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Least-Cost Planning for Pacific Gas & Electric STAGE 2: Case Studies

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Least-Cost Planning for Pacific Gas & Electric

STAGE 2: Case Studies

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EXECUTIVE SUMMARY

The aim of this project is to demonstrate the usefulness of mainframe electric utility planning models for Least-Cost Planning (LCP). The essence of LCP is to evenhandedly compare sets of policy instruments on both the supply- and demand-sides of the company and choose that set that provides electricity services along a forecast least-cost trajectory. In practice, planning for complex utility systems is difficult and rigorously comparing among sets of policy options is beyond the current state of the art. In this study, a standard planning model, the Load Management Strategy Testing Model (LMSTM) is used to attempt some elementary LCP. LMSTM, which was developed by Decision Focus Inc. and the Electric Power Research Institute, is a chronological simulation model that estimates system loads using 16 typical daytypes and dispatches resources accordingly from an aggregated level producing detailed resource use and cost forecasts for up to 25 years ahead.

Two *a priori* viable demand-side programs, a commercial partial thermal energy storage program (TES) and an efficient residential air conditioning program (RAC), are traded off against a supply-side alternative of refurbishing aged oil steam units. Deciding which is the marginal supply-side resource against which demand-side policy initiatives should be measured is more troublesome question than it appears. Most analysis of demand-side programs in the literature have either assumed that the effect of the program is so small that a *ceteris paribus* assumption holds on the supply-side, or have compared the effect of the program to a clearly identifiable generation addition, usually a known planned new plant or a ficticious proxy based on the characteristics of a gas turbine. In the real PG&E world, no obvious large capacity addition is planned for the near future and much of the small capacity additions expected on the system are controlled by independent power producers or by municipal utilities. In this situation, the deferral of oil plant refurbishment becomes the marginal capacity addition. Immediately putting LCP into practice hits some obstacles because information on the costs and consequences of refurbishments is harder to come by than similar data on new plants, and the option is generally less controversial than new plant construction. In the absence of good data on oil plant refurbishment, this study resorts to a combustion turbine proxy as the margin supply-side resource.

The maximum peak saving effect of TES is estimated by means of a simple market penetration calculation carried out exogenously to LMSTM. The energy use ratio inputs to LMSTM are estimated using the DOE-2.1 building energy simulation model for five weather sites representative of the PG&E service territory. Energy use effects for all sites are aggregated to the system level with an appropriate split across the daytypes. The load impacts are estimated on the basis of simple operations assumptions and the operating objective of maximizing the afternoon load shift. It results in an estimate of 200 MW of load reduction at the absolute peak in 1996, and the program is assumed to end at that date. This peak reduction is smaller than one might expect because the system becomes stretched on the hottest daytype and uses some of its stored coolth to meet morning loads with the result that afternoon cooling relies more heavily on direct cooling than it does on normal summer days. TES tends to build evening loads when ice is being manufactured and, consequentely, marginal costs can be raised and the net effect on the system is not easily assessed. Valuing the change in system operations also depends heavily on the revenue loss that the fall in on-peak sales causes. Customers are assumed to be on one of the PG&E E-20 tariff options. This option features a time-of-use rate with a stiff demand charge. This tariff structure is currently compulsory for large PG&E customers that cannot accept interrupts.

Estimating the load saving is highly dependent on the number hours over which the estimates of load reduction are averaged. The top 150 load hours capture the overwhelming majority of LOLP on the PG&E system, and is used as the rule of thumb definition of the planning peak for the purposes of this study. Using a program written for this study the load reduction is averaged over 150 hours, yielding an estimated capacity savings of 174 MW. The value of this capacity is calculated by two methods. In method 1, a dollar value is placed on the incremental capacity reduction each year, and the net present value of the stream calculated. This is an overnight capital cost approach in which none of the capital carrying costs are considered. In method 2, the difference between the revenue requirements stream output by LMSTM is used as a source of an estimate of the value of the capacity benefit. The effect of the TES policy on the fuel mix shows the benefit of the load shifting as less expensive generation, notably nuclear, is substituted for oil and gas, with a corresponding drop in total annual variable operating cost. That is, the benefit of using cheaper fuel exceeds the extra consumption because of the operating losses of the TES equipment. Average marginal costs, however, are increased as the increase in marginal cost during the off-peak hours outweighs the on-peak fall.

A cost-benefit analysis finds the TES program generates positive societal benefits under both methods 1 and 2, but the utility loses under the primary and two sensitivity scenarios. The result for the utility, however, rests on the assumption that rate structures remain frozen, an unlikely circumstance in the long run. The high societal benefit of the program and its capture by customers suggest that TES is a viable technology and needs no incentives by PG&E to encourage customer adoption.

The second demand-side program considered is a tight efficiency standard for residential air conditioning. This case assumes that a standard is imposed exogenously for room and central air conditioners and heat pumps, and the consequences for the PG&E system are estimated. The imposed standard raises the minimum EER of room air conditioners from 8.7 to 9.0 in 1989 and to 9.5 in 1993, and the California planned minimum SEER for for central air conditioners and heat pumps of 8.9 in 1989 and 9.9 in 1993 tightens to 10.0 and 13.0, respectively. The effect of the standard on residential energy use and on system loads is estimated using the Lawrence Berkeley Laboratory Residential Energy Model (LBL-REM). This approach is very data intensive and relies heavily on prior work by LBL on the PG&E system. The PG&E service territory is simulated in four subregions, roughly corresponding to the former rate regions R, S, T, and X. No attempt is made to account for the effect of SMUD or the remainder of the PG&E territory. This simplification is necessary to limit the data requirements of the study. The cost of the simplification is unknown.

The residential air conditioning policy case results in a sales loss of 260 GWh per year by 2003, and a peak reduction of 415 MW. The effect is very concentrated near the peak, however, and estimates of the avoided capacity is highly sensitive to the number of hours over which the saving is averaged. Averaging over the rule-of-thumb 150 hours produces a capacity saving in 2003 of 275 MW. In fact, the capacity saving plotted against hours of averaging exhibits a strong log linear relationship. The highly concentrated nature of the load reduction results in a reduction in oil and gas use and a decline in purchases, but small changes in the use of other resources.

The cost-benefit analysis is best considered to a time horizon of 2014 in this case because that is the year in which the average efficient equipment bought under the program will be retired. Using this horizon, the program yields negative societal benefits under both method 1 and method 2. The considerable variable operating cost saving of 186 M$ and the capacity benefit is overwhelmed by the huge customer cost of the efficient appliances, over 338 M$. Since this cost is wholely borne by the customers under the assumptions used, the utility benefits considerably while customers lose. A brief review of the literature shows that even the 338 M$ is a low estimate of the the probable customer cost and, conseqently, the failure of this program to pass this simple cost-benefit test proves a robust result. The only sensitivity carried out that could yield a convincing case in favor of the program is a high cost oil case. Since the benefits of the program are derived primarily from oil and gas savings, doubling the expected price of oil in 1996, from the base case assumption of about 20 $/barrel, generates a net benefit of almost 100 M$ under method 1. However, even this benefit would be wiped out by a customer cost of equipment closer to the central estimate of costs found in the literature.

This work closes a two-year effort by LBL to do real world LCP using LMSTM and other computer models. The lessons of the exercise have been many, but the remaining problems are daunting. Modeling a utility system with the degree of precision necessary to evaluate and compare policy initiatives of the magnitudes discussed here is a tedious process and involves numerous compromises and simplifying assumptions that imply state-of-the-art LCP methodology and tools are still far short of the LCP ideal. However, under reasonable assumptions, it was shown that a comprehensive analysis of two demand-side programs is possible.

I. INTRODUCTION

This project is an attempt to evaluate the usefulness of mainframe electric utility planning models for conducting least-cost planning (LCP). In the project's first stage, the Load Management Strategy Testing Model (LMSTM), written by Decision Focus, Inc. (DFI) for the Electric Power Research Institute (EPRI) (DFI, 1982, 1984, 1985), was calibrated to the Pacific Gas and Electric Company (PG&E) system. The calibration attempted to replicate PG&E as portrayed in the company's 1985 Long Term Plan (LTP) (Kahn *et al.*, 1987), in the company's previous LMSTM input files, and in other data sources provided by PG&E. The attraction of LMSTM rests on its being an integrated model that attempts to solve the whole planning problem simultaneously. Only if the whole system is modeled as one organic entity can perturbations on opposite sides of the planning problem be compared. The stage 1 report describes the LMSTM calibration process in detail and discusses many of the issues and problems involved in LCP. In this, the second stage of the project, the stage 1 calibration is updated to incorporate more recent company information. This modified calibration is used as the ''base case'' against which some modest test cases are evaluated using LMSTM and other computer models, which solve parts of the problem exogenously to LMSTM.

True LCP would require that all feasible policy options were tested and compared. The policy bundle that delivered the lowest cost trajectory to an infinite time horizon would be selected and executed. The current state of knowledge and model capability is, however, far short of this ideal. At present, the only practical planning strategy is the repeated analysis of trade-offs between various supply and demand-side programs, and, more interestingly, between alternatives on the supply and demand-sides of the planning problem. Here the first steps towards LCP are taken in the form of a comparative analysis of two demand-side options which are traded-off against equivalent supply-side options, as embodied in the company's generation plan.

The two technologies considered as potential demand-side programs are thermal energy storage (TES) for commercial air conditioning systems, and efficient residential air conditioning (RAC). TES is an emergent technology about which rather little literature based on practical experience is available. It is, nonetheless, a promising load management strategy and is already the target of a PG&E incentive program. The principle of TES involves reducing the peak cooling load of a building by relying on melting ice to supplement the air conditioner chiller at hot times. TES reduces peak loads because the chiller needed to meet peak cooling is smaller, and generates some load building at off-peak hours for ice making. The program analyzed here is one of simple incentives, like the existing PG&E program, but more actively pursued. Given the limited experience of TES, the system effects for the purposes of this study are based on engineering data, modeling of individual representative building performance, and simple assumptions of market penetration. The RAC program is much more familiar, both to LBL and PG&E personnel. The program envisages the exogenous imposition of an efficiency standard for residential cooling appliances that is substantially tighter than the planned California standards, which are themselves stricter than national market norms. LBL's considerable experience at modeling the residential energy sector of the PG&E system is drawn upon to simulate the effect of this efficient air conditioner standard. The consequences of the standard are modeled using the Lawrence Berkeley Laboratory Residential Energy Model (LBL-REM), (McMahon, 1987). For both programs, the load and energy effects are translated in LMSTM inputs and the programs are evaluated using LMSTM and LBL's own models.

In general, the approach of the case study is to specify a demand-side program using data from PG&E and exogenous sources, to observe how this program would change the use of supply-side resources in the planning horizon (1989-2003), and then, to make a supply-side adjustment, based entirely on the judgment of the modeler, that seems to be the best cost-saving alternative available. The addition of the demand-side program typically results in the deferral, cancellation, or premature retirement of generating capacity. Changes in resource mix, marginal cost, and the present-value of total costs are the main measures of overall system impact. A rudimentary cost-benefit analysis is performed, from the perspective of the customer, the utility, and society-as-a-whole.

II. BACKGROUND

1. Least-Cost Planning

The term "Least-cost planning" is used to describe a planning process that evenhandedly considers both demand- and supply-side resources when planning for future demand. The principle of LCP is simple: choose the set of supply- and demand-side resources that will reliably meet the forecast demand for electricity services at the lowest direct cost (Pignone *et al.*, 1986). In practice, however, LCP is immensely difficult because of the complexity of power systems, the high degree of system reliability demanded, the distant planning horizons, the absence of a functioning market for electricity, the uncertainty of various key parameters such as fuel prices, and the vagaries of the regulatory process. Most taxing of all is the multitude of planning options possible and the limited information about them available. In the past, utilities kept demand research and forecasting separate from generation planning. Demand forecasts were simply an input to the generation planning process. Starting in the mid-1970s, the utility industry began to consider conservation and load management as resource alternatives. Even after more than a decade, however, few utilities can plan demand- and supply-side resources in an integrated fashion. Such integration is necessary to assure that utilities can identify least-cost plans.

A lack of integration in the planning process exists because LCP is complex and costly. Modeling supply-side resources requires probabilistic simulation techniques that are computationally intensive. In supply-side planning, chronological-load information often is dropped intentionally to reduce computational requirements. To properly evaluate specific demand-side program properties requires that chronological information be retained or, at the very least, that each year of the planning period be modeled as many separate sub-periods. Typically, the simulation of many supply plan/demand forecast combinations must be run to evaluate all the alternatives, further multiplying the computational requirements. In practice, screening curves could be used to reduce the number of options considered.

