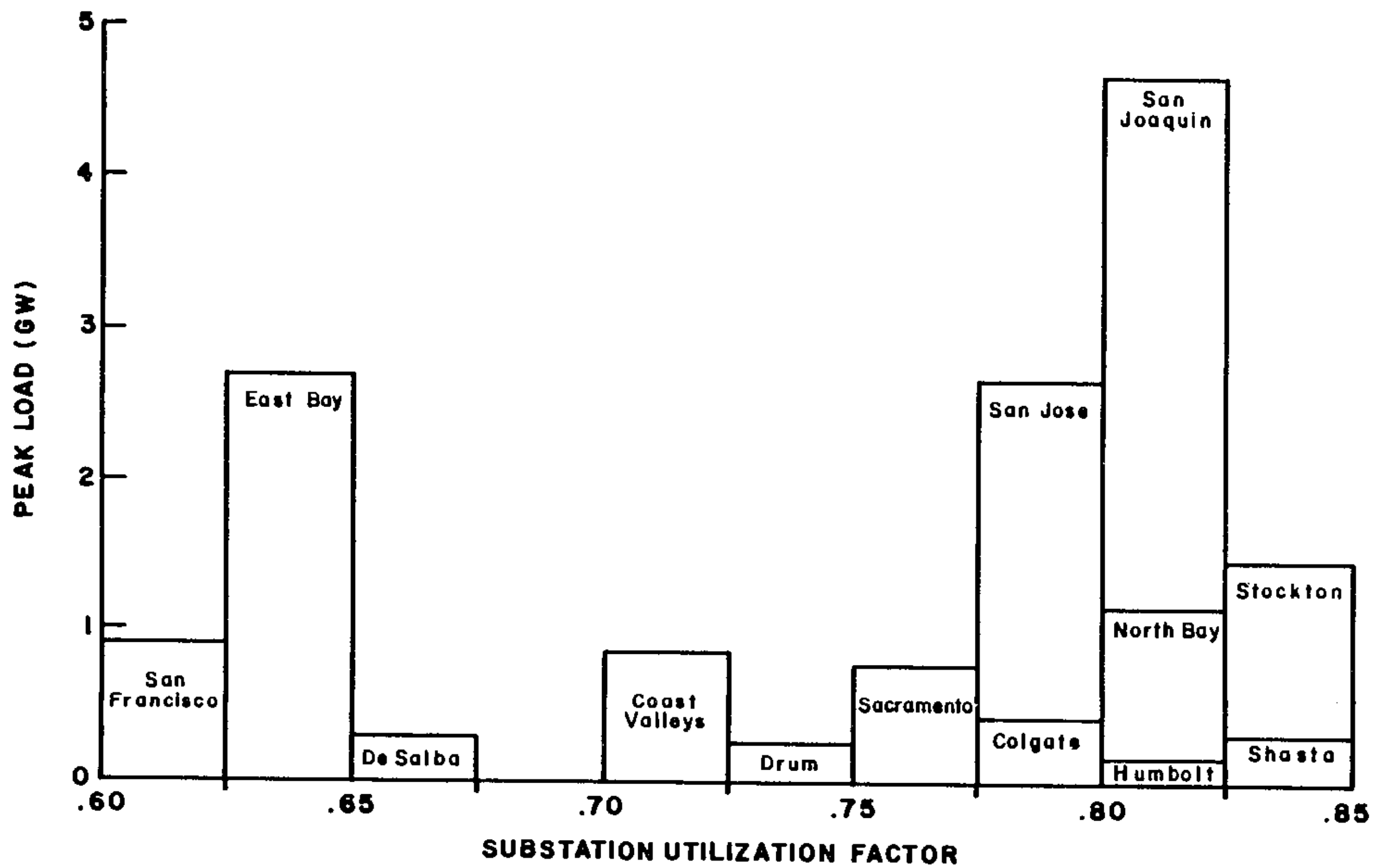

Figure 3. Total Nameplate Capacity as a Function of Utilization Factor for PG&E Divisions for 1980

nameplate capacity.* The figure here is a rough analog of Figure 1 in Section 3.3. The locations of the individual divisions are shown on the map in Figure 4.

The wide range of utilization factors among the PGandE divisions is immediately striking. The division boundaries to a great extent follow the natural geographical boundaries of an exceptionally diverse service area. The substantial diversity at the division level indicates that targeting of demand management on this level might be warranted. On this large scale it appears that minor administrative changes could bring about geographical targeting of the existing programs.

Could targeting bring about changes in the utilization factors within divisions? In this regard it is interesting to see how the utilization factors for the divisions have changed over time. This is displayed in Figure 5 for the five largest divisions, which constitute 75% of all sales. The fraction of the KWH sales for each division is in the first (single) parenthesis after each division name. While there is substantial consistency in time in the ordering of the divisions, considerable changes can occur in either direction in a year or two.

The fractional growth in peak load for each division in the 1974 to 1981 period is noted in the second (double) parentheses after each division name in Figure 5. Of the larger divisions, the two lowest in peak growth are also the lowest in utilization factor. This is a correlation that might be expected. To the extent that this level of aggregation does not wash out too many important locale-specific effects, efforts to reduce peak demand would more profitably be steered from these two divisions to San Jose, San Joaquin, or Stockton, provided they could be effective in reducing demand there. The high utilization factors for these divisions suggests that targeting efforts directed here would reduce capital expenses for distribution substantially more than in certain other divisions.

Further study of a number of factors, including the well known demographic trends in the various divisions, would have to be considered to formulate a targeting program at the divisional level in PGandE. This cursory look at the data, nevertheless, indicates that further investigation at the divisional level is warranted, and that a careful study at a less aggregated level could be valuable.

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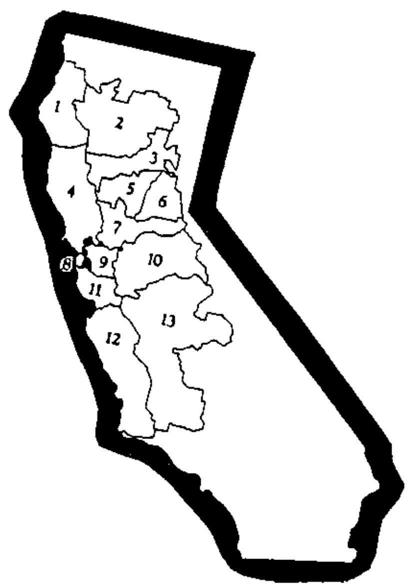
*Transformers can be efficiently operated above the nameplate capacity under certain circumstances. When the number of feeders connected is less than maximum, the capacity (normal capacity) is less. The error here in using the only data available is probably small compared to the variations being discussed.



1. Humboldt Division
2. Shasta Division
3. De Sabla Division
4. North Bay Division
5. Colgate Division
6. Drum Division
7. Sacramento Division
8. San Francisco Division
9. East Bay Division
10. Stockton Division
11. San Jose Division
12. Coast Valleys Division
13. San Joaquin Division

Figure 4. Divisional Boundaries of the PG&E Service Area

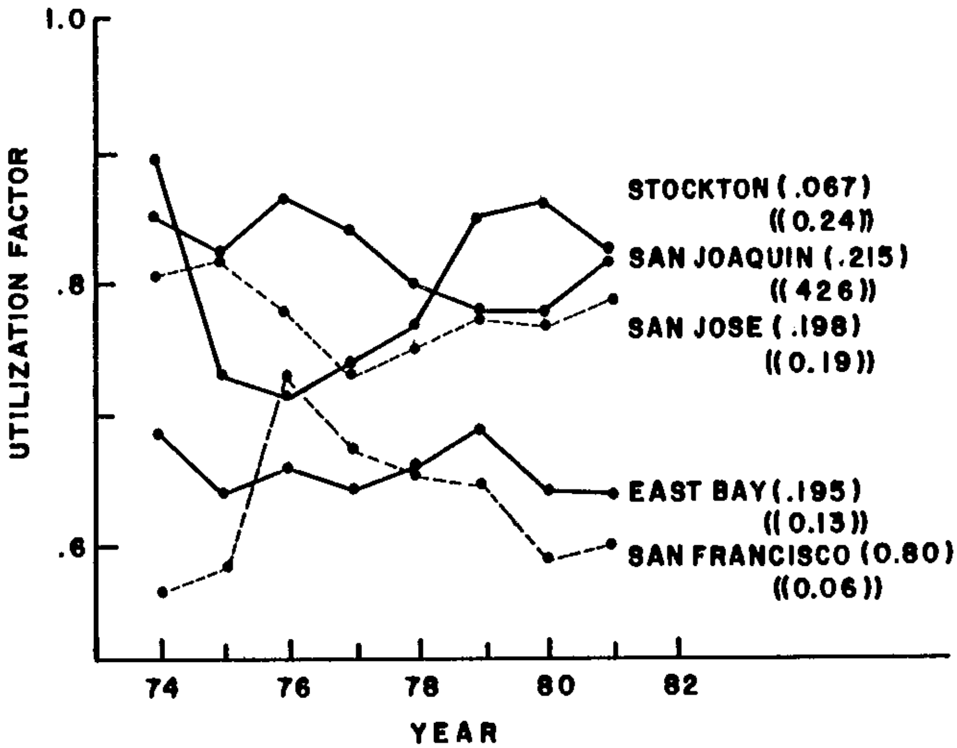


Figure 5. Substation Utilization Factor for Five PG&E Divisions

Three Locales in the Pacific Gas and Electric Company Service Area

This sub-section describes substation reinforcement requirements for three locales within the PGandE system: the Cupertino, Marysville-Yuba City, and Watsonville areas. The locales are outlined on the map on Figure 6.

The demand projections and anticipated reinforcements are reviewed as to whether expenditures could be deferred or avoided by a targeted demand management program that would reduce peak demand growth. Our conclusions are that a deferral of substantial expenditures is possible in the Cupertino case, if demand growth was slowed modestly, and that intensive demand management program appears to be warranted. In the case of Marysville-Yuba City, a targeted program would have a considerably lower payoff. In Watsonville, the situation is more complex and no conclusions can be drawn from the present data.

The conclusions stated in the above paragraph are based only on the information readily available from distribution planners. The information could quite easily be obtained by planners within the utility. They would, of course, use this only as a starting point. It would have to be supplemented by data on customer characteristics and considerations of what conservation and load management programs would be most appropriate.

The following sub-sections discuss the results of specific distribution planning to meet projected load growths. In order to examine integrating targeted conservation and load management programs with distribution planning, we must understand the mechanism of distribution planning. A discussion of this appears in Section 4, where the targeting process is discussed.

The Cupertino Area. The Cupertino service area of the San Jose Division is located in Santa Clara County. While contained within a highly populated region, it is a reasonably isolated unit (from a power distribution standpoint). It is bounded on the west and east by Palo Alto and Santa Clara, respectively, two communities that buy bulk power from PGandE and distribute it through their own municipal systems. To the south, the area is quite rural; to the north is the San Francisco Bay and some large customers with their own substations.

The area is served by 22 transformers in 10 substations feeding a 12 kV grid. There is a 4 kV grid which supplies only 1% of the power; it will not expand and is not a factor to consider here.