In this study, therefore, true LCP is not being conducted. Because all conceivable demand- and supply-side alternatives and combinations over all time horizons are not systematically identified and tested, the plan derived cannot be designated least-cost. The conclusions drawn are only that one policy alternative is less expensive than one other; this process would have to be repeated a number of times across all alternatives to find the true least-cost trajectory. But, then again, this is a young science.

2. Utility Simulation Models and LMSTM

The use of a simultaneous model like LMSTM permits an integrated approach to utility planning because it incorporates a detailed specification of both supply- and demand-side resources. Most production-cost models used by the utility industry today sort all hourly loads in the year according to size, and allocate resources according to this distribution (i.e., chronological-load information is lost). This technique is known as the equivalent load-duration-curve method. By contrast, LMSTM is a chronological model. Resources are dispatched against the loads of typical days, known as "daytypes." This method makes LMSTM a potentially more accurate way to model time-variant load management programs, time-of-use (TOU) pricing, and time-dependent supply resources (*e.g.*, hydroelectric power). Another feature that makes the model good for integrated resource planning is that demand in one year is dependent on the prices set in the previous year. This allows the model to capture price-induced impacts on demand.

LMSTM is made up of six submodels: demand, supply, financial, rates, evaluation, and control. Each submodel (except evaluation) has its own set of inputs, and each submodel (except control) produces a report as output. Integrated simulation is possible with LMSTM because the submodels share information as they are executed. Many important linkages are thus captured. Rates can influence demand, via price elasticities set in the demand submodel. Because utilities are obligated to meet demand, the demands generated by the demand submodel obviously influence generation in the supply submodel. The supply submodel can influence demand in two ways. First, certain conservation measures may be made "dispatchable," meaning that the supply submodel can reduce demand if the cost of generation exceeds a pre-specified level. Second, the supply model may influence fixed and variable costs in the financial model, which influence rates and, in turn, demand.

The two most important submodels are demand and supply. It is in these submodels that the majority of information characterizing a demand-side program is contained. These submodels are described below.

a) Demand Submodel

The basic level of aggregation in the demand submodel is the typical daytype. The goal of a chronological model is to simulate dispatch as it really occurs, that is hour by hour, but not to dispatch similar days more than once. To this end, LMSTM models 16 typical daytypes in each year, four each for four seasons. The major imputs for each daytype is a system diurnal load shape derived from historic data and an energy use ratio (EUR) that relates the electricity usage on any daytype to the levels on the others. The loads in the 16 daytypes can be set to change over time. Typically they grow at a rate specified by a demand forecast. They can also change as a result of a demand-side program. A demand-side program is also represented by 16 typical load shapes. Usually these loads grow over the years of the simulation period as the result of more customers adopting the demand-side technology. Because demand-side programs usually reduce load, the load shapes of the demand-side program will typically be negative.

b) Supply Submodel

The supply submodel characterizes the electricity generating units of a utility and dispatches resources to meet the load specified in the demand submodel. The basic level of aggregation in the supply model is the supply *technology types*. At this level, unit-specific data such as capacity, fixed cost, variable cost, operating constraints (*e.g.*, minimum operating level or energy limits), scheduled maintenance, and forced-outage rates are given. Because of the random-outage nature of supply resources, there are many possible combinations of supply-side resources that could be called on to meet demand. For example, consider a supply system that is perfectly reliable except for a thermal unit that has the characteristic of being randomly unavailable 20% of the time. LMSTM could model the supply system with two runs: one with the thermal unit available and one with the thermal unit unavailable. The weighted-average of the two runs (0.8 weight for the first run, 0.2 for the second) would be the expected results of the supply model. For nearly all real utility systems, performing a simulation for every possible resource combination is computationally very expensive. As a clever way to reduce computational burden, LMSTM puts technology types into one of 24 *technology groups*. These groups contain types with similar variable costs. By putting types into groups, LMSTM is able to reduce the number of random-outage combinations in an efficient manner. Even with this group representation, the number of possible resource combinations is still very large. Thus, LMSTM takes a user-specified number of resource combinations and chooses the best combinations given the user-specified constraint. For each of the resource combinations that LMSTM chooses, the model simulates dispatch for each of the 16 daytypes. The results from each combination are multiplied by their weights and summed to produce expected generation results. The main outputs of the supply submodel are expected generation (in GWh) by technology group and the expected hourly marginal cost for each of the daytypes in each year.

The methodology of LMSTM is described in more detail in previous demand-side planning research conducted at LBL (Pignone *et al.*, 1986; Kahn *et al.*, 1987) and by its authors (DFI, 1982, 1984, 1985).

III. METHODOLOGY

In this section, the important methodological issues faced when performing demand-side program analyses are addressed. The description focuses on the practical issues facing a demand-side planner. The case-study methodology for PG&E draws on methods developed in previous LBL work (Kahn, 1986; Eto *et al.*, 1986), and also involves some new techniques and programs.

The introduction of a demand-side program can affect a utility system in several ways. If the program improves load factors,[1] the program will usually reduce unit production cost. This reduction in cost comes both from fuel-cost savings and capacity-cost savings. Naturally, there are always costs involved in operating the demand-side program. The supply-side cost savings of the program minus the costs of operating it are its net benefit. However, there are transfers taking place between the utility and its customers, so the net benefits of the demand-side programs are estimated from both individual perspectives, the company's and customers', as well as from the societal viewpoint.

1. Steps to Perform a Demand-Side Program Case Study

Because the demand-side program can affect a utility system in several different ways, the incorporation of demand-side impacts into LMSTM and analysis of the results require an iterative process. These steps are described below.

a) Base-Case Simulation

The base-case run incorporates the current demand and price expectations of the company and the established supply plan that reliably meets that demand. The introduction of the demand-side programs is treated as a deviation from this base-case. That is, although LMSTM is run numerous times for each policy case, the model is not recalibrated to future expectations. This introduces some biases into the analysis that do influence results. For example, the lengthy process of specifying the seasons and daytypes in LMSTM, which is described in the stage 1 report, leads to a description of the world, embodied in loadshapes, that remains in place for the duration of the study. Dealing with the load data is just too cumbersome to permit any sensitivity on the definitions chosen. Although it is reasonable to expect weather conditions will be the same in base and policy cases, changing supply conditions might still warrant the redefinition of the seasons, if, for example, the effect of the program is to make a marginal month better placed in another season. Such effects should be small and are ignored in this analysis, and the base-case specification is invariant. This kind of deviation from true LCP would be the hardest to rectify. As anyone with experience in large scale modeling can testify, it is so difficult to calibrate the model initially and generate credible base case results that most of the model's inherent capabilities have to be artificially constrained. The base-case specification is described at length in the stage 1 report and is summarized in Section IV.

b) Demand-Side Program Specification and Initial Policy-Case Simulation

While LMSTM is capable of determining demand changes based on estimates of price behavior, adoption of new equipment, and engineering estimates of load characteristics, in this study, load shape changes are determined exogenously to LMSTM. The reason for this decision

[1] *Load factor* is a dimensionless measure of the use of a utility's capacity. It is equal to average load (usually over a year) divided by peak load.

is simple in the case of TES. As is seen in Section V, the sources of information about the system impacts of TES come from engineering information and simple market penetration estimates[2]. Virtually no information is available on how potential TES users would respond to particular incentives, either in the form of up-front incentive payments to adopt TES or in the form of attractive pricing. Creating a accurate model of TES market penetration is, therefore, unrealistic at present. In the case of RAC, LBL's extensive experience of modeling PG&E using LBL-REM, together with the sophistication of LBL-REM as a model of residential energy use made using it an *a priori* superior alternative to LMSTM's own demand side module. Further, the challenging exercise of running two models in tandem also always leads to valuable new insights into the interconnected nature of the least-cost problem, the limitations of both models used, and the importance of various assumptions in driving results.

In keeping with common practice among LMSTM users, the approach to specifying the demand-side programs is "top-down". This means that only the programs' incremental impact on the system load is modeled, rather than the system load being built-up from its constituent end-use loads which are individually altered by the demand-side program. As described in the stage 1 report, the entire PG&E area in the base case is represented by one set of load shapes. There are 16 of these shapes, one for each LMSTM daytype, that were derived from 1983 PG&E load data. Using 1983 loads as the basis of the system load characterization was a choice made in the belief that, of the years available, 1983 provided the most "typical" weather and economic conditions, and that averaging over several years would tend to dampen interesting extremes. Weather data is also an input to LBL-REM which generates the load effect of the RAC program, and to DOE-2.1 which calculates the load shapes of the TES program. Achieving consistency between the weather inputs to each of these models is impossible in practice and this raises some interesting questions which are discussed in Appendix B.

The RAC load shapes were derived in a parallel way to the base case shapes, using a variant of the same program, DTSPLT, which is described in the stage 1 report. The raw data set used was actual hour-by-hour load decrements produced by LBL-REM. The Hourly Model works from a rigid set of annual load shapes based on past field observations for the various appliances modeled and scales these shapes up to meet a target energy use dictated by the forecast energy usages calculated in LBL-REM.[3] The load decrements were derived by differencing two runs, a base case calibrated to the future as incorporated in the LMSTM base case specification, and a policy case featuring the appliance efficiency improvements envisioned in the policy case. In other words, the output shapes from the Hourly Demand Model are identical year-by-year, and the following years contain no new information not seen in the first year, except for energy use which can be taken directly from LBL-REM. For the purposes of this study, however, there is nothing to be gained by analyzing the load shapes output by the LBL Hourly Model year-by-year, and it would be very cumbersome to rerun the entire procedure using different weather, so the 2003 load output was taken to be a fixed portrayal of the load decrements that the RAC program would produce, and LMSTM load shapes were derived from that year only, in exactly the same way that in stage 1 the system loads were derived from the 1983 loads only on PG&E's historic loads tape. Only the change in GWh sales was matched annually. The

[2] LMSTM can calculate penetrations and recalculate load curves but in this study that option was not used.

[3] Actually, the model works from matrices temperature and fractions of air conditioner turned on at any hour, but the result is that the shape of demand is fixed.

EUR's were simply calculated by summing the load decrements across all the hours included in each of the daytypes.

Notice that LMSTM has a similar limitation to the LBL models; namely, each end-use has only one shape. However, in LMSTM the full year is represented by only 16 X 24 = 384 observations. In an ideal LCP world, the shapes would be simulated year by year as the efficiency of appliances varied, and sensitivities on the weather used would delve into the uncertainties stochastic weather introduces.

The incremental load impacts of TES are estimated in a fashion that is generally similar to RAC. End-use loads both before and after the demand-side technology is adopted are estimated, the difference is taken to find the load impacts, the load impacts are sorted in a way appropriate for the LMSTM daytype definitions, and the average impact for each daytype is estimated. For TES, DOE 2.1 is used to simulate the cooling loads in a typical commercial office building in several cities representative of the PG&E service territory. A simple model is then used to calculate the incremental impact of adding TES to these buildings. These incremental loads are then "scaled-up" to match a TES penetration forecast based on previous research on the potential for TES. The development of the incremental TES loads are described in more detail in Section VI.

Once the demand-side changes have been specified, an LMSTM simulation is run. This first policy simulation does not include the effect of any supply-side changes. This run provides a primary estimate of the fuel savings of the demand-side program. This run also shows by how much the supply side needs to be adjusted to regain a proper supply-demand balance. The steps taken, once this information is known, are described below.

c) Additional Policy-Case Simulations

Once the demand-side changes are incorporated into the model, it is necessary to re-formulate the supply-side resource plan. The effects of a demand-side program will usually allow a supply-side resource to be deferred or canceled. Ideally, the utility planner should completely re-formulate the resource plan starting in the year the demand-side program begins to take effect using the same criteria used to formulate the base-case. In practice, the complete set of criteria used to formulate the base case, including non-economic supply constraints, may not be available, and the number of resources that can be deferred is limited. Under these conditions, the supply-side adjustment consists of choosing the best possible deferral of a generation unit given the demand-side changes. For example, a peak-shaving program should result in a deferral of peaking capacity and an energy conservation program that has a relatively flat load impact should defer new baseload capacity. It is desirable that the policy case have a neutral or beneficial effect on system reliability, so any supply-side adjustment in the policy case should not cause reserve margins to fall to a lower level than in the base-case.

Additional LMSTM iterations may be required as a result of a demand-side program's "secondary" effects on the supply-side. An important possible secondary effect in the case of PG&E is the change in its fuel prices. Two sources of purchase energy in the PG&E system have fuel prices that are endogenously determined: geothermal steam and power from Qualifying Facilities (QF's).[4] A demand-side program may either reduce or increase system marginal

[4] QF's are independent power producers from whom utilities are obligated to buy power under the Public Utilities Regulatory Policies Act (PURPA). QF power is priced at the system marginal costs averaged over a period of time (*e.g.*, portion of day, season, or year).

costs. Typical conservation and load-management programs reduce marginal costs on average but a program like TES may increase marginal costs due to increased off-peak loads. Regardless of the direction, such changes in marginal cost, if significant, require a new computation of QF avoided costs. Geothermal power prices, which are determined by the relative share of both oil/gas and nuclear resources in total electricity generation are also affected by changes on the demand side (Kaiser Engineers, 1986). Because demand-side programs are usually designed to reduce or flatten load, they usually decrease the fraction of oil and gas generation and, thus, decrease the price paid for the geothermal power.

This is the point at which the iteration question arises, and it arises in steps. The results of the first LMSTM run suggest supply plan adjustments which are incorporated in subsequent LMSTM runs. These runs, however, will in turn suggest modifications not only to LMSTM inputs, such as the geothermal price, but also to other assumptions, such as the inputs to LBL-REM. Further LBL-REM runs will then produce slightly different load shapes and the entire process should be repeated. In an ideal LCP environment, all of these steps would be automated, and the beauty of taking the road not taken in this study, that is, to rely solely on one model, is that all of this simultaneity can be taken into account without the intervention of the user. In this study the only important iteration attempted was on the price trajectory seen by LBL-REM customers for the RAC program. Figure III.4 shows an index of real rates that emerged from the LMSTM base case run. Obviously the major factor that makes this trajectory deviate from an even path is large capital cost additions. The effect of recent construction is seen in the rise in rates from 1987 to 1990. Even so this increase is only in the order of 4.5% real per year, because of LMSTM's treatment of Diablo Canyon which gets into rate base in 1985. This is a cost of LMSTM's ratemaking assumption that the company is made whole every year, which requires that a new plant is rate-based in the same year it is commissioned. This is clearly an unrealistic assumption in the case of Diablo Canyon, and to properly accommodate the effect of non-conventional ratemaking, various modeling tricks can be used. Such tricks were avoided in this study because the importance of this issue should not be great. For the TES case, market penetration is derived from rough estimates of potential, and the response of TES customers to changing prices is overlooked, so a different price trajectory would have no effect on the energy and load impact of the program. In the RAC case, the index portrayed in Figure III.4 is the actual one shown to the LBL-REM customers, but the program only gets under way after 1990, when the issue becomes mute as far as current purchase decisions are concerned. That is, the price of electricity in 1990 is similar whether Diablo Canyon is rate based in 1985 or 1988. The one area of concern is decisions made 1986-1989, which LBL-REM is modeling before the policy program begins. The appliance saturation base year is 1986, because LBL-REM is calibrated to hit the results of the 1986 Residential Appliance Saturation Survey.[5] A price trajectory that is too gentle in this period would result in too many appliance purchases. These appliances are then in existence until 1998, at least, which will in turn diminish the retirement rate and lower the number of customers buying air conditioning for the first time during the falling real price period of the early 1990's. The result will be to reduce the rate of penetration of the new efficient appliances after they become mandated in 1989 onwards. However, this effect would most likely be very small, and, in fact, past experience with LBL-REM has shown that it is quite insensitive to price change, and it is unlikely that any sensitivity cases using varying price

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[5] Information supplied in a private communication by Lisa Skumatz of PG&E.

trajectories would produce significantly different results. Nonetheless, in general, properly taking care of feedback effects through rates should be a priority for least-cost planners.

2. Evaluation Programs

Three special FORTRAN programs were written to facilitate a complete analysis of the program results.

a) LODAV

An important methodological issue is how to translate a MW of avoided demand into an impact on the system's capacity. Often an estimate of the capacity saving generated by a demand-side program is simplistically assumed to be equivalent to the absolute peak savings for the year. To the supply-side planner, however, what matters most is how the demand-side program is able to reliably meet load. Ability to reliably meet load is most commonly measured by a resource's ability to reduce loss-of-load probability (LOLP). Ideally, a demand-side program's impact would be measured by averaging the hourly demand-side load impacts weighted by the corresponding system hourly LOLP's. Unfortunately, LOLP is not a direct output of LMSTM and, thus, is difficult to use for weighting the demand-side changes. LOLP is not routinely available from a chronological model, such as LMSTM, so the best surrogate should be the reported unserved energy. However, using our input files to LMSTM produces unsatisfactory unserved energy results that are not a reliable guide to system reliability. Because high LOLP hours are closely correlated with high load hours, however, a simple way to measure the avoided capacity value of a demand-side program is to measure the load effect over a certain number of the highest-load hours and take the arithmetic average. This is a poor substitute for an LOLP-weighted average, but it does nevertheless provide valuable insights into the realistic system planning implications of a demand-side program.

To facilitate computation of the average load impact on high-load hours, a program called LODAV was written. It reads the output files from an LMSTM run and averages the load impacts across a specified number of the highest-load hours. The steps involved in this process are the following:

1. LODAV reads the CONTROL.N file of the base case and converts the seasonal fractions it finds there into a number of days for each daytype.
2. LODAV reads the SUPPLY3.T file from both the policy and base cases and estimates the change in load for every hour of every daytype.
3. The matrix of system loads and load-changes are ordered from highest to lowest system loads.
4. The highest-load hours are counted off, each observation being multiplied by the number of days of that daytype in the year, and the average found. Obviously, some interpolation is necessary because the number of hours requested is rarely an exact multiple of numbers of days of daytypes.
5. This process is repeated for every other year of the study period; the intermediate years are interpolated.

With this method chosen, the problem becomes choosing the appropriate hours of averaging. An inspection of GRASS reports prepared for PG&E's 1985 Long-Term Plan (LTP) shows that the large majority (approximately 90% in 1989) of all LOLP occurs in the top 10 percent of the hours in July and August--equivalent to approximately the 150 highest hourly loads. Thus, we will use the average load impact on the highest 150 hours as our primary assumption in determining the load impact. The results of the load averaging process are interesting. In general, the average load impact on the highest-load hours is highly dependent on our assumptions concerning the correlation of the end-uses that we study and the system load. Also, the nature of the demand-side programs studied make the average load impact very sensitive to the length of averaging. For the case of TES, there is the additional complication that the demand-side program *adds* loads on some of the highest-load hours. Thus, sensitivities are performed to see how the value of the demand-side program changes under lengths of averaging. The results of the load averaging process are discussed in more detail in Sections VI and VII.

While the averaging method described above typically reduces the capacity value of a demand-side program relative to its absolute peak savings for the year, several factors increase its value. First, a MW of avoided demand saves transmission and distribution losses. We assume that these losses are 6.8% of generation. Second, the absolute size of a system reserve margin may be reduced if supply-side capacity is deferred or canceled. In other words, a MW of avoided load saves reserve margin capacity as well. We assume a system reserve margin credit of up to 20%.

a) EVALER

Another cost of not relying on one integrated model, such as LMSTM, is that the summary results and cost-benefit analysis automatically calculated by the model are not available. As an alternative, a simple program was written to carry out a rudimentary cost-benefit analysis of the results.

The motivation for writing EVALER is threefold. First, the revenue loss calculation can thus be carried out exogenously which permits the introduction on non-linear rates, a critical issue in the TES case. Second, external calculation permits a clearer understanding of the structure of costs and benefits, and, further, permits ready sensitivity anlayses without the computation burden of repeated LMSTM runs. And third, joint cases involving more than one demand-side program can be run and yet each case be individually evaluated. Developing and writing EVALER constituted a significant part of the work of this stage of the project. Every feature that is added to such a program seems to suggest another that one can no longer live without, and it is difficult to know where to draw the line. What was begun as a simplifying procedure to make LMSTM outputs more comprehensible became a minor programming challenge. One of the most interesting problems confronted in the writing of EVALER is the problem of the joint case. One of the vexing issues of LCP is how all of the alternatives can be fairly considered at the same time. Clearly synergisms and conflicts will exist between different programs and yet all must be even-handedly considered. Most demand-side planning has ignored this and evaluated only one program in isolation. This is a valid approach if and only if it has such a small effect on the system that a *ceteris paribus* assumption holds. Clearly, the two programs considered here are both large enough to affect the valuation of the other. For example, the existence or non-existence of the over 400 MW of peak saving in 2003 of the RAC program has a significant influence on the cost savings of the further peak saving that TES could deliver. The first changes made to the supply plan should be the ones that yield the biggest cost saving, and those deferred later will generate lower returns. However, if both programs are in existence in the simulation, which of the two programs should get credit for the deferral of the more costly plant? There is no easy answer to this and other synergism issues, and, indeed, even unraveling which share of observed capacity and fuel savings are attributable to each program is difficult enough.

Most of EVALER's results are based on a comparison between the SUMMARY.T files of the two cases. A special input file of parameters, such as the discount rates for the company, the customer, and society, is also read into EVALER. The third source of inputs is the output annual peak load savings from a LODAV run. These are read automatically by EVALER from LODAV output files. It is important to note the distinction between two estimates of peak saving that EVALER has. The first comes from the differences between the peaks reported in the two SUMMARY.T files, and the other is the averaged peak saving that is output from LODAV. Both are available for analysis, but as explained above, the LODAV value is a far more interesting one, and it is the one used in the analyses reported here.

The outputs of EVALER are three matrices of data, examples of which appear as Figures III.1, 2, and 3. The first two simply report the differences found between the two SUMMARY.T files. Figure III.1 echoes the assumptions embedded in this particular run, and shows the changes in bus bar output, sales, and installed capacity. In this example, the policy case has the RAC program on, and the TES one off. The result is that company sales, as reported in the "be.sls" and "af.sls" (before and after sales) columns fall by 258 GWh by 2002. The rightmost column labeled "ch.icp" reports the change in installed capacity EVALER finds in the SUMMARY.T file of the policy case. The changes reported here are the adjustments that have been made to the supply plan. In this example, three chunks of capacity are eliminated, 50 MW in 1990, a further 125 MW in 1996, and yet another 125 MW in 2003.

The second block shows the changes in reported peaks for each season. For the RAC case, the maximum effect is always in the summer so the net change in summer peak is the absolute peak saving described above. The columns headed b.sup and a.sup (before and after summer peak) show the peak saving effect of the program, and the effect is shown in the following column, ch.

The third block, Figure III.3 is the most interesting and important one. It reports the results of the simplified cost-benefit analysis. The first two columns show the sales effect of the two programs, and the third the peak effect. Note that in this example the peak effect is reported as rising to a maximum of 274.4 MW, far short of the 415 MW reported in the second block. This difference is the result of peak averaging, which in this example, as can been seen in Figure III.1, is over 150 hours. The following column shows the policy load factor of the program. This example shows that the RAC case has a low load factor, and is indeed an effective peak shaver.

The next two columns show the revenue impact of the program. In the case of RAC, the revenue change is estimated in the following way. The sales losses are all assumed to fall in the upper tier of the baseline residential rate, 10.23 ¢ at present. That is, it is assumed that any air conditioner user is consuming enough electricity in the cooling season to be in the upper tier of the rate structure, and, consequently, any loss of sales to any customer under the air conditioning case must be evaluated at the higher tier price, not the average price of electricity.[6] This price is escalated by a price index that is derived from a prior LMSTM run,[7] and is further inflated by the background inflation rate, which is 5% everywhere in this study. Unlike RAC, the revenue

[6] The current tier boundaries for ordinary customers are as follows: R = 520, S = 440, T = 220, X = 310. And for all-electric households, they are: R = 740, S = 660, T = 620, X = 400.

[7] Over the period of 1987 to 2003, the average escalation in real rates is 1.3%/year. After 2003, the escalation rate is zero.

loss from TES comes primarily from customer *demand*-charge savings. Using the load shapes and EUR's estimated in Section VI, we estimate the revenue loss per year per kW of load saved by TES. This number is multiplied by the total size of the TES program (in kW of avoided demand) to get the total revenue loss for a particular year.

At this point dealing even with two programs becomes confusing. The sales and revenue effects of the two programs have to be decomposed. This is non-trivial because of the highly non-linear nature of electricity rates. In this case, the residential rate is increasing block with differing allowances in each of the regions, and the rate faced by TES customers is time-of-use (TOU) with a stiff demand charge. If, as in this work, prior runs have been made with each of the programs operating independently, the sales changes derived from these runs can be used, and this is the way the issue is resolved here. However, a LCP dilemma remains. If several programs are running simultaneously, unraveling the constituent effects would have to be automated in some manner. Simply assuming that sales changes have a proportional effect on revenues would be a poor assumption. The next column shows the change in variable operating cost that EVALER has found in the SUMMARY.T files.