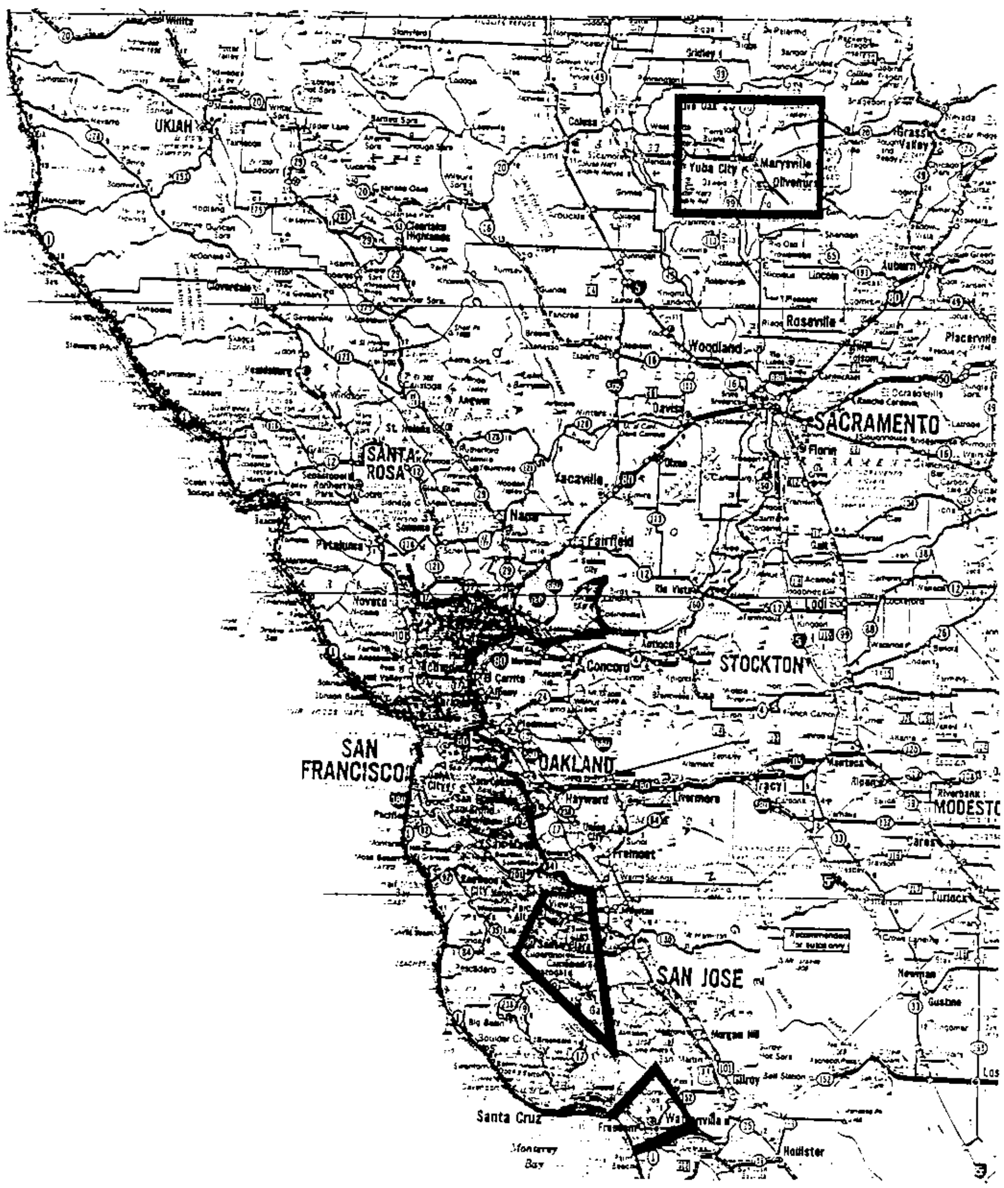


Figure 6. Approximate Locations of Service Areas Discussed in Section 3

The major issue in distribution planning in the Cupertino area is that of continuing to serve a large and rapidly growing peak demand. The substation transformers are almost all operating at utilization factors above 0.90. The distribution of utilization factors is shown in Figure 7.*

Peak load in the area has grown from 411 MW in 1974 to 546 MW in 1980 for an average annual growth rate of 5%. It has not always been steady, varying from 1.3% to as much as 10.2% in extreme years. Current working projections assume a continuous 5.5% annual peak demand growth. Since most of the transformers are close to their operating capacity, this may mean adding about one 30 MVA transformer per year and even building new substations.

The most immediate reinforcement plan is expensive, involving the Lawrence and/or Britton substations in the northeast sector of the 10 substation area.

Space limitations make this addition particularly difficult. A new substation nearby is another possibility to consider, but its cost is extremely high. The cost for reinforcement in the Cupertino area could go to several million dollars per year for the foreseeable future. Any confidently projected slowdown in the growth of peak demand in the Cupertino area would lead to an immediate reduction in the rate of capital expenditure for substation reinforcement. This is clearly an area in which careful examination of the potential effectiveness of targeted demand-management programs is warranted.

The need for major upgrading is so immediate, however, that a targeted program may seem ineffective. Nevertheless, it is estimated that 83% of the annual peak in that area is from only 700 commercial and industrial users, averaging 165 kW per customer. Only 10% of the peak in the Lawrence and Britton area is residential.

While a breakdown of the commercial and industrial users is not available, this area is the center of "Silicon Valley," and the homogeneity of industrial customer

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*The abcissa in this graph (and the similar ones in the previous subsection) is the ratio of peak load to "normal transformer capacity," or the capacity with those feeder lines presently connected to the transformer. The allowable peak load can be increased by adding feeders. The transformers are loaded in accordance with <u>ANSI Guide for Oil Immersed Transformers</u>, ANSI Publication number C57.92. The difference is a complication we presently ignore.

the last three years. Peak demand growth has ranged from a 17 MW increase in one year to a 2 MW decrease. PGandE's current working projection is for a 5 MW addition per year (which amounts to about a 3.3% increase this year).

The situation with regard to transformer utilization is shown in Figure 8. While the utilization situation displayed is not typical, it presents a substantial contrast to that in Cupertino as shown in Figure 7.

It would seem that with a 3.3% annual growth rate in the next few years there would be little need for substation reinforcement. Such is the case with two of the substations (Harter and Pease) in the northwest corner of the service area, which have shown particularly high peak demand growth and have utilization factors of almost 0.90. Consideration had been given to replacing a 10.5 MVA transformer at Harter or Pease with a 30 MVA transformer, but PGandE has decided that a transfer of feeder lines to other substations was more practical. Plans call for a review of the situation after studying the 1983 summer peaks, but it is likely that capacity additions will not be needed for several years.

Within the Marysville-Yuba City area the pursuit of conservation and other load management programs might emphasize the northwest sector fed by Harter and Pease. However, the entire Marysville-Yuba City area is not nearly so critical as, for example, the Cupertino area. The total PGandE conservation effort might most effectively be organized to emphasize areas like Cupertino, even at the expense of areas like Marysville-Yuba City.

The Watsonville Area. The Watsonville service area of the San Jose Division is in Santa Cruz County and is bounded on the west by the Pacific Ocean and on the north by rural areas. To the south and east are different operating divisions of PGandE, and interconnections to these are maintained primarily for emergency service.

The area is served by three substation transformers providing 21 kV primary feeders. There is also a substation providing 4 kV feeders to the older sections of the city of Watsonville. The 4 kV system will eventually be supplanted by a 21 kV system since, in general, 4 KV systems are not augmented today.

Distribution planning for the Watsonville area is complicated by the fact that any addition of transformers to the small number already there is a major increase

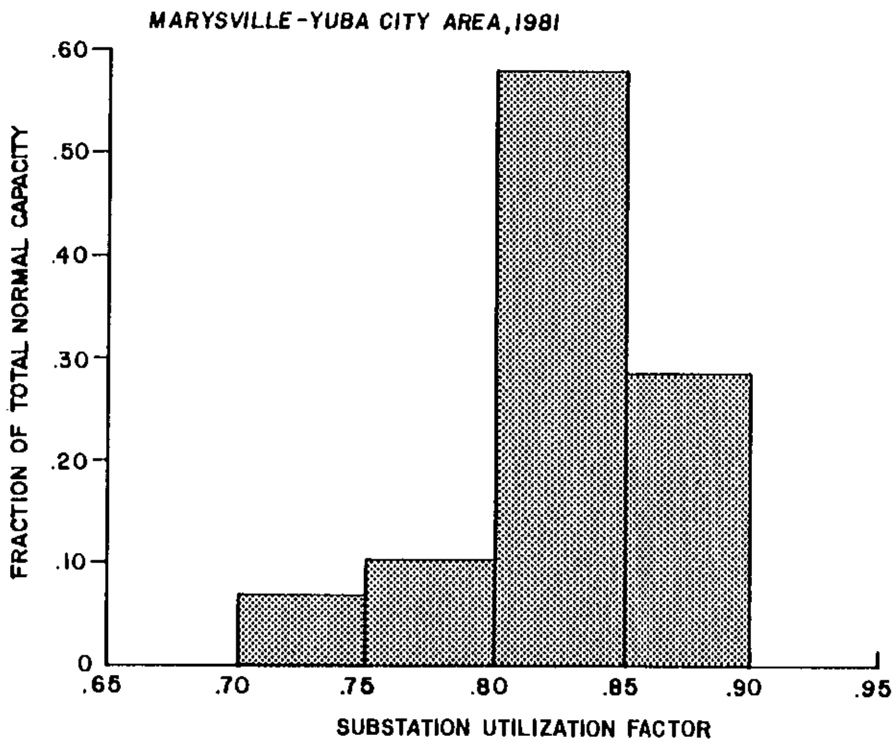

Figure 8. Distribution of Substation Transformer Utilization Factor for the Marysville-Yuba City Area

(and a qualitative change) in the system. The small number of transformers in this locale also means that as the transformers approach their full ratings new equipment must be added to maintain distribution reliability. The size of the area is also large, and line losses are a significant consideration.

Longer term plans involve adding a new transmission line from the nearby Moss Landing power plant. Currently, there is no established distribution reinforcement plan for the area. Quite different scheduling plans are still under consideration.

The three substation transformers supplying the 21 kV feeders range in peak-load-to-normal-capacity-ratio from 0.69 to 0.86. (See Figure 9.) The weighted average of this ratio for the locale is not far from the PGandE systemwide average, but the fact that the ratio for one transformer is getting close to unity signals the possibility that some targeting could be warranted. The old 4 kV transformers are lightly loaded (about 0.45), but the 4 kV distribution system is about 20% of the total. Since this low voltage distribution system will eventually be retired, any expansion of service in the area would likely be at the 21 kV level, and thus require substation transformer additions. The transformer situation in itself does not present a clear case for or against targeting conservation and other load management programs in the area.

The peak demand growth in the Watsonville area does not give a definitive pattern for projections. From 1974 to 1979 the peak grew from 57.12 MW to 77.4 MW for an annual growth rate of 6.2% for the five year period. In the next two years the peak demand actually dropped with a negative growth rate of 0.5%. The average for the seven years is 4.3% growth. This last number might indicate targeting since it is substantially higher than the PGandE systemwide average of 2.5% peak growth over the same period.

PGandE distribution planners currently use a projection of 3 MW annual growth for the area. In the past seven years, growth has varied from 7 MW to a negative growth of 0.5 MW. The reasons for the variation are only partially understood, and the distribution planners must accept substantial uncertainty.

Adding uncertainty is Watsonville's accessibility to the rest of Santa Cruz County, which is experiencing strong population and industrial growth pressure from neighboring Santa Clara County (Silicon Valley). The growth of Santa Cruz

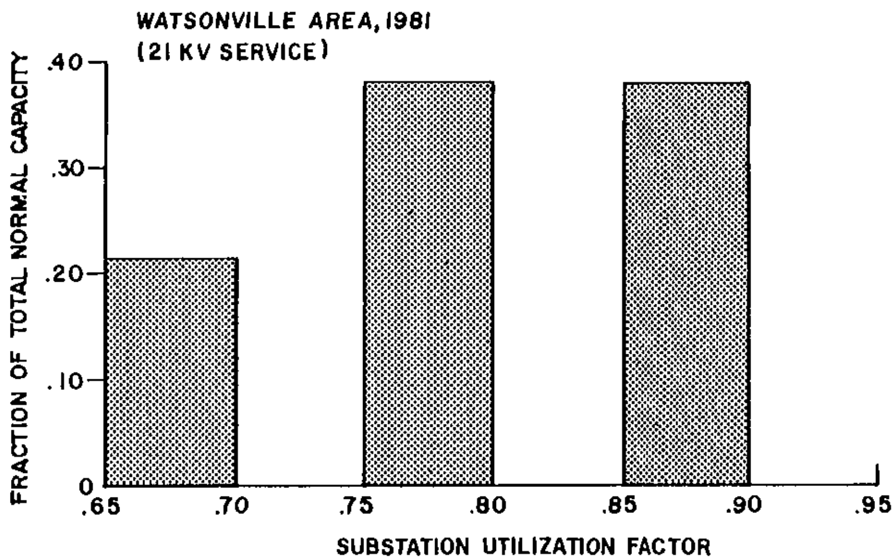

Figure 9. Distribution of Substation Transformer Utilization Factor for the Watsonville Area

County has been limited up to now by a combination of local statutes and citizen opposition to growth. The growth projection could be altered substantially should the County's political/legal situation change.

Without explaining the various possibilities of the complex electrical situation, and ignoring a likely transformer addition to take care of emergency loads, we note the consideration of some very expensive capital budget items. The largest of these is a transmission line from the Moss Landing plant at a cost of over ten million dollars. One reinforcement possibility includes the addition of this line in 1987, and another allows this expense to be postponed six years to 1993. The timing depends on whether the Watsonville 4 kV substation is upgraded by the addition of a 21 kV transformer ($1.3 million), or whether an outlying substation, Green Valley, is reinforced ($3.3 million). Which action to take could depend on the character and location of the potential growth in the area and the planners' confidence in such projections.

Finally, while peak load by user class is not readily available, over half of the energy demand is summer peaking, resulting from industrial and agricultural use such as cold storage, food processing, and warehousing. The number of these customers has increased only 3.8% since 1974, but their energy usage has increased 6.3% in the same time (substantially greater than that for other user classes). It appears that a targeting effort toward this customer group could be effective.

In conclusion, the projected load growth in the Watsonville area could influence decisions on major capital expenditures. The character of the dominant users seems to indicate that a targeted demand management effort could be successful, and that the time available for accomplishing the needed reduction in demand growth is adequate. A careful look at the potential merit of targeting this locale is warranted.