The remaining columns show the results of the cost-benefit analysis. The net benefit of RAC over various time horizons from the company (PG), customer (CU), and societal (SO) perspectives are shown at the foot of the table. The 27 year result, which may seem to be over a rather arbitrary horizon, is actually the most important. The assumption made here is that the RAC program arbitrarily stops in 2003. However, clearly the effects of the program do not stop dead at that point. Sales continue to be lower after that year, and customer bills continue to be lower. Rather than confusing the analysis by trying to account for these effects year-by-year, the assumption has been made that 12 years after the end of the program all of the efficient equipment purchased in the active years of the program is scrapped and the program is considered dead.[8] This is roughly the same lifetime that is assumed by LBL-REM. Although it has different life expectancies for each of the three appliances subject to the new standard, 12 years is a 2003-sales-weighted average. The rate of customer bill savings continue at their 2003 level for the period 2003-2014.

Two methods are used to calculate the capacity value. The first method, which we call Method 1, computes the value of the capacity savings by a capital cost--\$350/kW in this example--as the load savings are realized. This is an economists' method of valuing avoided capacity at its ''overnight'' capital cost, wherein anything not bought is money immediately in the company's pocket. The second method, known as Method 2, uses the results of financial submodel of LMSTM from the base and policy cases to compute a stream of revenue-requirements savings that result from deferring a specific supply-side resource. This method, while theoretically more accurate, is problematic because the stream of revenue-requirement savings typically extends beyond our simulation period. As is apparent in Figure III.3, the two approaches result in very different streams. Some of the reasons for the discrepancies are the following:

1. While Method 2 uses the same value for overnight capital cost that is used in Method 1, it increases the cost to account for interest accrued during the construction of the plant. We assume that the lead time for oil-steam refurbishment is 5 years. Also, Method 2 would

[8] Both LMSTM and LBL-REM assume that all new equipment is bought on the first day of the test year.

account for real escalations in the cost of generating capacity. We assume, however, very little increase in the real cost of capacity.

2. The cost of money to a utility may be significantly higher than the discount rates used by EVALER. Method 2 uses a weighted-average cost of capital (WACC) for PG&E of 10.4% pre-tax or 16.9% if an adjustment is made for taxes. Thus, if the discount rate used by EVALER is lower that the WACC used by LMSTM, the value computed by Method 2 will be inflated relative to Method 1 because of differences in the time preference of money and because the utility is required to pay income taxes to the government. In addition to income-tax transfer reflected in the after-adjusted WACC, Method 2 accounts for a property tax of approximately 1%.

3. The amortization period for the revenue-requirements method is 39 years and the deferrals in this study are anywhere from 1990 to 2003. Because the fuel-savings benefits typically end before the capacity-savings benefits end, several years of the revenue-requirement savings may get truncated by EVALER. However, because of discounting, the majority of the capacity-savings, in present-value terms, is typically counted.

The first two factors will tend to make Method 2 value capacity savings more than Method 1. If these were the only two factors affecting the discrepancy, we could take the ratio of the present values of the two methods as a measure of the amount that Method 1 underestimates the real cost of capacity to the utility relative to Method 2. Such a ratio would be similar to those computed by Leung and Durning (1978). We calculate this ratio in the results sections. However, confounding our calculation is the third factor which is that EVALER will typically ignore several years of the revenue-requirement savings and, thereby, diminish the capacity computed by Method 2. Thus, our comparison of Method 1 and 2 must be considered approximate.

Obviously, the effect of the first two factors outweigh the third because, overall, Method 2 typically values the avoided capacity, in present-value terms, by a factor of 2 or more.

3. Evaluation of Results

Once a demand-side case that incorporates all the primary and secondary effects described above has been run, the value of the program is estimated. The value of a demand-side program should be measured in several ways. Demand-side programs have impacts that vary over time and vary with respect to different parties, so no single measure is adequate. The following summarizes the measures of impact presented in Section VI.

a) Supply-Side Impacts

The first measure presented is the change in production of electricity, disaggregated by resource. LMSTM's supply submodel produces these outputs. Production disaggregated by resource is shown on an annual basis for selected years of the simulation period. The output attributable to marginal resources is of particular interest because a demand-side program would probably affect the use of these resources most. On the PG&E system, oil and gas, Northwest economy energy, and pumped storage are marginal for most of the year; however, other hydro and nuclear also appear on the margin at times of low load.

Marginal cost is the expected cost of producing an additional unit of electricity. For each year of the simulation, LMSTM calculates hourly marginal costs for each of the 16 daytypes. This information quickly indicates the value of new supply and demand alternatives. Any viable supply- or demand-side alternative must provide power at a cost less than the system marginal costs unless the capital cost savings overwhelm this effect. As a demand-side program changes marginal costs, it changes the set of attractive alternatives. Thus, it is very important to keep an eye on marginal costs when evaluating a variety of supply and demand-side options.

Another useful measure of the nature of a utility's marginal resources is the incremental energy rate (IER). The IER is computed by dividing a utility's annual average daily marginal cost by the residual fuel oil price. The IER measures the degree to which oil and gas resources are on the margin. The units of the IER are Btu/kWh[9] and the IER represents the equivalent heat rate that would have to be achieved by a hypothetical utility that burned only oil and gas on the margin so as to have the same marginal costs as the utility being studied. Because the most efficient oil and gas units today have heat rates of approximately 8,500 Btu/kWh, a utility that has an IER below 8,500 has a significant amount of non-oil resources on the margin. Because IER's are normalized by the oil and gas price, they are especially useful as a measure of changes in the mix of marginal resources over time.

b) Demand-Side Program Valuation

As an overall measure of the value of a demand-side program, the total cost of supplying electricity in the base case is compared to the total cost of supplying electricity plus the incremental cost of new equipment in the policy case. The total cost of the base case minus the total cost of the policy case is the net benefit of the demand-side program. As discussed in Section III.2.a, we used a post-processor to LMSTM, called EVALER, to compute the net benefit from the perspective of society, the customer, and the utility. The following discusses some of the important assumptions of our cost-benefit analysis.

An important assumption is our treatment of the divergence between costs to the utility and costs to society. Our Method 2 of valuing avoided capacity uses LMSTM's financial submodel to compute the revenue requirements of added capacity. Method 2 will diverge, however, from an estimate of true social costs if the utility's discount rate differs from society's and to the extent that any pure transfer payments are measured as costs. Examples of such transfer payments are taxes and payments to QF facilities at prices above the cost of QF generation. In addition, neither of our methods explicitly accounts for the environmental costs of any of our scenarios. This can also distort our calculation of societal net benefit. Because of the difficulty in calculating environmental costs and because the perspective of the utility is emphasized in this study, however, we will not attempt to account for environmental costs.

Other important assumptions are a part of our calculation of the utility's benefit. Any calculation of the net benefit to the utility depends heavily on the rate-making assumptions used. If we assume that prices in the future will be calculated according to strict rate-of-return regulation, we could easily conclude that the net benefit of a program to the utility would be zero. Under rate-of-return regulation, a utility is compensated fairly for the costs it incurs for supplying power, it would not receive more or less compensation for promoting the program, provided it is a prudent resource. Instead, the entire net-benefit of the program under such regulation is passed on to customers. In the real world, however, changes in rates tend to lag changes in costs, so a program that reduces or shifts demand can have an impact on a utility's rate of return. The present value of the changes in utility profits is the net benefit of the demand-side program to the

[9] The inverse of IER, after adjusting for the different units of the numerator and denominator, is simply the thermal efficiency of an oil-burning unit. For example, an IER of 8,500 Btu/kWh is equivalent to a thermal efficiency of 0.40.

utility. More specifically, we set the net benefit to the utility equal to the capital and fuel-cost savings net of the revenue losses and direct incentives paid to adopters.

We base our revenue loss calculations on current marginal rates; i.e., exogenous to LMSTM. We assume these marginal rates grow only at the rate observed for average rates in the base-case run. This is an important assumption for PG&E because its rates are highly non-linear. A kWh avoided by a residential air conditioning customer will likely be from a tier whose price is above average prices. Similarly, customers adopting TES are on TOU rates that include large demand charges and differences in on- and off-peak energy costs. Thus, our revenue loss calculation will generally be large.

Our use of extrapolating current rates into the future may be viewed as a worst- or best-case estimate of the utility's net benefit, depending on the situation. If revenue losses exceed cost savings, then the utility's rate of return will be negatively impacted and the utility will be averse to investing money in such a program--even if the program is least-cost from a societal point of view. This situation will cause the utility to take, in effect, a "capital-minimization" strategy similar to strategies described in regard to supply-side investment decisions by Chao, Gilbert, and Peck (1984). Our measure of the net benefit in this situation is a worse-case; in reality, it is highly likely that some rate adjustment will eventually be made to increase the utility's rates of return.

If the revenue losses from the demand-side program are less than the cost savings, the utility will have an incentive to promote such a program. In this case, however, our calculation of the net benefit to the utility must be viewed as a best-case because it is likely that regulators would eventually pass part of the positive benefits of the program onto customers.

It is important to note the general asymmetry that exists between our characterization of rate regulation under demand- and the supply-side scenarios. In our base (supply-side) case, we assume that the utility is fairly compensated for all new supply-side resources in the supply plan. In the policy (demand-side) case, however, we assume that a utility's demand-side program has little effect on marginal rates and the utility's benefit (or loss) comes without any regulatory adjustment. In other words, the utility takes all the risk in the demand-side case, but none in the supply-side case. In reality, there are risks on both the supply and demand side and it may not be correct to assume that the utility will always be fairly compensated in the base case. If the utility were adversely affected in the base case, it would adopt a capital-minimization strategy from the start and might consider the demand-side program to be a better alternative even if it does cause significant revenue loss. While such a situation is exactly what happened to many utilities in the recent past, we will not model this scenario due to the difficulty of modeling the ratemaking process explicitly.

Our treatment of costs at the end of the simulation period also depends on our assumptions. Both demand- and supply-side resources have finite lifetimes. Often, the lives of the resources extend well beyond the period of analysis. While it is theoretically possible to extend the period of analysis for a very long time (40 years or more) to capture the full impact of a program, LMSTM's maximum simulation period is 25 years. Even if more simulation years were allowed by the model, such an approach to measuring end-of-period effects would be costly. There are other, more practical, ways to measure the end-of-period effect. Usually a demand-side program results in a stream of fuel-cost savings and a stream of capital cost savings. Once the penetration of the demand-side program has peaked, one can assume that the fuel cost savings seen in the latter years of the simulation may be extrapolated for as long as the mean life of the installations. These fuel cost savings would escalate with the price of fuel. The capital-cost savings depend on the quantity and cost of the deferred resources, the lifetime of the deferred resources, interest rates, and the method of depreciation. It is possible to add to the last year of the simulation a "one-lump" estimate of the remaining capital-cost savings. This one-lump savings would be equal, in present-value terms, to the remaining stream of capital-cost savings. Alternatively, one can estimate the mean "lifetime" of the capital-cost savings and assume that the savings seen in the latter years of the simulation may be extrapolated, with no escalation, for that mean lifetime. This latter method is used in EVALER.

Figure III.1

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BASE : #115; BASE CASE WITH BOTH TES AND RAC CAPABILITY 7/15/87

***** compared to *******

POLICY : #127; POLICY CASE WITH RAC ON AND S-SIDE DEFERRALS 17JUL87

****

BASIC ASSUMPTIONS

number of hours of peak averaging	:	150.00
utility discount rate (curr)	:	10.40
customer discount rate (curr)	:	8.00
societal discount rate (curr)	:	10.00
general inflation rate	:	5.00
retail price index for 1987	:	1.52
1987 tier2 price (c/kWh)	:	10.23
PGandE capacity cost (1987$/kW)	:	350.00
rac customer cap. cost (1987$/kW)	:	250.00
tes customer cap. cost (1987$/kW)	:	250.00
TES revenue loss factor (1987$/kW)	:	93.00

SALES EFFECTS

year	be.bb (TWh)	af.bb (TWh)	ch.bb (GWh)	be.sls (TWh)	af.sls (TWh)	ch.sls (GWh)	be.icp (GW)	af.icp (GW)	ch.icp (MW)
1989	86.401	86.393	8	80.423	80.416	7	27.917	27.917	0
1990	86.905	86.892	13	80.851	80.840	11	31.274	31.224	50
1991	88.614	88.594	19	82.471	82.453	18	29.990	29.940	50
1992	90.346	90.316	30	84.112	84.085	28	30.478	30.428	50
1993	92.132	92.085	47	85.775	85.732	43	29.956	29.906	50
1994	93.903	93.836	67	87.459	87.392	67	30.997	30.947	50
1995	95.724	95.636	87	89.164	89.076	88	29.786	29.736	50
1996	97.549	97.432	117	90.889	90.775	114	30.237	30.062	175
1997	99.804	99.645	159	93.015	92.867	148	30.295	30.120	175
1998	101.437	101.230	207	94.535	94.343	192	32.098	31.923	175
1999	103.017	102.797	220	96.009	95.805	204	30.635	30.460	175
2000	104.541	104.308	233	97.428	97.212	216	33.373	33.198	175
2001	105.992	105.746	247	98.782	98.552	229	30.880	30.705	175
2002	107.363	107.102	261	100.060	99.817	243	32.487	32.312	175
2003	108.646	108.368	277	101.251	100.993	258	31.402	31.102	300
2004	109.816	109.539	277	102.342	102.084	258	33.732	33.432	300
2005	110.871	110.593	278	103.319	103.061	257	32.172	31.872	300
2006	111.784	111.506	278	104.166	103.909	258	32.172	31.872	300
2007	112.542	112.263	279	104.867	104.610	258	32.172	31.872	300

PEAK EFFECTS

year	b.wip (GW)	a.wip (GW)	ch (MW)	b.spp (GW)	a.spp (GW)	ch (MW)	b.sup (GW)	a.sup (GW)	ch (MW)	b.fap (GW)	a.fap (GW)	ch (MW)
1989	13.22	13.22	0	15.15	15.14	10	17.08	17.07	12	13.66	13.66	0
1990	13.29	13.29	0	15.24	15.22	16	17.18	17.17	18	13.73	13.73	0
1991	13.57	13.57	0	15.56	15.53	24	17.55	17.52	29	14.02	14.02	0
1992	13.86	13.86	0	15.89	15.85	38	17.92	17.87	45	14.31	14.31	0
1993	14.15	14.15	0	16.22	16.16	59	18.29	18.22	70	14.61	14.61	0
1994	14.44	14.44	0	16.55	16.46	92	18.67	18.56	109	14.91	14.91	0
1995	14.74	14.74	0	16.90	16.78	119	19.06	18.92	141	15.22	15.22	0
1996	15.04	15.04	0	17.24	17.09	155	19.45	19.27	183	15.53	15.53	0
1997	15.37	15.37	0	17.62	17.42	202	19.87	19.64	238	15.87	15.87	0
1998	15.66	15.66	0	17.95	17.69	262	20.26	19.95	310	16.17	16.17	0
1999	15.95	15.95	0	18.29	18.01	278	20.63	20.31	329	16.46	16.46	0
2000	16.23	16.23	0	18.61	18.32	295	21.01	20.66	348	16.75	16.75	0
2001	16.51	16.51	0	18.94	18.62	312	21.38	21.01	369	17.04	17.04	0
2002	16.78	16.78	0	19.25	18.92	331	21.74	21.34	391	17.31	17.31	0
2003	17.04	17.04	0	19.56	19.21	351	22.09	21.67	415	17.58	17.58	0
2004	17.29	17.29	0	19.85	19.50	351	22.43	22.01	415	17.84	17.84	0
2005	17.53	17.53	0	20.14	19.78	351	22.75	22.34	415	18.08	18.08	0
2006	17.76	17.76	0	20.40	20.05	351	23.06	22.65	415	18.31	18.31	0
2007	17.98	17.98	0	20.65	20.30	351	23.35	22.94	415	18.53	18.53	0

Figure III.2

FINANCIAL EFFECTS

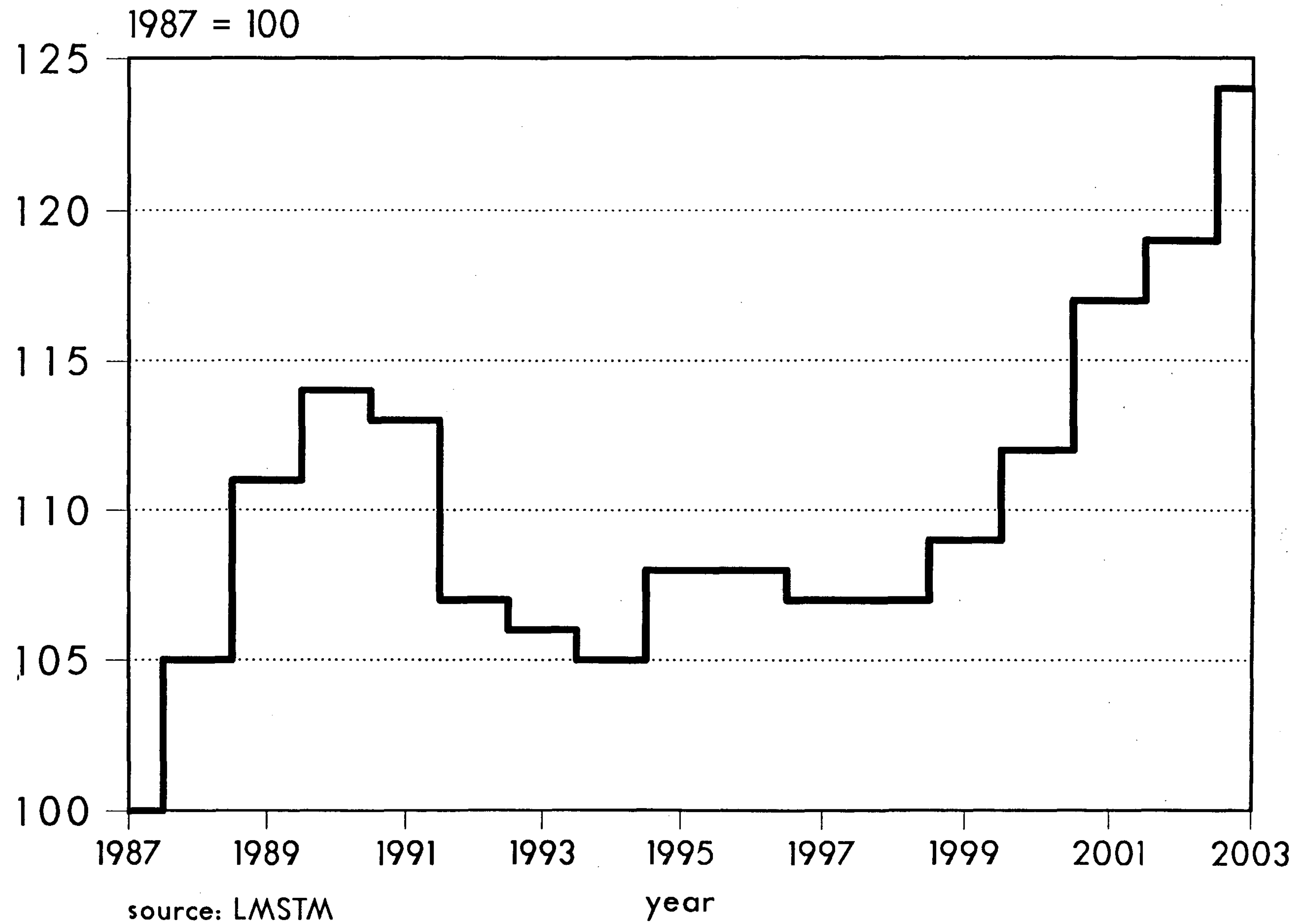
year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	7.3	.Ø	.Ø	7.4	.9	.Ø	.2	.Ø	-.7	-.6	-.Ø	-.7	-.6	-13.Ø	-11.1	-13.7	-11.3	-13.7	-11.3
199Ø	11.4	.Ø	9.2	8.1	1.5	.Ø	1.2	3.7	3.4	2.5	.7	.4	.3	-13.3	-1Ø.6	-9.9	-7.4	-12.9	-9.7
1991	17.7	.Ø	18.5	7.7	2.5	.Ø	1.5	4.Ø	2.9	2.Ø	.7	-.3	-.2	-14.Ø	-1Ø.3	-11.1	-7.6	-14.4	-9.8
1992	27.7	.Ø	32.2	7.7	3.9	.Ø	2.Ø	6.1	4.3	2.6	.6	-1.3	-.8	-14.7	-1Ø.Ø	-1Ø.4	-6.5	-15.9	-9.9
1993	43.2	.Ø	46.Ø	7.7	6.2	.Ø	2.7	6.5	2.9	1.6	5.9	2.4	1.3	-4Ø.3	-25.4	-37.3	-21.1	-37.9	-21.4
1994	67.4	.Ø	69.7	7.1	1Ø.1	.Ø	3.9	11.7	5.5	2.7	5.8	-.4	-.2	-41.8	-24.4	-36.3	-18.6	-42.2	-21.6
1995	87.6	.Ø	93.4	7.1	14.1	.Ø	5.1	12.3	3.2	1.5	5.5	-3.5	-1.6	-43.5	-23.5	-4Ø.2	-18.8	-47.Ø	-21.9
1996	113.8	.Ø	125.5	7.3	19.1	.Ø	12.7	17.4	11.Ø	4.5	24.8	18.4	7.5	-45.1	-22.5	-34.1	-14.4	-26.7	-11.3
1997	148.Ø	.Ø	157.7	7.6	25.8	.Ø	16.3	18.4	8.9	3.3	23.8	14.3	5.3	-45.6	-21.1	-36.7	-14.1	-31.2	-12.Ø
1998	192.4	.Ø	187.6	7.6	35.2	.Ø	2Ø.9	17.9	3.6	1.2	23.2	8.9	3.Ø	-43.3	-18.6	-39.7	-13.9	-34.4	-12.1
1999	2Ø3.9	.Ø	217.4	7.6	4Ø.2	.Ø	24.1	18.7	2.7	.8	22.5	6.4	2.Ø	-45.3	-18.Ø	-42.6	-13.6	-38.9	-12.4
2ØØØ	216.2	.Ø	23Ø.8	7.6	46.1	.Ø	27.4	8.8	-9.9	-2.7	22.Ø	3.3	.9	-46.5	-17.1	-56.3	-16.3	-43.2	-12.5
2ØØ1	229.1	.Ø	244.3	7.6	53.1	.Ø	32.4	9.4	-11.4	-2.8	21.3	.6	.1	-46.1	-15.7	-57.5	-15.1	-45.5	-12.Ø
2ØØ2	242.9	.Ø	259.3	7.6	61.2	.Ø	37.9	1Ø.9	-12.4	-2.8	2Ø.9	-2.4	-.5	-45.7	-14.4	-58.1	-13.9	-48.1	-11.5
2ØØ3	257.5	.Ø	274.4	7.6	7Ø.7	.Ø	52.1	11.5	-7.1	-1.5	46.4	27.8	5.7	-44.Ø	-12.9	-51.1	-11.1	-16.3	-3.5
2ØØ4	257.5	.Ø	274.4	7.6	74.3	.Ø	57.1	.Ø	-17.2	-3.2	44.7	27.5	5.1	74.3	2Ø.1	57.1	11.3	1Ø1.8	2Ø.1
2ØØ5	257.5	.Ø	274.4	7.6	78.Ø	.Ø	62.3	.Ø	-15.7	-2.6	43.5	27.8	4.7	78.Ø	19.5	62.3	11.2	1Ø5.8	19.Ø
2ØØ6	257.5	.Ø	274.4	7.7	81.9	.Ø	69.Ø	.Ø	-12.9	-2.Ø	42.5	29.6	4.5	81.9	19.Ø	69.Ø	11.3	111.5	18.2
2ØØ7	257.5	.Ø	274.4	7.7	86.Ø	.Ø	78.2	.Ø	-7.8	-1.1	41.4	33.6	4.6	86.Ø	18.4	78.2	11.6	119.6	17.8

	pvpg1	pvpg2	pvcu1	pvso1	pvso2
5-year time horizon (to 1992):	6.5	-1.3	-42.Ø	-32.8	-4Ø.8
1Ø-year time horizon (to 1997):	2Ø.1	11.1	-158.9	-119.9	-129.1
15-year time horizon (to 2ØØ2):	13.8	16.5	-242.6	-192.7	-189.5
2Ø-year time horizon (to 2ØØ7):	3.5	41.2	-178.5	-158.5	-117.9
27-year time horizon (to 2Ø14):	-1.7	63.5	-82.4	-1Ø1.9	-31.3
3Ø-year time horizon (to 2Ø17):	-3.Ø	69.3	-54.7	-87.Ø	-8.6
4Ø-year time horizon (to 2Ø27):	-5.5	79.7	2.7	-59.5	33.5

All time horizons count 1987 as year Ø. Beyond 2ØØ7 the benefit stream is assumed flat at the 2ØØ7 level.

Figure III.3

Figure III.4
Base Case Index of Real Electricity Rates



IV. BASE-CASE CALIBRATION

Calibrating LMSTM to the PG&E area was the objective of stage 1 of this project. This calibration was made using data mostly from PG&E's 1985 Long Term Plan (LTP) (PG&E, 1985a). Since then, there have been considerable changes in expectations of important input variables to LMSTM. Thus, some additional refinements to the base case were made for this case study. The following summarizes the important changes.