SUMMARY OF THE POTENTIAL BENEFIT OF LOCALLY CONTROLLING DEMAND GROWTH

To assess the benefits of controlling demand growth (by targeting conservation and load management programs) in locales where the cost of supplying service is greatest, the factors affecting these locale-specific costs must be investigated. The major avoidable factor is the cost of reinforcing substations in areas where demand is growing rapidly and where the substations are already operating close to capacity. Avoidance or deferral of capital expenditures to reinforce substations would be an appropriate goal for a targeted demand-side management effort.

A model for calculating the total deferred or avoided capital expenditures possible with an ideally effective demand growth management effort (targeted conservation and load management programs) indicates considerable potential. The technique involves examining the distribution of substation utilization factors over the sets of substations which make up a total service area.*

In order to examine a realistic situation, the Pacific Gas and Electric Company has been studied at two different levels of aggregation. The first is by the thirteen divisions into which PGandE divides its service area. These show a substantial variation in average utilization factor and indicate that some targeting by even these very large geographical blocks might be warranted.

A much more detailed study has examined three different reinforcement situations in three diverse locales. The initial conclusion is that one warrants an intense, immediate targeting effort, another warrants far less effort (at least in terms of distribution system capital expenditure savings), and the third has a potentially large benefit, but needs further study. Capital expenditure deferrals of a few million dollars for a few years are typical of the magnitudes considered in each targeting situation.

To summarize, it appears feasible to identify geographic areas with considerable potential for benefits in the form of reduced capital expenditures. The remaining question is whether demand management programs can be effectively targeted to such areas without offsetting disadvantages. This issue is addressed in the next section.

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4. Ponnavaikko, M., and K. Prakasa Rao, "An Approach to Optimal Distribution Planning through Conductor Gradation," IEEE Transactions on Power Apparatus Systems v. PAS-101, 1982.

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Section 4

THE EFFECTIVENESS OF TARGETING CONSERVATION AND LOAD MANAGEMENT PROGRAMS BY LOCALE FOR CONTROLLING LOCAL PEAK DEMAND GROWTH

Section 3 identified savings in capital expenditures accruing from reduced peak demand growth in locales where substation reinforcement might otherwise be needed. The following questions may now be posed:

1. How effectively can demand growth be managed by targeting conservation and load management programs to the locales where reduced growth is most desired?
2. What are appropriate mechanisms for such targeting and what are possible impediments or disadvantages?

This section describes and evaluates potential external constraints upon targeting conservation and load management programs. It includes a description of the existing legal and regulatory mandates or guidelines, and assesses whether public or political perceptions are likely to modify them in a manner that would restrict targeting efforts.

We then discuss how a generic targeting effort might be implemented within a typical utility, assessing potential internal constraints to developing a successful program. Specifically, targeting efforts will require interaction between the utility's distribution and conservation planning processes.

The efficacy and cost of geographically concentrating conservation and load management programs are then examined. This includes describing and evaluating specific programs to assess their compatibility with targeting criteria. We also address the concern that a geographic concentration of these programs might adversely impact systemwide goals for reductions in energy use and peak demand. Finally, we summarize discussions with PGandE conservation and load management personnel in the Cupertino area to gain the perspective of practitioners in the field.

CONSTRAINTS ON LOCALLY CONTROLLING DEMAND GROWTH FROM OUTSIDE THE UTILITY

Utility conservation and load management programs are subject to formal and informal mandates or guidelines emanating from state and federal law, public utility commission jurisdictional review, and public/political pressures. The nature of these constraints varies with the scope and structure of particular conservation or load management programs. As a rule, the larger the scale of these programs and the greater their costs, the more explicitly the constraints are expressed.

Federal involvement in this area consists of a national policy that seeks to utilize scarce energy resources more effectively. This has led to the development of federally-approved state conservation plans that affect utilities.

The states help implement the federally-mandated utility programs, which are designed to promote conservation and load management efforts by each of their customers. These mandatory programs, however, do not permit full-cost recovery by the utility from those customers who participate in the programs. To the extent that recovery is permitted, it is only through the general rate base as determined by state regulatory authorities. Additionally, some states, such as Michigan, California, and Arkansas have passed legislation defining the general framework to which certain utility programs must conform. In other states, public utility commissions have asserted authority over utility conservation and load management efforts. Often, the public policies which have evolved in this area have been strongly influenced by local constituencies.

A fundamental reason for public policy constraints on utility programs is the perception that costs and benefits might not be equitably distributed. Conservation and load management activities primarily benefit the utility customer who adopts more efficient practices. In addition, society and the utility benefit by avoiding high cost marginal supplies. But when utility programs institute rate increases to fund their costs, nonparticipating ratepayers are affected.

Federal Law/Regulation

Utilities have been federally mandated to develop programs which foster energy conservation and load management by their customers, but have been discouraged (in many cases, precluded) from having a business interest in selling or installing conservation and load management equipment. The applicable federal statutes include: The Energy Policy and Conservation Act, the Energy Conservation and Production Act, the National Energy Conservation Policy Act, and the Energy Security Act.

Each of these acts has been amended several times. In concert, federal law and the regulations implementing them have (1):

- led to the development in most states of federally-approved energy conservation plans, many of which impact utilities
- created the Residential Conservation Service and the Commercial and Apartment Conservation Service, which require utilities to offer all their residential and commercial customers low cost energy audits and provide them with suppliers, installers, and lenders for implementing conservation measures; full-cost recovery is generally granted, as specified by the state rate-making authority
- required utilities to aid in development of federally-approved experimental conservation programs through contracts with suppliers and contractors to install experimental measures
- discouraged (in effect, prohibited) utilities from having a business interest in the supply and installation of conservation measures for their customers
- created authority for federal funding of incentives that assist residential, commercial, industrial and local governments in financing conservation measures.

Changes in funding allocated to federal incentive programs and to monitor regulation compliance can significantly affect these laws' impacts on utilities. The current administration, for example, has minimized federal control and involvement in this area. Thus, there is a trend toward modification of federal regulations to mandate only those items specifically required by law and to allow the utilities more flexibility. Any needed regulation is provided by individual states. However, federal funding of incentive programs for implementing conservation and load management measures by residential, commercial and industrial customers has been drastically reduced. Normal market forces (i.e., higher energy prices) are believed to be proper and sufficient motivations for implementing such efforts. In the short-term, this may render the utility programs less effective.

State Law/Regulation

The principal regulatory review of utility conservation and load management programs emanates from state public utility and energy commissions. Many states have formalized criteria for evaluating conservation and load management programs. The most well-established of these is the non-participant test originally developed by utilities and regulators in the Pacific Northwest. Their approach defines an economic limit on the costs and incentives that utilities can offer to program participants. The interest of the non-participant is protected if rates do not increase over the life of the program any more than they would have without it. On a per unit basis, this means that the costs of a program can be no more than the difference between marginal cost and marginal revenue (2).

In California, utilities believe that an appropriate test compares the unit cost of savings with the marginal cost of new supply (3). While this test is less restrictive than the non-participant test, both define economic criteria, which measure the relative merits of programs.

As a consequence of using such criteria, de facto geographical targeting of programs often results. For example, the benefits of weatherization programs can vary widely with locale-specific climate conditions, yet the costs of such programs do not typically show much variation. Southern California Edison Company (SCE), for example, has developed weatherization impact assessments for seven climate zones in its service territory (4). The impact of weatherization measures varies by as much as an order of magnitude, and a factor of two difference is common. Consequently, SCE's weatherization program is more cost-effective (by any standard criterion) in the extreme climates. The differences are so substantial that the program ends up being implemented widely only in the extreme climate locales. In this example, targeting results directly from benefit variations.

Currently, explicit targeting of utility conservation activities has been primarily restricted to low-income customers or other special needs groups. The main motivations for these targeting programs have been the limited resources of such customers and the heavy burden of energy prices. Nonetheless, regulatory commissions have also shown concern that targeted programs not unduly discriminate in favor of participants to the disadvantage of other customers. Low income conservation programs may actually involve some de facto geographic targeting effects, but these are not explicit features of their design.

Special utility programs involving explicit geographic targets are not unknown. Consolidated Edison has recently instituted a special "area development" rate for new business customers in certain depressed regions of its service territory (5).

While the primary purpose of this program is to spur economic development in these locales, its success will have beneficial financial effects for the utility. With increased economic activity in these areas, existing distribution facilities will be utilized more fully, thereby increasing the overall efficiency of operation. Pacific Gas and Electric has two conservation and load management programs that are necessarily local in nature. These two programs, Group Load Curtailment (GLC) and Cooperative Electricity Management Program (CEMP), are described later in more detail.

Any regulatory review of a program that discriminates by customer need, geographic region, or any other criterion will ascertain whether the discrimination is appropriate. Typically, state legislatures grant regulatory commissions the power to make such judgments.

The most common rationale for programs which provide different economic costs and benefits to different customer groups is cost of service. This is the standard basis for differentiating rates by customer class. Regulatory review of conservation programs usually follows this pattern. The use of a cost-effectiveness test for such programs is an extension of cost-of-service ratemaking.

Early applications of these tests have commonly been made on a measure by measure basis. The utility will only encourage a given action if the incentive for that action is cost-effective by itself. At a later stage, when conservation programs are larger in scale, it is common to broaden the cost-effectiveness test by applying it to a portfolio of measures. Puget Sound Power and Light, for example, has recently altered the evaluation of its residential weatherization program to a "whole house" basis (6). Instead of requiring that each element of a weatherization job meet the cost-effectiveness test, the "whole house" method requires only that the sum total of measures installed for a customer pass the test. This amounts to an average of high and low productivity measures. Such averaging can be applied at higher and higher levels of aggregation. As the size and number of conservation programs increases, there probably will be more of such averaging. Informal conversations with staff members of the California Public Utilities Commission raised this point and indicated a desire to move away from providing guidance over the specific details of program implementation.

Even in those states where laws regarding utility conservation policy have been enacted, legislative guidance is necessarily general. The language of a Michigan statute, for example, implies that the non-participant cost-effectiveness test is the relevant measure, since it limits programs to a level that would not raise the costs to the non-participants (7). Nonetheless, it is the regulatory commission that interprets these tests and chooses the degree of vigor with which they will be applied. This result has been echoed by California's judicial system, where the Public Utilities Commission was challenged by both industrial customers and consumer-interest groups over the equity of its conservation program decisions. Neither of these challenges was sustained in the courts, indicating judicial reluctance to second-guess regulatory commissions.

Implications of Existing Laws and Regulations on Locally Controlling Demand Growth

Existing laws and regulations on federal and state levels do not explicitly address targeting concerns. They do, however, mandate and prescribe specific guidelines for the implementation of particular conservation and load management activities by utilities. Furthermore, cost-effectiveness tests for these activities provide a framework in which targeting efforts may actually enhance the efficacy of such programs; because targeting seeks to reduce capital outlays for distribution substations.

Where utility conservation and load management programs are explicitly local in nature, regulatory review will probably be required before implementation. Such review will typically be more intensive if program participants will be offered some economic incentive not available in other locales. The appropriate test of such programs will probably entail cost-of-service. Provided that tangible avoided cost benefits can be shown to follow from locale-specific conservation and load management programs, regulatory approval will be likely.

Such approval has been the experience of California utilities. As the number of conservation and load management programs has increased and the scale of each has grown, regulators have been increasingly willing to allow substantial managerial discretion over implementation details. Locale-specific programs have been approved in the general context of a cost-effectiveness demonstration. This pattern will probably be repeated in other jurisdictions. As regulators and utilities become more familiar with conservation and load management activities, the benefits of geographic targeting will fit naturally into the cost-effectiveness evaluation.

In summary, geographic targeting of conservation and load management programs is unlikely to be seriously contrained by existing laws and regulations and, in fact, may be valuable to utilities mandated to design and implement cost-effective conservation and load management programs.

<u>Perceptions of What is "Fair" in Conservation and Load Management Programs</u>

As we have mentioned, regulatory policies do not govern geographic targeting of conservation/load management programs. Guidance in these areas must be by implication.

Utility conservation staff members raised the questions of what would be viewed as permissible, fair or equitable.

Perceptions of fairness involve questions on which a wide range of opinions can be defended. In terms of geographical targeting, some experts foresaw significant impediments, while others predicted no problems at all. These differences in opinion usually depended on how the individuals saw targeting efforts being implemented, and on their views of the future regulatory environment. The attitude taken by the utility may be the deciding factor in advancing or rejecting targeted programs.

The factors involved, however, are too situation-dependent to analyze in general. We, therefore, list here several questions regarding a targeting effort's time, place, and implementation mechanism.

1. Do the targeted programs meet the fairness tests (e.g., the non-participant test or cost of marginal supply test)? Since benefit to the customer accrues through reduced capital expenditures by the utility, these tests are particularly important. Because the cost of targeting may be small, an affirmative answer to this question could be easy.

2. Will "equity" be required on a program-by-program basis? Or must the entire package of conservation programs meet the fairness criterion? As the number of different programs increases and a general sophistication with regard to conservation and load management develops, a specific program is less likely to be looked upon in isolation.

3. How will future regulatory policy effect conservation and load management programs? Some regulators are disinclined to address specific programs. Rather, they encourage utilities to propose conservation packages to accomplish the overall objectives.