By far, the greatest change in factors affecting the PG&E system was that of declining oil prices. Oil prices fell by more than a factor of 2 from 1985 to 1986.[10] In 1986, the expectations of PG&E planners were that the $14.5/barrel price of residual oil would increase smoothly at an average rate of approximately 9.4% per year (nominal) over the next 20 years. Besides greatly changing the generation cost of the oil and gas units, reduced oil prices also affect the prices of competing fuels. The price paid to QF power, geothermal power, and economy hydroelectric power from the Pacific Northwest are all greatly affected by the price of oil. The model was updated to account for these revised price forecasts.

The second major change made to the base case was a decrease in the forecasted growth of electricity demand. In PG&E's 1985 LTP, it was expected that by the year 2005 the PG&E area would demand 140 TWh of energy and 25 GW of peak demand (PG&E, 1985a). In 1986, the California Energy Commission (CEC) forecasted a demand of 111 TWh and 23 GW by 2005 (CEC, 1986). This forecast is currently being used by PG&E for the purposes of demand-side planning.

Based on the old and new forecasts for energy and peak demand described above, it is clear that future load factors forecasted by the CEC in 1986 are lower than those forecasted by PG&E in 1985. Thus, it was necessary to adjust the hourly load shapes in LMSTM to conform with the CEC energy and peak-demand forecast. This was done by making the historical PG&E loads more spiked using a simple linear procedure. The method used to adjust the loads is described in Appendix A.

The third major change to utility expectations is the emergence of self generators. Self generators are customers that generate electricity for part or all of their needs. Essentially, self generators reduce the demand for electricity in the PG&E area. However, it is conventional to treat self generators as a resource with costs that are not paid for by PG&E. Currently, PG&E forecasts 1,432 GWh of self generation by 1989, growing to 6,025 GWh by 2003. The forecast for 2003 is 5.5% of total yearly generation. Many of the self generators in our base case would have been treated as QF's in the 1985 LTP. This is because many would-be QF's would rather keep the power for themselves now that avoided costs have fallen since 1985. Because of this, we made an appropriate decrease from the 1985 forecast in the QF forecast.

In summary, the three major changes made to the base case, lower oil prices, reduced demand, and self generation, greatly reduce the need for new supply resources in the 1990's.

[10] In the 1985 GRASS LTP run, the 1986 residual price was $5.60/MBtu. In 1986, the 1986 residual oil price used by SAM was $2.29/MBtu (both prices are in 1986 dollars) (PG&E, 1985a; PG&E, 1986a).

V. DEFERABLE SUPPLY-SIDE RESOURCES

The estimated max peak savings is 630 MW is the estimated peak-demand savings potential for the PG&E service territory by 2003. If such a demand impact were achieved, PG&E could certainly provide adequate service without some of the resources used in the base case.

The first step towards specifying a deferred resource is identifying resources that can be deferred. Because of contracting demand forecasts, the addition of Diablo Canyon, and the large influx of QF power that will occur by 1989, there is limited need for new supply-side resources during the period 1990-2003. The base case simulation includes approximately 3,400 MW of added resources from the period 1990-2003. However, the great majority of these resources will not be added by PG&E. Instead they will be added by municipal utilities, QF's, and self generators. Except for a 140 MW geothermal unit planned for 1995, no new PG&E-owned baseload resources are planned before 2003.[11] Other non-baseload, PG&E-owned resources planned in the base case are a 375 MW share of a new AC intertie to the Pacific Northwest and approximately 370 MW of increased hydro capacity. In addition, PG&E plans to refurbish 3,375 MW of existing oil-steam units (Woychick, 1986). Some of these oil-steam units would be retired if not for the refurbishment expenditures. Thus, ''extended-life'' oil-steam units may be considered a deferrable resource as well.

An easy way to choose the deferrable supply-side resource from the resources identified above is to find one that is used to supply a load that has a shape similar to the load saved by the demand-side program. It is possible to find the ''policy load factor'' for the policy by dividing the average load saved, ignoring any off-peak load added, by the peak load saved. Based on the load shape and the adopted EUR's, the policy load factor for TES is approximately 10% and for RAC 8%. The peak saving of RAC is especially concentrated near the system peaks so deferrals emphasize peaking units. By comparison, oil-steam units show capacity factors of the range of 10 - 18% in the base-case simulation. Because the oil-steam units have capacity factors roughly comparable to the quasi-capacity factor of the policy cases and there is an ample quantity of extended-life oil-steam units to defer, they are treated as the deferrable resource of choice.

The expected capacity cost of extending the life of oil-steam units is currently being debated. PG&E is considering extending the life of this capacity in a ''cold-standby'' form. This form of extension would retire the units from regular use, but would provide a minimal amount of maintenance to keep the units available in case of future capacity shortages. PGUE believes these cold-standby units should be counted as firm capacity. The incremental cost of these plant life extensions would be primarily in the form of maintenance and fuel costs rather than capital costs. No information is available for these costs, however. As a proxy for the present-value cost of keeping these units in cold-standby status, the cost of life extension is treated as a capital cost equal to the cost of a combustion turbine. Accurate combustion turbine costs are readily available and they would represent the upper limit PG&E would be willing to pay for extended-life units. If oil-steam life extension cost more than a combustion turbine, PG&E would just build combustion turbines and retire the oil-steam units. PG&E considers the cost of a combustion turbine to be \$320/kW (\$1987) (PG&E, 1986c). For the purposes of computing the required revenue for the oil-steam refurbishments using LMSTM's financial

[11] The 140 MW Geysers Geothermal Unit #22 is planned for 1995.

submodel, we assume that the oil-steam refurbishments last 39 years and require a 5 year lead time. These assumptions are consistent with those for other oil-steam units in the supply plan.

VI. THERMAL ENERGY STORAGE

In this section, we introduce thermal energy storage in commercial office buildings as a demand-side alternative to conventional supply resources for the PG&E system. We first introduce the technology of TES. We then estimate the size and shape of the demand impact if TES were adopted on a wide scale in commercial office buildings over the next ten years. Finally, we examine the impacts of TES on PG&E-system generation and economics.

1. Introduction to Thermal Energy Storage

Thermal energy storage is a technology designed to flatten loads in buildings and industrial process. While TES has been installed in various types of commercial buildings and industrial processes in the PG&E area, we will focus on the use of TES in commercial office buildings. Limited resources and data will permit us only to estimate the load shape impacts in this type of TES application.

Rather than cool a building directly from a chiller, TES systems use ice or chilled water produced during the night. TES systems have existed for most of this century, but they were traditionally used for highly variable cooling loads that would otherwise require large and expensive air conditioning systems. The wider adoption of TES systems only began in the late 1970's and 1980's in response to increased peak power prices by utilities (Lihach, 1983). Flattening commercial loads is beneficial to both the commercial customer and the utility. Medium and large commercial customers can benefit because they pay higher energy and demand charges during peak hours--hours when cooling loads are typically high. By producing the ice or chilled water at night, commercial customers can substantially lower their utility bills. The cost to the TES adopter is the incremental cost of adding a storage system and other equipment necessary to make the storage work with an air conditioning system (e.g., a colder-temperature chiller, extra fans, and extra controls). A utility like PG&E benefits from TES because the marginal cost of production for PG&E increases during the daytime. By shifting load to off-peak periods, PG&E will realize reduced fuel costs. Also, if there is a need for additional capacity in the future, TES can help defer its construction. In general, TES does *not* reduce kWh sales to the utility. Rather, kWh sales are shifted from one period of the day to another. Because TES adopters are usually on time-of-use (TOU) rates, utility revenues usually fall as a result of TES.

There are two general design strategies for TES (RCF, 1984). In the first strategy, known as *full storage,* cooling loads are completely eliminated during the peak period. This load shift is achieved by installing enough storage so that the entire cooling load of the peak period can be met using ice or chilled water produced during the night. Such a strategy maximizes on-peak energy and power savings but requires the commercial customer to have a relatively large storage system. The second strategy is known as *partial storage.* Partial-storage systems are designed to meet the peak cooling load with a combination of cold-storage and the existing chiller. The utility bill savings from a partial-storage system are less than from a full storage system, but the partial-storage strategy requires less investment because less storage capacity is needed and smaller chillers are adequate. In addition, partial-storage systems, if designed and operated correctly, use less energy than full-storage systems. Energy savings from partial-storage systems are possible because their smaller chillers tend to operate very efficiently due to high load factors. Because of these advantages, we assume that partial-storage systems will prove to be more economic to TES adopters in the future and, thus, will be the dominant TES strategy adopted in the future.

The information necessary to model the impact of TES may be separated into two general parts. First, it is necessary to know how much TES could be adopted in the PG&E system during the simulation period (the next 20 to 30 years). Second, given a set of TES adopters, it is necessary to know the impact of TES on their hourly loads. Both types of information are estimated below.

2. Estimation of TES Market Size

The purpose of this section is to provide a plausible forecast of TES adoption in commercial office buildings in the PG&E service territory. We will measure adoption in terms of its ability to reduce demand on the extreme summer daytype. Any forecast of the adoption of a new technology is uncertain. The following summarizes the limited amount of research which has been conducted to forecast the potential for TES. The potential for TES depends greatly on the number of customer types that are considered for adoption. TES can be used in both the commercial and industrial sectors and within each sector there are many different types of buildings and processes to consider. Thus, it is of no surprise that the scope of TES forecasts varies greatly. This study is concerned primarily with the impact of TES in commercial office buildings. Thus, we will attempt to take existing forecasts and translate them into a forecast for office buildings in the PG&E territory.

Lann and Riall (1986) used one of the largest commercial building data bases for the United States and estimated the potential impact of TES for each of 10 regions in the United States. One of their regions, Region 9, consists of California, Arizona, and Nevada. Their TES-impact estimate was intended to be an informal estimate of the penetration that could be achieved by utilities if they strongly marketed TES and provided incentives. Lann and Riall estimate that the cumulative peak-load impact for their Region 9 in the year 2000 was 1,005 MW in office buildings and 958 MW in all other types of commercial buildings. Because PG&E sells approximately 21% of the electricity consumed by office buildings in Region 9 and has approximately 22% of the region's commercial floor-stock, it is reasonable to assume that the impact to PG&E would be approximately 22% of the impact on Region 9.[12] Thus, using Lann and Riall's study, the total potential peak-load reduction in the PG&E service territory from TES is 221 MW in office buildings and 430 MW in all types of commercial buildings.

Science Applications International Corporation (SAI, 1986) prepared a TES market penetration study for Southern California Edison (SCE). SAI estimated the TES adoption that would be "economically attractive" to SCE customers if the utility offered an incentive of $200 per peak kW avoided. Their range of cumulative potential in the year 2000 was 72 to 98 MW for *both* SCE's commercial and industrial sectors. How would this potential translate to an estimate of the potential for office buildings in the PG&E territory? Roughly speaking, SCE's market size is comparable to PG&E's. In 1985, SCE's kWh sales to the commercial and industrial sector were almost identical in total size to PG&E's (EIA, 1987).[13] Thus, SCE's market size is

[12] Lann and Riall show floor-stock and electric energy sales for 1983 for Region 9 on page B-2. Using PG&E's 1985 Class Load Study (PG&E, 1987a, 4-2) and PG&E's 1982 Commercial Energy Use Survey (PG&E, 1985b, 3-6) it is possible to get estimates of PG&E's electricity sales and commercial floor-stock for 1985. Based on these numbers, PG&E's electricity sales to office buildings were 21% of Region 9's. PG&E office building floor-stock is 25% of Region 9's and its floor-stock of all commercial building types (using a definition for "commercial" that is consistent with Lann and Riall) is 22% of Region 9's.

[13] A more accurate comparison would have to take into account the fact that the climate of SCE's territory is hotter than PG&E's and the end-use mix of SCE's commercial and industrial sectors is very different from PG&E's.

roughly comparable to PG&E's. SAI considered TES adoption in both commercial and industrial applications, however, while Lann and Riall considered only commercial applications. Thus, a similar methodology and assumptions applied to the PG&E territory would result in a very small potential for commercial office buildings: on the order of tens of MW. The reason SAI's estimate is lower is that SAI made more conservative estimates of which types of commercial and industrial customers would potentially adopt TES and, for the types it considered, used much lower penetration rates.

A "back-of-the-envelope" estimate to the potential of TES in office buildings may be made by examining PG&E floor-stock data. In 1982, there was 36.6 million m^2 (393 million ft^2) of office building floor-stock. According to a recent PG&E forecast, this floor-stock is expected to grow to 51.5 m^2 by 1996 and 61.0 m^2 by 2003.[14] The chiller of an office building in the PG&E territory draws approximately 25.8 W/m^2 (2.4 W/ft^2) during peak hours.[15] Thus, office building air conditioning will account for approximately 1,330 and 1,575 MW of peak load by 1996 and 2003, respectively. If 25% of all buildings had partial TES systems that reduced peak load by 60%,[16] the peak savings to the system would be 200 MW in 1996. This estimate is for commercial office buildings in the PG&E territory only.

These two studies and the back-of-the-envelope estimate indicate that there are large uncertainties in estimating TES potential in the PG&E service territory. The potential appears to be on the order of hundreds of MW. For our case study, it is assumed that the program grows to a size of 200 MW avoided peak demand by 1996. While additional potential exists after 1996, it is ignored because our methodology provides more accurate results the earlier the technology is adopted. Adding the avoided transmission losses to our chosen program results in an ultimate load impact of 215 MW in 1996. This impact would be approximately 1% of the system peak generation in both 1996 and 2003.

3. Estimation of TES Load-Shape Impacts

In Section VI.2 we presented estimates of the potential peak-load impact of TES in commercial office buildings. We will now estimate how TES affects loads in all the other hours of the year. In LMSTM, the entire year is compressed into 16 typical daytypes, so the task is to find the hourly impact of TES on these daytypes. Our analysis focuses on the load impact of TES in office buildings.

The general method we use to estimate the load-shape impacts is summarized as follows. For the PG&E territory, a "typical" medium-sized (4,650 m^2, 50,000 ft^2) commercial office building is simulated to estimate the cooling loads in five representative cities in the PG&E territory. The buildings are simulated using DOE-2.1 These cooling loads are sorted into 16 groups that are appropriate for the LMSTM daytype definitions used in this model. A simple algorithm

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Also, SCE has different rates than PG&E. The effect of these differences would probably result in a lower TES potential for PG&E (using SAI's methodology and general assumptions).

14 The forecasted growth rate for office buildings for 1982 to 2007 is 2.45%/year. Information from Mike Robinson, personal communication, PG&E Economics and Forecasting, April 9, 1987.

15 The peak cooling load for the typical PG&E building described in Section VI.3.d is 95 tons. Normalizing for floor area and assuming a coefficient of performance (COP) of 2.8, this peak cooling load is translates into an electrical load of 25.8 W/m^2 Also, a similar estimate of 21.5 W/m^2 peak cooling electric load is reported by Lihach (1983), p. 10.

16 Section VI.3.c shows that a partial storage system reduced peak summer consumption by approximately 60%.

is used to estimate the *change* in cooling load that results from adding storage-priority partial-storage systems to each of the five representative buildings. These load shape changes for the five buildings are averaged to produce a load-shape impact that is representative for the entire PG&E service territory. The load shape changes for this "composite" building is then translated into the energy use ratios (EUR's) and relative load shapes required by LMSTM.

a) Typical-Building Simulation

Very little measured data on the performance of TES systems in California exist. PG&E is currently conducting a performance-monitoring program for a subset of participants in its TES incentive program. However, data from this monitoring study are not yet available. We must, then, resort to engineering estimates of what TES is likely to do to PG&E's system loads. To estimate the impact of a large-scale adoption of partial-storage TES systems in commercial buildings, we simulate the cooling load of a typical medium-sized (4,650 m^2) commercial building[17] in five cities that are representative of the entire PG&E service territory. The cities simulated are Oakland, Red Bluff, Sacramento, San Jose, and Santa Rosa.[18]

The buildings are simulated using DOE-2.1 (Curtis *et al.*, 1984). DOE-2.1 is a detailed model that simulates a detailed representation of a building through a year of hourly weather data. The model produces estimates of hourly end-use loads, including cooling loads. These hourly loads are typically measured in the U.S. in units of tons.[19] We obtain estimates of the hourly cooling loads assuming these buildings have a typical one-shift-per-day occupancy schedule and are not occupied on the weekend. For each typical building, 8,760 cooling loads are produced. A significant problem in the interpretation of this data results from their size; a logical way to aggregate the loads is needed. Because of our chosen occupancy schedule and the daytime weather, the large majority of loads occur during the period of 6 a.m. to 6 p.m. (some early morning loads occur in order to "pre-cool" the building). Also, PG&E's summer demand period occurs from noon to 6 p.m. on weekdays. Thus, a reasonable way to aggregate the hourly loads is to group the loads into a morning period (6 a.m. to noon) and a peak period (noon to 6 p.m.). Once this aggregation is done, cooling loads for each building may be characterized by 3 numbers (measured in ton-hrs) for each day of the year: total load, morning load, and afternoon load. Cooling loads may be further aggregated by averaging the daily loads of similar magnitudes. This is done by sorting total daily loads in each of the seasons into many groups or "bins." The loads in each of these bins are then averaged and the frequency of loads in each bin is noted.

The results of this aggregation process are shown for a sample city, Oakland, in Table VI.1. Columns 1 and 2 of Table VI.1 show the lower and upper bounds, respectively, of each of the bins. Columns 3 through 14 of the table show the following for the four LMSTM seasons: the number of days with total cooling loads that fall within the bin range, the average morning load of each of the bins, and the average afternoon load of each of the bins.[20] The table demonstrates

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[17] The building simulated is commonly called the ASHRAE-90 building. Its characteristics are described in Battelle Pacific Northwest Labs (1983).

[18] The impact of each of these cities will be multiplied by weights appropriate for the TES potential that exists in their climate areas. The weight for Sacramento will *not* include potential TES installations in the SMUD service territory.

[19] A ton is a rate of cooling by refrigeration equipment equivalent to the cooling achieved from melting one ton of ice over a 24 hour period. It is equivalent to 3.52 kW or 12,000 Btus/hour.

[20] The sum of a day's morning and afternoon loads does not always fall within the day's bin range because of pre-cooling loads that occur before 6 a.m.

that buildings have a wide variation in cooling loads. For example, Table VI.1 shows that in the Spring (May - June) the typical building in Oakland has two days with cooling loads totaling more than 550 ton-hours. Twenty-nine days have daily cooling loads ranging from 100 to 250 ton-hours, and there are 19 days with loads less than 50 ton-hours/day. The variation in loads is caused mainly by variation in temperature and insolation. Days falling in the smallest bin (0 to 50 ton-hours/day), however, are weekend days when the chiller is turned off regardless of the weather.

Table VI.1

Building Cooling Loads Sorted by Season and Daily Magnitude

Building: ASHRAE-90 Typical 4,650 m^2 Office Building
Weather Tape: RCTZ03 Oakland
765 ton-hrs per day is the max (design) cooling load
0.251 is the fraction of PG&E territory this city represents

1	2	3	4	5	6	7	8	9	10	11	12	13	14
Bin Dimensions		Winter	Cooling Load		Spring	Cooling Load		Summer	Cooling Load		Fall	Cooling Load	
Min			6 a.m.-N	N-6p.m.		6 a.m.-N	N-6p.m.		6 a.m.-N	N-6p.m.		6 a.m.-N	N-6p.m.
(ton-hrs/day)		Days	(ton-hrs)	(ton-hrs)	Days	(ton-hrs)	(ton-hrs)	Days	(ton-hrs)	(ton-hrs)	Days	(ton-hrs)	(ton-hrs)
800.000	850.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
750.000	800.000	0.000	0.000	0.000	1.000	285.000	480.000	0.000	0.000	0.000	0.000	0.000	0.000
700.000	750.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
650.000	700.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
600.000	650.000	0.000	0.000	0.000	0.000	0.000	0.000	2.000	179.000	430.000	0.000	0.000	0.000
550.000	600.000	1.000	116.000	372.000	1.000	146.000	434.000	2.000	153.000	416.000	0.000	0.000	0.000
500.000	550.000	0.000	0.000	0.000	0.000	0.000	0.000	3.000	164.000	360.000	1.000	127.000	380.000
450.000	500.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000	92.000	378.000	1.000	145.000	328.000
400.000	450.000	4.000	62.000	277.000	2.000	123.000	316.000	8.000	105.000	320.000	2.000	93.000	285.000
350.000	400.000	1.000	53.000	293.000	3.000	107.000	263.000	10.000	91.000	281.000	0.000	0.000	0.000
300.000	350.000	2.000	33.000	243.000	3.000	60.000	278.000	10.000	85.000	236.000	2.000	66.000	226.000
250.000	300.000	1.000	41.000	221.000	2.000	54.000	230.000	4.000	60.000	218.000	4.000	67.000	167.000
200.000	250.000	3.000	34.000	126.000	8.000	48.000	175.000	11.000	57.000	165.000	8.000	42.000	136.000
150.000	200.000	8.000	22.000	131.000	10.000	42.000	133.000	8.000	43.000	137.000	12.000	28.000	110.000
100.000	150.000	13.000	16.000	89.000	11.000	29.000	93.000	4.000	37.000	90.000	11.000	20.000	79.000
50.000	100.000	27.000	6.000	50.000	1.000	29.000	70.000	2.000	32.000	58.000	21.000	10.000	48.000
0.000	50.000	60.000	1.000	12.000	19.000	0.000	0.000	27.000	0.000	0.000	30.000	1.000	5.000
Sums:		120			61			92			92		

b) Aggregation of Hourly Load-Data into 16 Daytypes

For every season, LMSTM simulates dispatch for four days. These days are chosen so as to accurately capture the variation of PG&E *system* loads. The savings from TES must also be distilled into four daytypes per season. An important question is how to aggregate the building loads into the four daytypes that are defined for the purposes of describing the PG&E system loads. If PG&E system loads were uncorrelated with building loads, the aggregation would be easy: for each daytype, the cooling load would simply be the season's mean cooling load. However, we assume that building cooling loads are highly correlated with PG&E system loads. Thus, if the extreme summer daytype represents the highest four daily system loads of the summer season, we assume that the loads of our typical buildings have their four highest daily loads on the same daytype. This assumption likely overestimates the correlation between building loads and system loads (especially in the winter season), but we keep the assumption because we know a strong correlation exists and we do not have any more information which could help us estimate the relationship more accurately.

The daytype fractions that we created to describe the PG&E system loads (Kahn, et al., 1987) are reproduced in Table VI.2. Our cooling loads are split according to these fractions. Because our daily total cooling loads are already sorted according to size for each season in Table VI.1, making the splits is easy. As an example of how this grouping is performed, consider the summer extreme daytype. Table VI.2 shows that this daytype represents the highest

4.35% of loads in that season. This is equivalent to the top four days of the season. An examination of the summer cooling loads shown in Table VI.1 shows that the average morning and afternoon loads of these top four days are 166 and 423 ton-hours, respectively. The results of this aggregation method for all 16 daytypes are shown in Table VI.3. For each daytype, the representative morning and afternoon building cooling load is shown.

Table VI.2

LMSTM Daytype Fractions (.%) (for each daytype and cumulative)

Daytype #	Winter		Spring		Summer		Fall	
4	0.05	1.000	0.0491	1.000	0.0435	1.000	0.0652	1.000
3	0.3167	0.950	0.0492	0.951	0.1522	0.957	0.3696	0.935
2	0.325	0.633	0.5738	0.902	0.4891	0.804	0.2391	0.565
1	0.3083	0.308	0.3279	0.328	0.3152	0.315	0.3261	0.326

Table VI.3

Results of Typical Building in this City: Daytype Loads (ton-hrs)

Daytype	Winter		Spring		Summer		Fall	
#	6a.m.-N	N-6p.m.	6a.m.-N	N-6p.m.	6a.m.-N	N-6p.m.	6a.m.-N	N-6p.m.
4	69.50	295.50	215.50	457.00	166.00	423.00	98.33	288.33
3	21.96	121.85	113.40	284.20	118.67	334.83	33.14	112.71
2	6.00	50.00	41.50	148.44	66.36	198.15	10.00	48.00
1	1.00	12.00	1.45	3.50	2.21	4.00	1.00	5.00
Avg:	12.69	73.32	40.45	122.74	58.44	167.54	21.38	73.57

c) Partial-Storage Model

The amount of load a partial storage system would save depends not only on the load shapes (estimated above) but on the amount of storage. The amount of storage a TES adopter would install in a building depends on the year's maximum or "design" load. The following describes how to estimate the size a partial storage system based on the design load. The method used is adopted from Warren (1986).

On the hottest day of the year, a chiller on a partial storage system should run all day and all night. At night, the system makes as much ice as it can and both the ice and the chiller are used fully to meet the daytime cooling load. For the sample cooling load data shown in Table VI.1, the maximum daily cooling load is 765 ton-hrs. The average cooling load for the design day is thus 32 tons (= 765/24). We assume that the chiller is dedicated to making ice 12 hours of the day and directly meets cooling load with chilled water 12 hours of the day. When the chiller makes ice, its capacity is less than the nominal capacity. Assuming that the ice-making capacity is 0.67 of the nominal capacity, the required minimum nominal capacity for our chiller is 38 tons. The storage must be large enough to hold all the ice produced on the design day. Multiplying the ice-making capacity of 25 tons (= 38 * 0.67) by 12 hours results in a minimum storage size of 307 ton-hrs. The top of Table VI.4 summarizes the sizing of the partial storage TES system for our example city, Oakland.