Any means for improving distribution planning, with respect to future demand in a locale, would be welcomed. If, in addition, planners could actively influence such demands to suit the distribution situation, the utility, ratepayers, and society would benefit.

Methodology for Introducing a Locale-Specific Management Program

With the above discussions of the distribution planning situation emphasizing the problems faced today, the stage has been set to discuss a methodology for the introduction of a localized demand management effort. The specifics will depend crucially on the types of conservation and load management programs that incorporate locale-specific demand management criteria. Examples of these types of programs will be discussed below; the discussion here will be confined to those aspects which would be common to all targeting programs.

Motivations for the Introduction of a Locale-Specific Demand Management Program. New programs are often proposed to individuals who already consider themselves overburdened with problems, and who view any disruption of their routine as annoying and even threatening. The introduction of new programs can be facilitated substantially, if the individuals involved see how the program's success could benefit their own work. With a locale-specific demand management program, such motivations exist for the different groups involved:

- Corporate and Mid-level Management Personnel: The likelihood and significance of postponing capital expenditures in itself provides substantial motivitation, provided that the effort will not require organizational changes or internal challenges.

- Distribution Planners: These individuals are pressed to plan equipment additions within the narrowed limits of under and overbuilding, despite uncertain predictions. Targeting conservation and load management programs will open the window for acceptable decisions on distribution augmentation by enabling the utility to actively influence load growth in specific locales. Further, their work in analyzing distribution facilities and the initially projected growth becomes more important to the company because it now also, without additional effort, provides information necessary for a coordinated demand management plan.

- Conservation and Load Management Program Personnel: The goals of conservation and load management managers involve mandates from outside the company. Involvement in a program with the fairly short term internal goals of capital expenditure limitation should be welcomed. Also, locale-specific targeting of conservation and load management activities provides the best tests of these efforts' effectiveness.

A Specific Technique for a Locale-Specific Demand Management Program. Targeting efforts should be gradually introduced into existing utility structures. A separate program with new personnel is not foreseen. Targeting is a new approach in designing conservation and load management efforts. Therefore, a given utility should assess the merits (and cost) of the approach experimentally before applying it throughout its service area. In fact, the tests are built-in and, in only two or three years, the programs should be able to demonstrate their effectiveness and prove their worth.

To clarify how targeting programs can be instituted, we will use a mechanism employing a simplified view of the distribution and conservation planning processes. This view and the possible modifications required for targeting follow.

First, the distribution planner projects kilowatt demand for a locale* and derives a tentative demand growth rate, as in Figure 10. This is a plot of past and predicted peak load on the substation set whose eventual reinforcement is being considered. All analyzable factors, including the systemwide conservation effort are presumed implicit in these predictions. The time-scale might extend as much as a decade into the future. The horizontal line is the chosen peak load at which reinforcement would be required for efficient and safe operation. Growth uncertainty is indicated by the lines bounding the shaded region. On the basis of various locale-specific factors, a reinforcement is scheduled within the "time window" indicated by "a" and "b." Distribution planners must schedule construction well before time "b" or risk very costly consequences of underbuilding, and they must avoid building before "a" or be criticized for wasting scarce capital resources by overbuilding. Since "a" and "b" are both uncertain, this decision is difficult.

A targeted conservation program would begin by giving Figure 10 type graphs to the conservation and load management program planners. They in turn would evaluate

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*Ideally, a "locale" is a set of substations which are so inter-connected that the load can be redistributed among them, but also isolated from other substations so that load cannot be transferred from them without major expense. Only rarely is a "locale" so clearly definable. Usually, the locale, for distribution planning purposes, can be thought of in several ways. This is a complication that distribution planners routinely confront. Instead of the graph below, a number of graphs could be presented. They will, in large part, be based on the different reinforcement possibilities. Since the areas will be largely the same, the analysis for the conservation targeting planning will be similar.

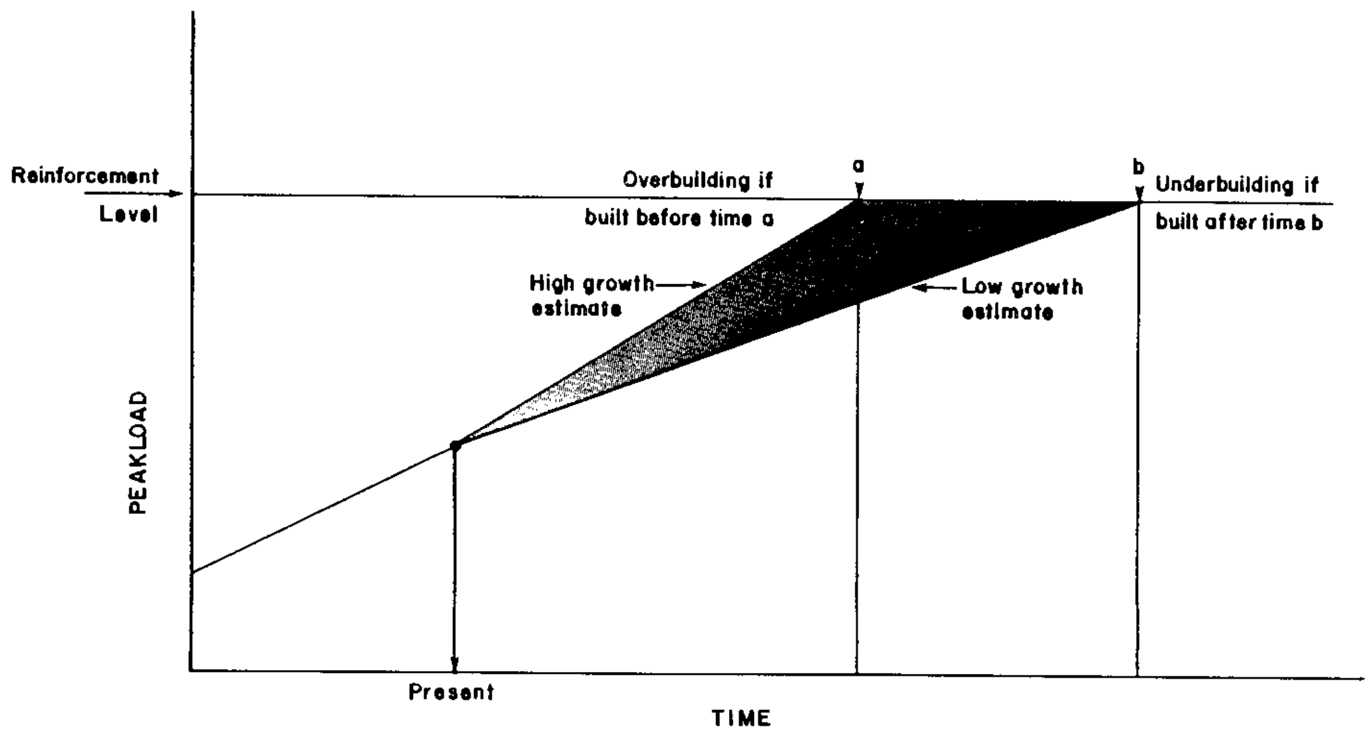

Figure 10. Peak Load Projections for Substation Reinforcement

the peak load growth reduction potential of the region and estimate the targeted programs' impact on peak load growth for that locale, and modify growth projections as shown in Figure 11. The distribution planners could then decide to recommend postponing the scheduled reinforcement as indicated, with the consequent capital expenditure deferment. If they decide to postpone, they would notify the conservation and load management planners of the modified schedule, thereby accepting their plans for managing energy demands through conservation and load management programs.

The conservation and load management people would then reorder their priorities, budget, and personnel assignments to concentrate on the targeted locale.

Consider the impact of this interaction on the two groups who will work together for perhaps the first time. For the distribution planners, there has been very little extra work and almost no added responsibility. They also have a distinct advantage - more time in which to apply various locale-specific factors. The time window is now effectively from "a" to "d" in Figure 11, rather than from "a" to "b." Why from "a" to "d" rather from "c" to "d" as the conservation planners outlined the uncertainty? This is because the projected targeting conservation is controllable, unlike the former growth prediction. If it appears with time that the rescheduled reinforcement is too soon, and "overbuilding" is a possibility, the "too effective" demand management program can be turned off, and the conservation and load management efforts placed elsewhere in the system. It appears that the distribution planners have an almost no-lose situation in this procedure.

The conservation and load management people now have the ability to attack a problem that will directly aid the utility. Since the programs produce measurable results, these people also have the means of gaining recognition for their activities. Of course, failure to achieve what is projected is also documented. But then sticks as well as carrots can be motivating.

This interaction channel between distribution planners and conservation and load management planners is a narrow one, but in principle it seems to be sufficient, since the exchange required is explicit. The actual mechanism by which conservation and load management planners set out to accomplish a concentrated effort in the targeted locales will depend on the particular programs to be targeted. This will be discussed in a later section.

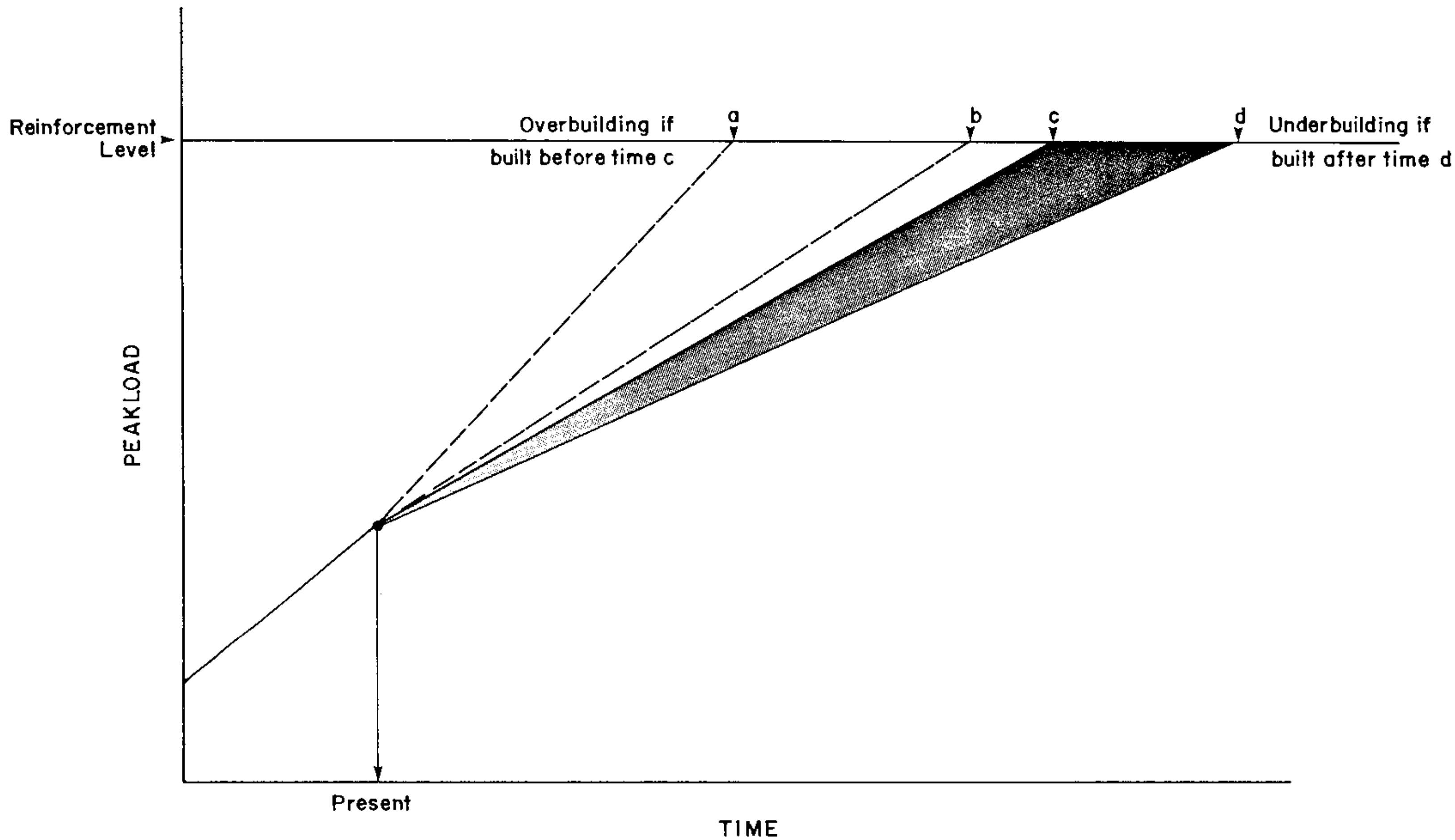

Figure 11. Peak Load Projections for Substation Reinforcement With Targeted Demand Management Effort

Thus far we have described the first form of an organizational adaptation required by a targeting approach. Its accomplishments will surely be limited. However, the purpose is to demonstrate that such efforts can be cost-effective overall and undisruptive if properly planned. Expanding the approach to the entire utility would then be possible since its planning would consider the problems encountered (and solutions) based on actual experience.

Clearly, if only a few utilities initiated test conservation targeting efforts in the near term (each with adaptations suited to their specific situation), a wealth of information would emerge showing the merits and pitfalls of various detailed approaches. If in turn such information were shared among utilities, the reasonably quick implementation of conservation targeting approaches by the utility industry could ensue.

EFFICACY OF GEOGRAPHICALLY CONCENTRATING CONSERVATION AND LOAD MANAGEMENT PROGRAMS

This section begins with an examination of five examples of utility conservation and load management programs with respect to their suitability for geographic targeting. It is not our intent to develop criteria for determining which programs should be selected for targeting or how selected programs should be targeted to a specific locale. Rather, we wish to evaluate a few examples of existing programs in terms of the targeting approach and to assess targeting's implications for meeting other conservation program goals. The positive result of these assessments demonstrates the feasibility of targeting at least certain existing programs. Others, even more suitable, could no doubt be developed.

The programs examined include:

- Comprehensive Community Energy Management Program
- Cooperative Electricity Management Program
- Group Load Curtailment
- Load Management Planning for Large Commercial Customers
- Load Management Planning for Small Commercial Customers.

The following subsections briefly discuss each of these programs by examining:

- how recipients are selected and how modifications to the selection process might effectively target the program

- cost implications of targeting.

The final subsection examines the systemwide effect of targeting upon conservation and load management programs. That is, a key concern not explicitly addressed in the descriptions of individual conservation programs is that aggressive targeting in a locale might, because of saturation effects, reduce overall conservation program effectiveness in meeting its primary goal of reducing systemwide peak demand and energy use.

Specific Targetable Programs

A number of end-user energy conservation and load management approaches could be considered for inclusion in a geographically targeted effort that addresses the reduction of capital expenditures for substations. Because the benefits of such targeted efforts are avoided capacity costs, load management programs will have the best chance for implementation. It should be noted, however, that significant peak load reductions can be achieved by more common energy conservation measures including weatherization, the installation of more efficient heating, ventilating and air conditioning equipment, lighting, and appliances. In this section, several existing energy conservation and load management programs are reviewed to assess their potential as a method for achieving peak load growth reductions in locales served by a substation or a closely coupled set of substations.

Only recently have systematic attempts been made to assess the value and efficiency of energy conservation and load management programs. Efforts such as a recent workshop held in Columbus, Ohio, sponsored by the Electric Power Research Institute, on measuring the effects of utility-sponsored conservation programs, and a recent conference organized by the American Council for an Energy Efficient Economy on "What Works?" are only beginning to create a valuable record of various energy conservation approaches.

This lack of information was emphasized in the "EPRI Perspective" to the workshop proceedings (8), which noted that the participants had considered the question of "end-use management versus supply expansions" and identified five unresolved issues:

- Impact of residential conservation programs on peak loads
- Impact of commercial and industrial conservation programs

- Impact of load management programs
- Transferability of program impacts from one utility service area to another
- Cost-effectiveness of energy and load management programs.

As a result, we have reviewed specific utility company efforts and preliminary data from other ongoing studies to develop our findings. A more definitive understanding of the potential for geographically targeting conservation and load management programs would require considerable primary research.

Comprehensive Community Energy Management Program. The Comprehensive Community Energy Management Program (CCEMP), sponsored by the U.S. Department of Energy, provided over a dozen communities with planning and technical assistance in running an energy conservation program for the citizens in that community. The program focused on residential and commercial energy conservation, by means of disseminating information with self-help and financial assistance elements to help lower income participants achieve energy savings.

Examples of community energy conservation programs that have achieved significant energy savings for their customers include programs in Fitchburg, Massachusetts; Davis, California; and Portland, Oregon. Their success is usually attributed to an aggressive, dedicated group of individuals who have actively supported the effort. Techniques for outreach to citizens have included advertising, direct contact and local meetings, all aimed at informing and generating response.

One of the conservation measures frequently implemented through CCEMP programs involved residential weatherization. Such weatherization retrofit programs have been found to reduce peak loads as well as kWhs. The savings are generated in a wide but geographically defined area. For example, the Oklahoma Gas and Electric Company (OG&E) has developed some specific estimates of summer peak reduction resulting from home insulation programs. OG&E retrofitted 65 homes with R-8 ceiling insulation to bring the level to R-19. Comparing 1980 and 1978 performance, the utility found a .36 kW reduction per home (7.1%) (9). Looking at average peak demand for the top 10 systemwide peak demand days, they noted a .4 kW decrease per home. For the highest single demand on circuit coincident with system peak, they noted a .41 kW decrease per home (8.8%). Considering average peak demand coincident with system peak on the highest peak days, there was a .58 kW decrease per home. OG&E reported an overall demand reduction of 7% when the outdoor ambient temperature was 100 degrees Fahrenheit, and 13% at 105 degrees F.

Oklahoma Gas and Electric's experience demonstrates that a straight-forward residential conservation program can reduce local kW demand. Since such general conservation programs, which stress insulation, weatherstripping, setback thermostats, and adjustments in comfort levels, are frequently managed on a community wide basis, potential exists for a community-focused energy conservation program that can also address distribution system needs.

Such programs, however, raise two problems. First, they require cooperation of individuals from the community, and second, the locale must have some sociopolitical identification. The utility, though, does have the role of stimulating and supporting the cooperating individuals, and in some cases, appropriate sociopolitical locales overlap substantially with locales where peak demand reduction is desired for distribution reasons. In any event, distribution considerations could play a role in selecting targeted areas.

Community Electricity Management Program. A second conservation program that also appears well-suited for targeting is the Cooperative Electricity Management Program (CEMP) run by the Pacific Gas and Electric Company.

Created in 1979 to evaluate the feasibility of joint PGandE-community programs and to determine the response of customers to indirect incentives, CEMP explicitly recognizes and rewards load management measures administrated and carried out on a geographically differentiated basis. The program continues to be refined with experiments still being performed to best select participants and develop measurement techniques.

Under CEMP, PGandE establishes direct contact with a community-based committee representing citizens, businessmen and city government, which is then charged with developing and implementing a program to shift electricity usage away from the periods of summer peak demands. The utility company provides support in the form of guidance, an operational budget of $30,000 for each season, and financial incentives based on the percentage reduction in summer peak demands effected by the program. Currently, $10,000 is awarded to the committee for each one percent reduction in a normalized summer peak, compared to that of the previous summer up to a maximum of $100,000. The distribution of this reward is determined by the committee and is typically directed toward community-oriented projects.

During the first year of CEMP, three cities were selected for participation in a pilot program. Davis, Chico, and Merced were selected because of their location in the hot San Joaquin Valley, where the extensive use of air-conditioning results in high summer peaks, and because of their relative isolation from surrounding communities, which facilitated monitoring. Special metering arrangements were required to isolate the energy usage and peaks of the geographically defined communities. At the end of the summer, analysis of the data resulted in awarding the maximum program incentive to all three cities. The reductions in normalized peak load for Davis, Chico, and Merced were 22, 17, and 13 percent, respectively. These reductions in peak demands also yielded significant savings in energy; demands were not simply shifted in time, but reduced.

It is not possible, however, to ascribe all the credited reductions solely to the program. Although adjustments were made for the number of summer customers and weekdays, corrections were not included for changes in weather, nor for a change in the rate structure from flat to an inverted three tier (10).

The experiment in Davis is particularly illuminating. Self-selection could be responsible for the program's success; Davis prides itself on its reputation as a national leader in environmentally responsive programs. On the other hand, this disposition has already resulted in significant conservation measures, such that the program's effect may actually be understated. A statistical analysis of the program in Davis concluded that 42 percent of the reduction in peak demands could be directly attributed to the program (11). This success is further reinforced by the experience of another city, Eureka, successfully reducing its peak from already low levels.

From the standpoint of targeting, a more directed point is that the requirement of isolatability appears necessary. Excluding, for the moment, measurement costs, which may decrease with the use of computers to directly analyze billing information, a PGandE manager involved with the program notes that the isolation of the cities lends an air of community, which must play a major role in the program's success. This feature may not be present in other areas where such geographic divisions are not as obvious. Even within the participating communities, some resistance to the concept has been aired by commercial interests and the existence of a "free-rider" problem, where indirect participation in the benefits is not accompanied by direct participation in program requirements (10).

The effectiveness of this program and its ability to accommodate targeting criteria are a direct function of the ability of the joint committee to modify the energy-using behavior of its populace. This ability can be seen to lie in part with the sense of community spirit and identity that is lent by geographic separation from neighboring cities. Thus, while this approach may find limited application in areas with little locale-identification, e.g., the various cities in the Silicon Valley, its potential in more isolated communities could be substantial.

The relevance of this program as an experiment and its direct applicability to targeting for the purposes considered by this study are the same as that of the CCEMP, considered in the previous section.

Group Load Curtailment. Another example of a program that could be well-suited to a locale-specific demand management effort is PGandE's Group Load Curtailment planning. The concept, which was originally sponsored by the U.S. Department of Energy and begun in California at Southern California Edison and the Los Angeles Department of Water and Power, recognizes that the potential for reliable load shedding increases when the responsibility for curtailment is shared between economically similar customers. Joint responsibility, however, increases transaction costs and limits the composition of groups to businesses that are located near one another. The program remains in its infancy both with respect to its market penetration and to the outreach techniques employed.

The criteria used in establishing the groups requires that each member have a demand of greater than 1000 kW, of which at least 200 kW is curtailable, and that contact and coordination among members be easy. Groups are currently formed under PGandE direction, which proceeds from an analysis of billing information, business type, and geographic proximity, to direct solicitation of participants and initiation of group proceedings. It is left to group members to settle the necessary contractual relationships among themselves and to establish a liaison between the group and the utility. To date, several Group Load Curtailment arrangements have been formed in the PGandE territory.

In operation, PGandE notifies the group when there is a need to curtail. The assessment of need is based on a morning forecast of the spinning reserve to be available and required that day. Successful curtailment is determined by the group's aggregated reduction adding up to a total equivalent to each having shed

200 kW. In this way shared responsibility is encouraged; other members can cover the un-met commitment of a partner.

The incentive is a combination of fixed and variable payments calculated from participation in the program, and the number and degree of successful curtailments. Bonuses are awarded for exceeding the requested curtailment level. Failure to meet a request does not incur a direct penalty. Rather, temporary upward adjustment is made in the group's minimum service level that will result in smaller benefits from future curtailments until several subsequent curtailments are successfully met. The payments are made to the group as a whole. Based on preliminary results, PGandE personnel estimate that this may be one of its most cost-effective load management programs (12).

There are currently more potential participants than PGandE has the manpower to coordinate, which suggests a need to set priorities. This fact, coupled with PGandE's desire to expand program operations to the Silicon Valley, could yield large savings in avoided costs for distribution reinforcement.

Further, exploiting previously established business ties arising from local associations can surely lessen the transaction costs borne by the utility and the participants in group formation and coordination. Such costs are apparently a major obstacle to the expansion of the program and have limited the number in newer groups. This reduction in size, in turn, affects the ability of group members to "carry" the reductions expected of others. Indeed, discussions have been initiated to extend the concept to individual curtailable rates for power.

Experience with the Group Load Curtailment program is limited and the industry is low on the learning curve. Substantial improvement in efficiencies are anticipated.

The programs are certainly targetable geographically by the utility. Since they must be initiated and organized by the utility, the program is already substantially targeted. Only a distribution system based criterion need be added to the existing selection process.

A utility cannot, of course, request a group to curtail their load frequently. A curtailment request would be appropriate only when quite unusual demands were placed upon the substation set. This restriction does not, however, seriously limit the effectiveness of the Group Load Curtailment program as a means of targeting load management. Substations must be designed to accept unusual loads, and any reduction in the degree of this requirement would reduce reinforcement expenditures.

Load Management Planning for Large Commercial and Industrial Customers. Another type of program that could be applicable on a geographically targeted basis involves direct utility conservation and load management assistance to large commercial and industrial customers. The California Energy Commission's Non-Residential Load Management Standards require that electric utilities contact all commercial and industrial customers to provide reliable and consistent conservation and load management assistance. Using 1979 as a base year, these programs are directed to effect a 20 percent improvement in energy efficiency by 1985 (13).

In response to this order, the Southern California Edison Company (SCE) has developed a program that is exemplary in both its structure and its relationship to targeting considerations. The market for such programs remains far from saturated. Of the 840 large commercial and industrial customers (500 kW) in the SCE service area, only 70 audits had been performed by the end of 1981 (14).

In an effort to contact customers with a high potential for savings SCE has developed a ranking methodology based upon customer load-factors (kWh/kW). According to this methodology, customers with high demands relative to energy use are given first priority, followed by those with high energy use but lower demands.

The program is structured around a series of increasing incentives triggered by demonstrations of customer commitment. Initially, a generalized audit is offered reviewing the major energy-using appliances of a facility (HVAC, lighting, and water heating). At the next level, SCE offers to provide technical assistance in the form of engineering expertise for measures requiring in-depth analysis. At the request of the customer, SCE will pay for half the cost of a technical audit performed by an outside engineering firm (up to $5000), in lieu of using in-house (to SCE) help. Finally, the utility can offer direct financial incentives for projects with payback periods of greater than two years. The current level of these payments is either $0.03 per annualized kWh saved or $35.00 for each kW of demand reduced. The determination of the payments is based on actual billing information from before and after the implementation period.

Despite the program's relative infancy, considerable experience has been gained in the area of program operation. Insight into the factors that motivate large customers have been incorporated into the programs. The triggering sequences of services offered is an example of this learning process, as is the present form of the financial incentives. More importantly, it has been recognized that, in order to achieve savings, the services offered by the utility must be long term in nature. A symbolic gesture in this regard has been the renaming of programs as energy management services rather than simply commercial/industrial audit programs, the original name suggesting a much shorter term relationship with the customer.

The large number of un-audited customers and apparent budgetary/manpower constraints suggests that the overlaying of geographic considerations on a scheme that already ranks customers with high demands, could be effective. The direct costs of such a modification appear to be small since the basic mechanism is already in place.

One further benefit could result from the targeting effort. The initiation of contact through local and other business affilations has proved to be a highly effective means for recruitment and would be a logical candidate for use as an outreach program employing targeting criteria. In a recent study examining the failure of Zero Interest Loan Programs to attract significant numbers of low-income participants, it was concluded that the typically difficult-to-reach rental market could be reached through trade organizations (15). Indeed, the utilization of this technique resulted in the greatest degree of success of any of the outreach methods examined, including direct mailings, telephone conversations, contacts, and other mass media. This seems to validate the intuition that one is most directly influenced by the actions of one's peers. Targeting programs by geographic area could exploit this intuition with great benefit.

In summary, the SCE program for large customers effectively pursues its goals through relying on customer responses to trigger program steps and by recognizing the need for direct incentives to influence capital investment decisions. Given the manpower constraints of the program and institutional framework of this customer class, effectiveness could be enhanced by incorporating targeting criteria into existing methods of determining priority.

Load Management Planning for Small Commercial and Industrial Customers. The final program reviewed for its potential in a geographically targeted format parallels the previous one and is also managed by the SCE. The clients in this case are commercial or industrial customers with less than 500 kW demand.

The greatly increased number of eligible customers has necessitated a less elaborate program with respect to customer solicitation and audit production, but the financial incentives offered uniquely address the need to implement cost-effective measures. The nature of these incentives is well-suited for and could be improved by targeting criteria.

Customers are given priority on the basis of demands, which ranks them in three groups. There is no apparent priority within the tiers, but biases are evidenced across tiers by the level of audit services offered. Members of the largest class (200 - 499 kW) are contacted annually and offered an audit. For the middle tier (20 - 199 kW), this service is offered every two years. For the lowest tier (20 kW), contact is made through the mail. A response form can initiate a streamlined or computer-generated audit based on information supplied by the customer.

In addition to the audit services, two financial incentive programs are in place. Conservation Means Business successfully involves the members of the business community in on-going efforts to implement conservation and load management measures. Participation takes the form of incentives offered to contractors, HVAC and lighting equipment vendors in return for the installation of retrofits on their clients' premises. The merits of this type of involvement have also been cited in ZIP study, in which contractors, despite initial resistance from potential customers, became the most effective recruiters for the ZIP loans (15).

The second incentive program is similar to that available to large customers: direct payments are made for investments in conservation and load management measures. The nature of these payments has evolved from specific payments for particular measures to payments based on actual savings. An approved measure will receive $35.00 for each kW of demand reduction and $0.01 for every annualized kWh saved, up to a maximum of $5,000 for each meter or 50 percent of the customer's investment. A payback criterion (used to award large customers) is not required to trigger the payments to small customers, since the incentive to implement low cost measures is perceived as being less than that experienced by large customers.

In addition to the benefits of targeting listed for the large commercial program, the prospect of targeting the Conservation Means Business program will be highlighted. The need for on-going contact and reinforcement to customers, to achieve lasting demand and energy savings, could hardly be more well-served than by the contractors, installers, and salesmen who have a continuing and now added economic interest in assisting their customers.

The use of targeting criteria by this group is already taking place implicitly as a business necessity. More explicit rendering of program goals should only stimulate these efforts.

The geographical targeting of this program would, in many ways, be similar to that of the program for the larger customers. However, these customers apparently perceive the savings as warranting less attention than do the larger customers. The resulting hesitancy to introduce demand-reducing measures can work both ways. Their response will be strongly influenced by the effort level of utility personnel, which could be scaled to effect demand control in a particular locale. On the other hand, there are diseconomies of scale in this program, and much of the promotion depends on the efforts of non-utility personnel. A careful assessment, and perhaps some experimentation, would be required to determine whether this program is the most effective means of introducing geographical targeting criteria.

Projecting the Effectiveness and Impacts of Targeted Conservation and Load Management Programs

Earlier sections described some existing conservation and load management programs and the possible addition of geographical criteria for assigning priorities and personnel effort. Two general questions will now be considered: How effective would increased effort be in reducing demand growth in a locale? And, what effect would the concentration of effort in some locales (at the expense of effort in others) have on the systemwide demand growth reduction effort? These questions cannot be answered with precision or with great confidence. The same situations exist with respect to the larger questions crucial to most conservation and load management planning and implementation. In the face of uncertainty, we can only elucidate the issues involved.

Projecting Conservation and Load Management Program Effectiveness. Projecting conservation and load management program penetration is difficult at best. As pointed out by PGandE's J. E. Brennan (8),

> ". . . The current estimation process is not capable of performing "scenarios" or "what-if" analyses, e.g., "What revised penetration rate would be applicable if PGandE were to increase its conservation incentive to the customers by a factor of two?" or "What penetration rate would occur if energy prices were to rise by 100 percent in three years?" There is a need for developing a "quick turn-around" planning tool(s) which can be used to estimate conservation penetration under various assumptions."

Compounding the problem is the difficulty of actually knowing what the impact of an existing conservation or load management program really is. Ahmad Faruqui's "EPRI Perspective" (in EPRI EA-2496) indicates that the Workshop identified four main problems relating to measuring the effectiveness of residential conservation programs (8). These are:

1. Doublecounting. How is it possible to isolate the effects of conservation programs on customer electricity use from the effects of weather, price, income, and other "casual" variables (e.g., other programs)?

2. Self-selection. Consumers who volunteer for conservation programs may be "different" from the average customer.

3. Rebound. Program-induced changes in thermal integrity may not yield savings in direct proportion to the increased thermal integrity because the household may also change its thermostat setting to get increased comfort.

4. Aggregation. Diversity across customers in appliance holding, discount rates, etc., may make it difficult to extrapolate results from a sample of customers to the service area population.

A comparable problem exists in evaluating the effectiveness of other types of conservation and load management programs. For example, DOE is now sponsoring an assessment of the Institutional Conservation Program (commonly referred to as the Schools and Hospital Program). Consultants are reviewing the energy conservation technical analysis for buildings in ten states, and then visiting the buildings to determine actual performance after the energy conservation and load management measures recommended have been implemented.

Preliminary results from this program assessment show a highly varied set of energy savings performance (16). One of the best projects achieved a 75 percent savings, yet others actually increased consumption after participating in the program, with increases that could not be attributed to unusual conditions or growth. These studies also revealed the difficulty in accurately predicting levels of conservation and load management for a particular installation. In one case a prediction of savings of 44 percent resulted in only 27 percent actual savings. In another, a 10 percent prediction turned out to be 30 percent in actuality.

Fortunately, in assessing the effectiveness of targeting a conservation or load management program, one does not need to address these difficult questions. For a program that has been operating and is judged worthwhile to continue, one has actual data upon which to justify its effectiveness. In considering the application of targeting criteria, one will, initially, deal only with such successful programs. The question that then needs to be addressed is whether an increased effort in one locale will produce results that offset any consequent adverse effect in other locales, and thus not decrease the effectiveness of the program overall.

<u>The Impact of Targeting on Overall Conservation and Load Management Program Effectiveness</u>. Against this backdrop of uncertainty concerning the actual effectiveness of conservation and load management programs and measures, a key concern is whether targeting such programs geographically would reduce the effectiveness of the programs on systemwide reductions in either total energy demand or peak demand. This question can only be addressed on a case by case basis.

In general, the response to program efforts depends on the level of effort already undertaken; a typical effort-response curve has a sigmoidal shape as is shown in Figure 12. The low or "acceleration" region of the curve is representative of what happens when a program is first initiated or is diffuse. In this region, response is small since the best methods for seeking respondees have not yet been fully developed. Extra effort in the acceleration region produces more than proportionate results. Often, a program at this level does not yet have the benefit of a most important tool in seeking respondees--the word-of-mouth advertising from neighbors or associates (residential, commercial, or industrial) who have responded and found the program beneficial. The central or "linear" region of the curve represents an ongoing program which enjoys this benefit and where false starts inherent in any new or small program have already been overcome. The upper portion of the curve represents the area in a program's development where "saturation" has occurred. Program effectiveness slows down because prior efforts have

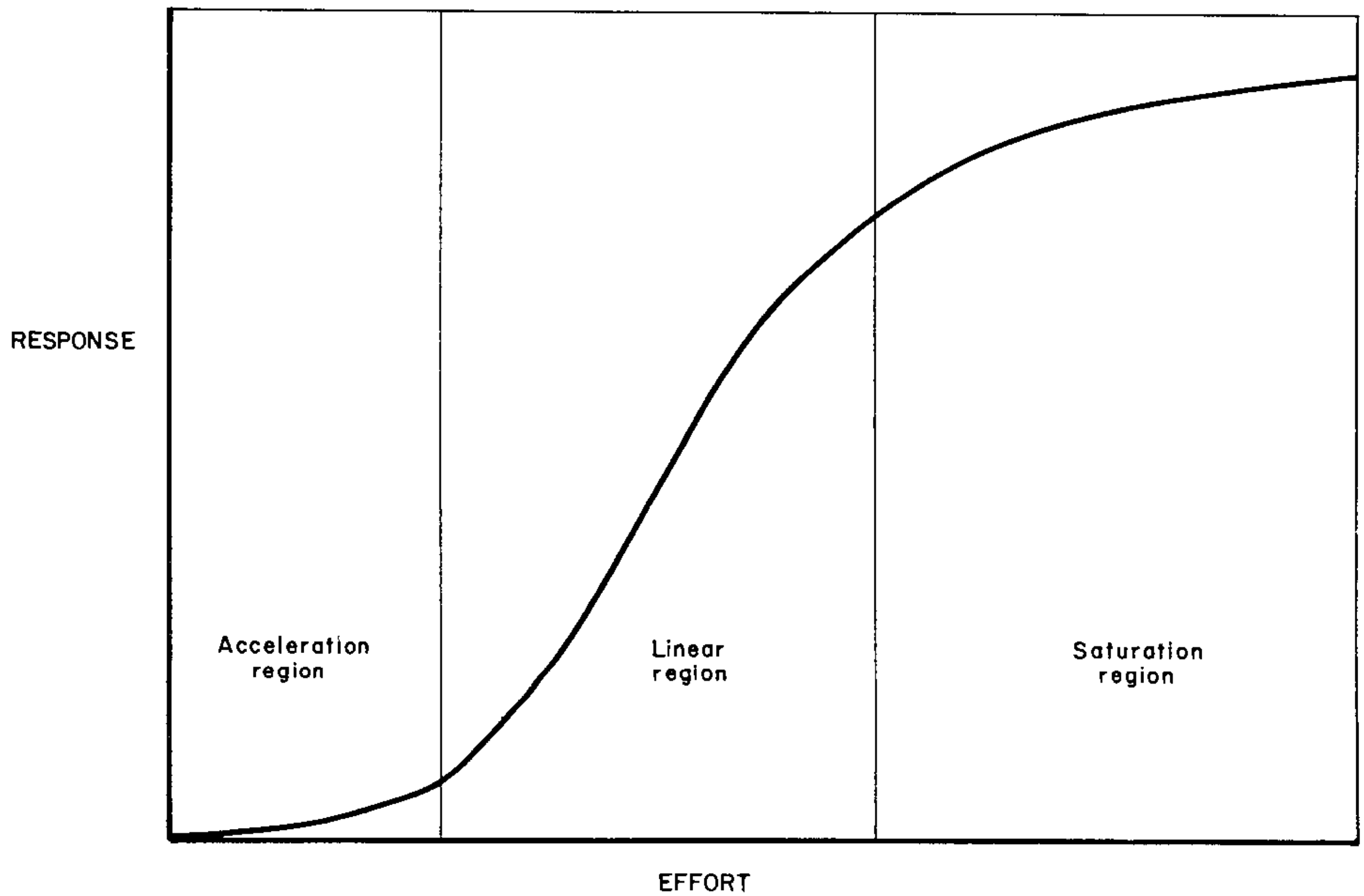

Figure 12. Effort/Response Curve

already captured most of the benefit. More intense effort produces less than proportionate response.

An increasingly important reason for saturation, the significance of which can vary greatly from one locale to another, is that new construction or newly added energy-using processes tend to be very efficient because of increasing energy costs. Conservation programs may, consequently, have little effect on such users. Awareness of conservation potential varies substantially from one industry to another, but is likely to become universal.

For programs situated in any of the three regions (acceleration, linear, or saturation) one can now consider the effect of targeting on the total system. Two assumptions are made: that the response curves for the targeted areas have the same form as those for the system as a whole, and that the effort is totally targetable. Both of these are good approximations, and it is not difficult to modify the considerations when different conditions apply. For simplicity, we examine only situations where increased effort in the targeted regions is matched by decreased effort in other areas; the entire system effort for the program is constant.

Consider first a program in the linear region, where equal increments of effort produce equal increments of response. In this case, for changes of effort that keep all locales within the linear region, no change in overall system response is caused by the targeting. The analogous situation for programs in the saturation region will cause a decrease in total system response, while for programs in the acceleration region this targeting would result in an increase in systemwide response. Many other effort/response situations can be analyzed, two in particular.

The first concerns a program operating in the linear region. A small fraction of the service area is targeted for a large increase in effort, which brings that area into the saturation region. This would create a decrease in total system response which would have to be justified by savings on the distribution side. The second case also concerns a program operating in the linear region. Here, targeting slightly increases the effort in much of the area at the expense of a large decrease in some smaller area where distribution facilities are underutilized. Such targeting does not produce any striking savings in distribution expenditures. However, to the extent that the acceleration region is substantial, targeting would produce an actual increase in system response to the conservation program.

Clearly, different conservation and load management programs will have different effort-response curves, but in general, each will exhibit a somewhat similar shape. Thus, analyzing what has already been done in the locale for which targeting is contemplated together with knowing what is possible in a given locale (based on prior program experience either in the utility or in general) should reduce the uncertainties surrounding a program's impact.

DISCUSSIONS WITH THE CONSERVATION AND LOAD MANAGEMENT PERSONNEL OF A PGandE OPERATING DIVISION ON LOCALLY CONTROLLING DEMAND GROWTH

The feasibility of geographical targeting will depend critically on the mechanisms for the implementation of conservation and load management programs. In a large utility, such as PGandE, this implementation, including the crucial selection of conservation client candidates, is done in the operating divisions. Therefore, we now report on information gained from PGandE conservation and load management personnel whose responsibility includes the Cupertino area described in Section 3.

Discussions were held with three people at different management levels in PGandE's San Jose Division (marketing supervisor, energy conservation supervisor, and energy services supervisor). The lowest level of these supervises nine energy management teams.

Discussions covered topics to be treated in the following order: Present selection and follow-up criteria for prospective clients, program effectiveness and predictability, the question of "saturation," time scale, information needed to add distribution-based geographical targeting criteria and problems anticipated, and comments on a particular interaction mechanism suggested for targeting. The treatment here is not intended to be comprehensive or definitive.

Rather, we wish to present a preliminary indication of one present situation and its implications for distribution-based targeting criteria.

<u>Present selection and follow-up criteria for prospective conservation clients</u>: Currently, distribution-based criteria are used. There is an emphasis on the large customer (over 500,000 kWh/yr). Load factor is not much of a criterion since most of the load factors here are high, with 70% typical for some months.

Therefore, addressing kWh savings also addresses peak load reduction. Conservation teams are distributed roughly in proportion to the number of large customers in the area. Selection is also based on "conservation potential," deduced in part from studies of companies by SIC code.

An attempt is made to reach the "decision makers" in the customer organizations. Follow-up efforts are based on commitments from such people and having such commitments demonstrated by some action. A "sales type" mode is considered the most effective. Conservation has to be sold as items such as office copiers are sold. (There was strong agreement with: "If it's not sold, it won't be bought.")

Conservation teams are assigned specific kWh and kW savings goals. Meeting goals is documented by among other factors, comparing customer billing pre- and post-audit. Individuals receive ratings on such bases. In assigning goals and ratings, it is understood that some teams have more difficult areas (e.g., the large customers being widely dispersed).

Thus, the criteria used to choose and pursue candidates for conservation activity are often explicit and objective, but include important implicit and subjective aspects. The actual mode of furthering conservation is closer to that of selling by a private, unregulated corporation, and it contrasts with the more strictly prescribed procedures used by many utility operations.

<u>Effectiveness and predictability of conservation programs</u>: Despite the difficulty of separating the effect of conservation activity from the impact of increasing electricity costs and fluctuations in the economy, experts in the field can usually give reasonable estimates in a <u>particular</u> situation for what can be accomplished and the time involved.

An example: For the Cupertino area, roughly defined, there is approximately 500 MW of demand, of which 75 to 80 MW are considered by the conservation managers as "potentially conservable." They believe that approximately 5% of this, or 4 MW, could be achieved by the conservation programs in a given year.

When the programs involve cash incentives, the effectiveness is greatly enhanced and quite predictable. In addition, new industrial growth often builds in conservation for self-recognized economic reasons and warrants little attention from conservation programs. The extent of this, however, can vary widely by industry; some are more energy conscious than others.

The question of "saturation:" A discussion with San Jose Division conservation personnel on "saturation" (as outlined in the last subsection) showed that it is difficult to say generally where programs are on an effort response curve. Specific cases can be treated to some extent. For example, the low degree of saturation in the Cupertino area could be implied by the fact that only 5% of the "potential conservation" is presumed attainable each year. However, the expansion of the 500 MW base through new construction in the area will have a smaller potentially conservable proportion. Saturation may well be an important consideration for targeting programs in the longer term. Some time ago, it was thought that major conservation goals would be achieved by 1985, but today 1990 seems a more reasonable date. In some special industrial sectors, where conservation attitudes are particularly advanced, the saturation region of the effort response curve may be entered in two or three years. In other cases programs may still be in the acceleration region.

These views of sophisticated managers, who are on the implementation firing line, are consistent with the more general statements heard at corporate headquarters and read in the published literature. Forced to make decisions in the face of such uncertainty, the best assessment would be that programs are most likely in the linear region, where modest changes in effort produce proportional changes in response.

It should be noted that we are using as an example in this discussion a utility with a long and intensive pursuit of conservation and load management, and that we are talking with a division known for particular sophistication and success. Saturation is more likely to be a limit here than in other utilities and regions where conservation programs are less mature.

Time scale: If a conservation or load management program is to result in actual KW savings, one must know the time scales, particularly if the program will be used as the basis for (even tentatively) postponing distribution reinforcements. However, this is a difficult question. Part of the problem is inadequate experience; most programs have not been constrained or even planned to have their total, or even major impact on a particular time schedule. Activity that results in savings in a few years is considered quite valuable.

If capital investment by the customer is required, conservation spending may be postponed until the following year's budget. In such cases, years may elapse between the first contact with the conservation team and the actual energy savings. On the other hand, with incentive programs, where cash payments are offered for conversion to more efficient equipment, results can occur within a month. One can anticipate a noticeable effect within two months, sizable within six months, and the program will reach its full steady state effect within two years.

Consequently, the time scale for an overall demand management effort in an area would be influenced by particular conservation and load management programs. Time and effort would also be effected by taking time scale of action into account.

Information needed to add distribution-based, geographical targeting criteria and problems anticipated: These conservation managers felt that both questions could be easily addressed. The only information needed was that necessary to reorganize the goal structure for the conservation teams. If it were decided that kW savings in a certain area were, say, twice as valuable as kW savings in the rest of the division, it would only be necessary to inform the divisional conservation managers. There appeared little doubt that this would result in significant concentration of effort and results as the teams were assigned new evaluation criteria. They felt that the complexities of responding to such information would not be much greater than those they now face.

It was also felt that new problems with clients created by the introduction of geographical criteria would not be significant. From the customer's point of view, these criteria are not substantially different in impact from those already being applied, i.e., customer kW demand, a somewhat coarse assessment of conservation potential, and an often subjective judgment of commitment. Customers for the most part would not even be aware of the criteria, even though no attempt to keep them secret would be made. Customers whom the criteria de-emphasized, but who requested participation in a program, would be treated the same as emphasized customers. Since adoption of conservation and load management measures depends so much on active salesmanship directed at individual companies, adding this small number of "volunteers" would not seriously affect the geographic targeting.

Comments on a particular interaction mechanism for targeting: In an earlier subsection we suggested a specific mechanism to enable expedient interaction between distribution planners and conservation managers. From the conservation managers, this required an examination of a locale's peak load projections in light of how geographic targeting of the existing conservation and load management efforts would revise them.

Divisional personnel felt that conservation managers could accomplish this. The accuracy of their predicted effectiveness of conservation effort would vary with specific locale and the conservation and load management programs contemplated. Their accuracy would probably not be substantially worse than the original projections with which the distribution planners were initially working. Personnel viewed the conservation management role outlined here to be feasible.

A final note on discussions with operating division personnel: A conservation targeting criterion with the reduction of capital expenditures as its principal motiviation was welcomed by operating division conservation personnel. They recognized that such activity could improve the way their work is regarded within the corporation.

SUMMARY OF THE EFFECTIVENESS OF TARGETING CONSERVATION AND LOAD MANAGEMENT PROGRAMS BY LOCALE FOR CONTROLLING LOCAL PEAK DEMAND GROWTH

The effectiveness of targeting conservation and load management programs by locales is a function of the following: 1) the external constraints to the application of the concept; 2) the internal constraints to incorporating the concept within the utility; and 3) the range of programs available with the attendant effect of targeting upon systemwide goals. Analyses of these items indicates that targeting conservation and load management programs by locales is feasible. (The analysis in Section 3 indicated that capital expenditure deferrals of a few million dollars for a few years are possible with effective targeting programs.)

The external constraints imposed through legal mandates and regulatory requirements on geographically targeting conservation and load management programs do not usually differ from those for non-targeted programs. Public and political concerns appear to have lessened over possible equity issues with respect to specific conservation and load management programs, when such programs, *in toto* are perceived as equitable. Further, the targeting of concern here is intended to accrue additional benefits at essentially no additional cost to any ratepayers through cost avoidance associated with reducing or deferring the need for substation reinforcement; this would benefit all ratepayers. Thus, while equity issues should be kept in mind as targeting efforts are developed, they need not prevent the approach from being used.

Implementing a geographical targeting program by the utility, like implementing any new approach, will of necessity change the working relationships of the personnel involved. Our analysis suggests that the targeting approach can be implemented in a way that would not be disruptive and would be welcomed by most of those involved. Distribution system planners would gain additional flexibility in making substation reinforcement decisions, and conservation and load management people could see a direct benefit to the utility.

Since the time scale for implementing conservation and load management programs is frequently consistent with the planning horizon of the distribution planner, it should be easy for the distribution planners to incorporate the results of a targeted program into their projections. Additionally, the targeting approach can be introduced gradually, thus permitting the process to be evaluated and modified prior to wide application.

The examination of a few utility conservation and load management programs indicates that a variety of them are suited to geographic targeting. In some, modifications in detailed approaches would enhance their effectiveness with regard to the local peak problem considered here, but this would have to be assessed in light of possible effects on the conservation and load management program's other goals.

Presumably, only conservation and load management programs that have been judged successful will be targeted. A crucial question then becomes whether targeting might adversely (or beneficially) impact these programs' primary goals of system-wide reductions in energy use and peak demand. There is no simple answer, but a critical indication would be a change in response rate following a change in the amount of conservation effort expended.

Finally, in discussions with the conservation and load management personnel responsible for implementing programs within one of PGandE's locales previously studied from a distribution point of view, internal constraints to the initiation of a targeting effort were perceived to be minor. Indeed, the idea of targeting was warmly received.

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Section 5

REVIEW OF BENEFITS AND COSTS

Section 3 analyzed the potential advantages of distribution-based targeting of demand-side management programs. Section 4 considered how such DSM efforts would be feasible within the present framework of utility distribution and conservation/load management activities. Targeting can be applied to a wide range of locales, and the available mechanisms and the appropriate degrees of targeting vary even more. Moreover, reinforcement deferral times tend to be indefinite and non-quantifiable costs of targeting can be as significant as any others. Therefore, no generally meaningful "benefit/cost ratios" are possible. A calculation of the benefit of capacity deferral (or the costs of the effort) in terms of present value is not essential for the discussion, and the situations will actually be more transparent in terms of the amount of expenditure deferred and the cost of accomplishing the deferral.

BENEFITS

The analysis described in previous sections indicates that the principal economic benefit of geographically targeting conservation and load management programs is reduced capital requirements for substation reinforcement. This is achieved by reducing demand growth preferentially in those locales in which substation reinforcement will be required in the next few years. Demand growth in locales in which substation facilities are less impacted would be less aggressively addressed. A successful targeting program of this sort will increase the average utilization factor of substation equipment in the system.

Despite common utilization factors of 70% or lower, while other locales operate with utilization factors of over 90%, significant increases in the efficient utilization of this capital equipment may be possible. The average capital expenditure for substation equipment to meet demand growth is reduced in proportion to the fractional increase in average utilization factor. An even larger benefit can be the transient one that accrues during the shift of the system to higher average utilization factors. These points are detailed quantitatively in Section 3.

Any benefit gained in avoided costs in the overall system must be achieved by many activities on a locale-by-locale basis. The magnitude of these avoided costs will vary substantially from case to case depending on the nature of the equipment required and the cost of land, including rights of way for subtransmission feeders to substations. To present a realistic illustration, this section examines the Cupertino area of Pacific Gas and Electric's San Jose Division (discussed in Sections 3 and 4) as an example of a targeting possibility. The Cupertino locale, a largely light industrial area with substantial recent growth, has approximately 500 MW of demand with an annual growth rate of about 25 MW. The average utilization factor for substations in the locale is over 90%, and reinforcement is needed almost every year. Any reduction in demand will, therefore, show up almost immediately in a reduction of capital expenditures.

Conservation managers in the Division estimate that conservation and load management programs currently produce about a 4 MW annual demand reduction below what would exist without these efforts. Assuming that the programs are on a linear region of an effort/response curve, doubling the effort in the locale would produce another 4 MW reduction. This would reduce the needed reinforcement by 15%. At our previously estimated cost of $80/kVA for reinforcement, this would yield an annual deferral of capital expenditures of $320,000 in this locale. (The $80/kVA figure is probably low for the Cupertino area, where construction constraints and costs are high.)

Although estimates of capital expenditure deferral are approximate, they are the easiest targeting benefits to evaluate. A benefit that may well be more significant in the long run, as the ability to utilize it fully develops, is the increased flexibility accorded distribution planning. The description of the distribution planning process in Section 4 outlines the severe problem of making expensive and sometimes sensitive decisions in the face of substantial and unavoidable uncertainty in demand projections.

The targeting of conservation and load management efforts can, in principle, reduce this uncertainty substantially. While conservation and load management programs influence demand slightly in the short run, the effect can be a significant fraction of demand growth in the medium to long run. The time scale for many conservation and load management programs is short enough that targeting could be effectively used as a stand-by back-up mechanism for distribution planning assumptions. The development of an effective coupling between conservation and distribution planning could be held as a demonstration of management efficiency in the utility.

Conservation personnel would welcome as an addition to their activities an aspect more directly related to corporate financial benefit than is obvious (to many) in their usual endeavors. This was brought out in conversations with conservation managers at several administrative and corporate levels.

Another possible benefit of targeting conservation and load management programs is better evaluation of these programs. This benefit will be discussed in Section 6.

COSTS

The largest direct costs of geographical targeting would be those of establishing and funding new conservation or load management programs designed especially for targeting. While such programs might eventually be developed, none will be considered here. In this feasibility study, it is sufficient to show that existing programs can accomplish the desired results. It appears, in fact, that much of the available benefit can be captured by simply restructuring some of these program goals.

This is an important point. Almost no specifically assignable cost of the targeting program need exist. The important cost of targeting to "non-participants" could be identical to that of the non-targeted program, i.e., non-existent, if this is the regulatory criterion being applied.

The costs of introducing and continuing to administer geographical targeting in existing programs is the most identifiable cost of targeting, and can be estimated by the current expense for the updating and administration of conservation and load management programs. At the management level, where a targeting goal structure would be implemented and the results assessed, a reasonable organization usually has one manager for several teams of perhaps four people each. The teams themselves would perform essentially the same work as in the non-targeted situation. The cost of the present management time is a few percent of the cost of the conservation and load management personnel effort, and only a small fraction of what would be assignable to the targeting effort.

The human and fiscal cost of moving personnel from one locale to another to achieve targeting goals is worth considering, but can only be evaluated on a case-by-case basis. Since the size of the locales selected as targets will often be small compared to normal commuting distances, this cost could be small.

A less identifiable cost, but larger than the above management cost of implementation, would be that of determining the geographic targets and the desired degree of targeting from distribution substation data and other factors. This would include establishing a goal structure for the conservation and load management teams to achieve the desired results. In most utility organizations, this would require interaction at a headquarters level between distribution planners and DSM planners and managers. The choice of locations will often be quite clear. While it is difficult to make the optimal targeting choices, it is not necessary to do so in order to accrue substantial benefits. It is not easy to estimate the cost of management time and effort here, but it should not be large. If any substantial amount were spent it would probably be a result of a perceived benefit in the added flexibility in distribution planning made possible by targeting conservation and load management programs to control demand growth.

As mentioned above, interaction and communication between distribution planners and DSM planners is critical. Where this communication does not already exist, the establishment of new lines of communication often involves false starts and inefficiencies, particularly in stable administrative structures. Such communication problems are likely to be temporary and the interaction may ultimately carry some additional benefit.

Another possible cost of targeting would be a reduction in the systemwide effectiveness of conservation and load management programs resulting from geographical concentration. This would happen for programs in the saturation region of the effort-response curve of Section 4. Care should be taken to insure that this does not occur. The opposite effect, and improvement in systemwide performance, would occur for programs in the acceleration region of the effort-response curve. Sometimes, the degree of saturation of a program is not known. As discussed in Section 6, a small targeting effort could provide the information needed to determine the degree of saturation.

The most frequent reservation about geographical targeting of conservation and load management programs for the reduction of capital expenditure for distribution facilities is that targeting would raise objections from utility customers or regulators. To the extent that such objections are wide-spread and strong, the cost of the targeting programs would outweigh the limited benefits obtainable. This potential cost of a targeting program is serious enough that it needs to be addressed.

As described earlier, the mechanism envisioned for targeting is to add distribution-based geographical considerations to the already existing set of criteria by which candidate customers are selected and pursued for conservation and load management programs. Hence, even when targeting criteria are instituted, any customers, even those outside the target locale, could receive full advantage of any program by requesting participation. Only the intensive marketing efforts would be absent from customers outside the targeted locale. Under these conditions, there should be no significant customer objections. As to the question of whether such a "lenient" targeting effort would be effective, it is generally felt (see Section 4) that conservation and load management must be strongly marketed to be accepted.

The question of objections by regulators is also raised as an impediment. As discussed in Section 4, there are no explicit legal or regulatory prohibitions to targeting, *per se*. Further, the programs currently envisioned for targeting must already meet the generally accepted regulatory standards. Thus, there need not be any conflict with existing legal or regulatory requirements. Informal discussions with staff members of the California Public Utilities Commission confirmed that this would most likely be their attitude.

SUMMARY

The major benefit of geographical targeting is a reduction of capital expenditures for distribution substations. The maximum benefit obtainable is a small fraction of total distribution expenses, but nevertheless a substantial sum when compared with the effort needed to capture it. Care would be required in such a situation to ensure minimal disruption of other ongoing activities. It appears that this is feasible, and that the subsidiary benefits would outweigh the minor costs of any disruption.

Section 6

DESIGN OF A RESEARCH PROGRAM

Preliminary investigation in this study has indicated that a utility might achieve up to a several million dollar reduction in annual capital expenditures for distribution substations by the geographical targeting of conservation and load management programs. There is also a potential for small negative effects of such targeting. This section outlines a research program designed to develop techniques for accruing the maximum benefit with little or no negative aspects. This program will also develop some general rules to permit the rapid assessment of targeting possibilities. Further, a research program to develop targeting techniques will automatically evaluate conservation and load management efforts more generally.

It is evident that the benefits attainable from targeting can vary substantially from one utility to another and even more from one candidate targeting situation to another, even within a single utility. Studies of the effect of geographical targeting on an industry-wide basis would probably develop data with a degree of aggregation not useful at the level at which targeting programs would be implemented. Research is most appropriately directed at individual utility situations to design programs that pay off immediately at that level. Information and experience thus gained could then be collected and generalized for wider benefit.

The additional benefit accruable, while substantial in absolute terms, can be small when compared to the total cost of the programs to be targeted. The relevant cost for comparison, however, is the very small changes in those programs that are often all that are needed for effective targeting. There is almost no threshold of effort needed to effectively target an established program. It is easily possible, for example, to emphasize a particular program in a locale where a delay in the need for reinforcement of substation capacity is desired merely by adjusting the criteria for conservation and load management candidate selection. There are some very simple and safe, even profitable, experiments. The research proposed is, therefore, primarily a program in which targeting is actually done, evaluated, and improved.

There are three distinct issues:

- the selection of geographical locales to target
- the choice of a conservation or load management program and its means for implementation as the vehicle for the targeting
- The setting up of the targeting goals.

Selection of locales: The initial selection of candidate locales for targeting is done by the distribution planners, who supply a list of locales according to targeting possibilities, each with a specified reduction in projected growth rate that could lead to specified reductions in capital expenditures. There may well be some resistance in many distribution planning departments to being so explicit about projections, but some locales should be easy to identify, and only a few will be needed for the present purposes. Since this is a research endeavor, it will be interesting to determine what effort was needed to produce this information. The methodology which led to the results should also be reported. It should be emphasized to the distribution planning department that only rough estimates are required.

Choice of program and implementation: For each of the identified locales, the DSM program managers will consider already operating programs and then select a particular program(s) and the implementation mechanisms for targeting. This decision will be based on an assessment of the most effective program and mechanism for the locale and the time scale in question. It will also depend on the effort available (manpower, funds, etc.) for redistribution to the targeted locale from other locales where it is less needed. The program choice will also depend on where programs are thought to be on the effort-response curve (the degree of saturation). Again, because this is a research endeavor, the effort spent on this activity and the methodology employed should also be reported. It is unlikely that conservation and load management program managers will have much problem with these decisions.

Targeting goals: Setting targeting goals includes final decisions on the locales for targeting and must be at a level where capital expenditures, conservation and load management programs, and other factors can all be weighed. At this level, the relative importance of geographical locations for conservation and load management programs would be determined. This could be communicated to the program managers in the form of a stipulation that energy or peak demand savings in a given locale would be factored into the program evaluation as, say, fifty percent more valuable than savings elsewhere. The actual number would have to be adjusted (experimentally, perhaps) to achieve the proper result. Program managers would use such a number to develop explicit performance goals for their field teams.

After one year, the effect of targeting on the demand growth rate would be assessed by comparison to untargeted areas of similar customer character. The value of deferring capital expenditures could then be compared with whatever extra effort or expenditure the targeting required. Such an overview assessment would be done best from a position outside either distribution planning or the conservation/load management operation. Should the results be positive, the program can be intensified and incorporate the improved techniques that were suggested in the pilot stage.

What we have described is far from a full scale targeting program in which the relative desirability of demand growth reduction in all locales would be developed, and an optimum demand management program incorporating such information mounted. It is not yet clear how far along this path it pays to go. The answer will vary from one utility to another, and is best determined by instituting the process gradually as described here in the form of a research program. It should be noted that, in addition to being a program for the evaluation of targeting, what has been outlined is simultaneously a training program in its implementation. At any time, however, the acceleration of the program could be stopped, reversed, or the program completely abandoned with little loss or disruption.

There is an additional substantial research result from the institution of a targeting program -- the opportunity to assess conservation and load management programs in <u>general</u>. As pointed out in Section 4, assessing the effectiveness of conservation and load management efforts is hampered by the inability to separate the results of such efforts from what would have happened without it. Electric rate increases and economic downturns can have the same effects, for example. To assess a conservation or load management effort correctly, any change in the demand of the set of customers addressed by the program must be compared with the demand of a set of "controls." The controls must be customers with essentially the same characteristics from the conservation or load management program perspective, but who were not addressed (or were less strongly addressed) by the program.

Geographical targeting can provide just such a set of controls. In many cases, there will be little systematic difference between the set of customers in locales approaching a requirement for substation reinforcement, and the set in locales with substantial reserve substation capacity. In fact, after a reinforcement, customers unwittingly often shift from the first set to the second.

Therefore, by studying the effects of targeting a conservation or load management program on the actual demand growth in the targeted locales, and comparing this to otherwise comparable but untargeted locales, the programs' effectiveness can be assessed. The effect of rate changes, economic climate, etc., are automatically cancelled out. Such studies could give particularly good information on the degree of saturation of the programs. Such research on conservation and load management programs might even be pushed in its own right with targeting to reduce capital expenditure as an added positive factor.

The research program for targeting described above was on a small scale within individual utilities. As these individual activities are locally evaluated and the techniques for targeting are improved, we may accumulate enough experience to collect such data for general use. A small conference might possibly be warranted, but a brief report by an appropriate consultant might be more efficient, since the relevant information might not be within the purview of a single individual that the utility engaged in the targeting process. It would probably be a very small part of the backgrounds of several people.

When the profitability of targeting has been demonstrated, it will be appropriate to design certain conservation and load management programs suitable for targeting. Some now exist almost in this form, the Group Load Curtailment programs described in Section 4, for example, could be modified to be an ideal example. It would also be appropriate to monitor advances in electronic communications equipment that would be useful in such activities.

Finally, utilities might individually research and share the findings of how they can capture best the benefits gained by deferring capital expenditures through targeting. This would include both financial and good will benefits brought about by more efficient operation.