Table VI.4 shows the energy that is saved as a result of the partial storage system. For each daytype, the cooling load saved is shown for both the morning and the afternoon. The units of Table VI.4 are in ton-hours of load saved.

Table VI.4

Summary of Parameters for Sizing Storage in a Commercial Building in Oakland

Hours of Chilling Water (Day):	12
Hours of Making Ice (Night):	12
Ice-making Capacity (.% of nominal)	0.67
Daytime (Nominal) Chill. Cap. (tons)	38
Storage Size (ton-hours)	307

Savings from TES (ton-hrs) for a Commercial Building in Oakland

Daytype	Winter		Spring		Summer		Fall	
#	6a.m.-N	N-6p.m.	6a.m.-N	N-6p.m.	6a.m.-N	N-6p.m.	6a.m.-N	N-6p.m.
4	0.00	295.50	0.00	306.92	0.00	306.92	0.00	288.33
3	0.00	121.85	0.00	284.20	0.00	306.92	0.00	112.71
2	0.00	50.00	0.00	148.44	0.00	198.15	0.00	48.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

The TES operating rules that resulted in the savings shown in Table VI.4 are summarized as follows. Once a storage system is installed, we assume that the building owner operates the system as economically as possible. This control strategy is known as a *storage priority control* (Warren, 1986). Our storage system is set to maximize the amount of load shifted in the afternoon, the time when energy and capacity are most expensive. For all weekday daytypes, the storage is used to meet any morning load that cannot be met by the chiller alone. This is done by dividing the morning cooling load by 6 hours and subtracting the capacity of the chiller. If the remaining load is positive, it must be met by cold storage. The savings during this period is simply the amount of cold storage used. In the afternoon, the remaining storage is used to shift load to the maximum extent possible. If the load is less than the remaining storage, the savings is equal to the load. If the load is greater than the remaining storage, the savings is equal to the remaining storage.

The results of this control strategy on weekday daytypes are surprising. Because morning cooling loads on the extreme summer and spring days often use up a large fraction of the stored ice, the afternoon load savings on these extreme days can be *less* than the savings seen on the peak and normal daytypes of the same season (this result is not evident for Oakland, but is evident for all of the other cities examined). The surprising characteristics of the savings from TES using this control strategy are discussed further in Section VI.3.e.

We assume that the system does not operate on weekends and holidays. Thus, the savings for these daytypes are all zero.

d) Extrapolating From Typical Buildings to a Representative Building for the PG&E Territory

Because the performance of a storage system depends heavily on the size of the building's storage, it is necessary to estimate the storage savings for each of our five typical cities. Once this is done, we aggregate the impacts into one impact that is meaningful for the entire PG&E territory.

The representative fractions, or weights assigned to each city are determined as follows: Each city is assigned a region (defined by a set of PG&E divisions) that it represents in terms of climate.[21] The fraction of future TES adoptions in each region is set equal to the fraction of participation observed in PG&E's TES incentive program. From April 1985 to December 1986, 57

[21] CEC climate zones are used to assist the assigning of PG&E divisions to typical cities.

developers applied for incentives for installing TES. Participation in the program is weighted by the floor area of each development. Table VI.5 shows the fraction of TES-participant floor-stock associated with each of the five typical cities.[22]

Table VI.5
TES Adopters by PG&E Territory

Typical City	Corresponding PG&E Division	Fraction of Total Floor-stock Adopting TES
Red Bluff	D, F, T, W	0.444
Oakland	J, R	0.251
Sacramento*	P, X, H	0.119
Santa Rosa	N	0.073
San Jose	B, V	0.113
Total		1.000

*Sacramento fraction does not include adopters in SMUD territory

Not surprisingly, the table shows that adopters were predominantly from the hot Central Valley; 56% of adoption took place in regions represented by Red Bluff and Sacramento. Interestingly, according to PG&E's 1982 Commercial Energy Use Survey (PG&E, 1985b), the fraction of PG&E territory floor-stock in these regions is only 33%. Conversely, Oakland represents the San Francisco Bay Area region which has 39% of total floor-stock, but only 25% of current TES adoption. Thus, adoption is strongly affected by climate.

While the data in Table VI.5 have little statistical significance, they are the only market penetration data available for the PG&E territory. Thus, we use the adoption fractions in Table VI.5 to weight the savings from TES. The weighted-average savings from TES for the whole PG&E territory are shown in Table VI.6. The units of Table VI.6 are in ton-hours of saved load for a typical 4,650 m^2 building in the PG&E territory. These numbers may be interpreted directly as EUR's as LMSTM cares only about their relative sizes.

Table VI.6

Savings from TES (ton-hrs) for a Typical Commercial Building in the PG&E Territory:

	Winter		Spring		Summer		Fall	
Daytype #	6 a.m.-N	N-6p.m.	6a.m.-N	N-6p.m.	6a.m.-N	N-6p.m.	6a.m.-N	N-6p.m.
4	0.00	322.11	82.45	357.12	91.42	348.15	0.00	396.46
3	0.00	134.73	17.67	416.20	13.31	426.26	0.00	154.47
2	0.00	52.19	0.00	289.49	0.00	379.66	0.00	32.86
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

22 All but 15 of these participants reported the floor area of their development. Participants not reporting floor area are assumed to have a floor area equal to the average floor area of the reporting sample. Note that not all participants used TES for commercial buildings. Many participants are installing systems in schools and food-processing facilities. Thus, this data should be considered a rough estimate of future TES penetration.

e) The Shapes of the Incremental TES Loads

The *shapes* of these energy savings are based on a simple set of assumptions. These load shapes are graphed in Figures VI.1 - VI.4. for the winter, spring, summer, and fall seasons, respectively. During the day, load savings start either at the 7th or 12th hour of the day, depending on whether there is morning cooling load to be saved.[23] The last hour of load savings is on the 18th hour. Savings in the morning or the afternoon are generally flat except that they "ramp-up" or "down" on the 7th, 12th, and 18th hour.

The shapes at night are also flat with ramps in the first and last hours. The length of the filling at night depends on the amount of ice that needs to be made. In general, the filling is done in the early morning because earlier LMSTM runs show that this is the time when marginal costs are lowest.

Because we are modeling partial-storage TES systems, our TES system operates in some unexpected ways. In the summer season (shown in Figure VI.3), the highest on-peak load savings are not in the extreme day but on the peak daytype. This is because on the extreme day the storage system must meet morning cooling loads and the remaining amount of storage is just able to reduce the peak demand 200 MW. On the peak daytype, however, very little morning cooling load needs to be met and 245 MW of afternoon load is saved. The normal daytype also saves more load in the afternoon than the extreme. In this case load savings are not limited by the amount of storage, but on the amount of load. This may be seen by examining the evening filling. On the extreme and peak days, ice is made all night long (12 hours). On the normal daytype, ice is only made for 10 hours. Because the chiller makes ice all night on the extreme and peak daytypes, the partial-storage system will add load to the system when the marginal costs are high. Summer marginal costs produced by LMSTM stay high until the 10th or 11th hour of the day.

Similar load shapes are evident in the spring (Figure VI.2). The weather in the spring season (May and June) has many hot days in it. Thus, the load shapes for extreme and peak days are similar between spring and summer. The load savings on the normal daytype, however, are much lower in the spring than in the summer.

Fall (Figure VI.4) is characterized by very hot afternoons on the extreme daytype that result in 228 MW of savings from TES. Loads on the peak and normal daytypes are very low, however. Load savings in the winter (Figure VI.1) are the lowest of any season, but savings on the extreme day still reach 185 MW. In the fall and winter the demand charge is relatively low so the incentive to save afternoon load in these seasons is much less. There is still an incentive to shift energy, however, so we assume that once a TES system is installed, it is operated in every season. Thus, a real TES system might not reserve all its ice for the afternoon in the fall and winter, but the magnitudes of the load shifts would still be similar to those presented in the figures.

f) Estimation of the Revenue Loss Associated with a Kilowatt Reduction in Demand by TES

Given a kW reduction of summer extreme peak load via TES, what is the yearly utility-bill savings (or utility revenue loss) that results? An answer to this question may be estimated by examining the load shapes presented above and by examining energy and power prices. We

[23] For this analysis of TES, we assume that hour N represents the average load from (N-1):00 to N:00. For example, hour 12 represents the average load from 11:00 to 12:00.

assume that all TES adopters pay for energy and power according to PG&E's large-customer TOU tariff (PG&E, 1987b). Currently, PG&E charges TOU customers for demand on a monthly, non-ratcheted basis. Thus, every month that TES reduces a building's peak demand results in money saved by the building owner. In the summer, the demand charge for demand during the peak period (noon to 6 p.m.) is \$10.47/kW/month.[24] In the winter, a TOU customer's peak demand is charged \$2.72/kW/month.[25] Table VI.7 shows peak demand savings normalized to the savings on the extreme summer daytype (column C) and the applicable demand charges (column E) for each LMSTM season. Note that the demand savings in all seasons is quite high relative to the summer season. For example, TES can reduce 0.92 kW of air conditioning loads on the winter extreme daytype for every kW of reduction that occurs on the extreme summer daytype. If every kW of cooling load savings results in a kW of meter demand savings, the savings per month (relative to a kW reduction in the summer) will simply be the product of column C and E. However, it is questionable whether a kW of reduced cooling load always translates into a kW reduction at the building's meter. It is quite possible to reduce cooling loads in the winter but to have the building's peak unchanged because it is dominated by, for example, lighting loads. Thus, we multiply the product of columns C and E with a factor (column D) to account for how much cooling demand savings affect meter demand savings. This factor is 1.0 in the spring and summer, but only 0.5 in the fall and winter. The total seasonal demand-charge savings are shown in column F. The total for the year, \$62.57, is quite large and is the dominant source of savings to the TES adopter paying PG&E rates.

In addition to saving on demand charges, in all seasons there is approximately a 3¢/kWh differential between on-peak and off-peak energy prices. The amount of energy that is shifted per month per kW of demand in a month may be computed from the EUR's derived above and is shown in column G.[26] We assume that even if a TES system does not save much on the demand charge (as is the case in the winter), it is still operated to achieve the energy charge savings. The energy bill savings per season is found as the product of the number of months (column B), the energy shifted per monthly kW (column G), the price differential (column H), and the ratio of seasonal peak demand to summer peak demand (column C). The total revenue loss may be found by summing the demand- and energy-charge savings (F + I). Our estimate is \$93/avoided-kW/year. This is a large amount of savings. The present value of such a stream of savings for 20 years using a 6% real discount rate is approximately \$1,100/avoided-kW. Obviously, the incentive for shifting load on the PG&E system is very large.

4. Results

In this section, our estimate of the impact of TES on the PG&E system is summarized using three LMSTM runs. These runs are numbered 115, 120, and 129. Run #115 is the base case. It is to this case that most policy cases are compared. Run #120 incorporates a TES program that

[24] This demand charge is almost 6 times greater than the demand charge in effect in 1986. Before the general rate case in 1986, the peak demand charge during the summer season for medium and large customers on TOU rates was \$1.70/kW/month. Also note that our definition of seasons does not allow for an exact correspondence between rate seasons currently used by PG&E and seasons used in our model of PG&E. PG&E's summer season is May through October. Our definition of the summer rate season is May through September (our LMSTM spring and summer seasons).

[25] In the winter season, the demand charge is based on the highest demand in any hour of the day.

[26] The reduction in utility bill savings due to cycling losses is ignored.

Table VI.7

Estimated Revenue Loss from TES Using Current PG&E Rates
($/Peak-kW-Avoided)

All dollars are 1987 dollars
Rate Information is from PG&E rate tariff E-20 (PG&E, 1987)
It is assumed that all Commercial TES adopters are on E-20

A	B	C	D	E	F	G	H	I
LMSTM Period	No. of Months/ Season	Cooling Demand Normalized to Avoid. Summer Demand (.%)	Frac. of Season Demand Savings Realized on Bill#	Demand Charge ($/kW /Month) (.%)	Demand Charge Savings ($)	Energy Shifted per kW Avoided* (kWh/kW /Month)	Off-Peak Price Diff'nce ($/kWh)	Typical Peak-to Energy Charge Savings ($)
Winter	4	0.925	0.500	2.72	5.03	42	0.034	5.28
Spring	2	1.026	1.000	10.47	21.48	104	0.032	6.83
Summer	3	1.000	1.000	10.47	31.41	140	0.032	13.44
Fall	3	1.139	0.500	2.72	4.65	42	0.034	4.88
					-------			--------
Year					62.57			30.43

Total Yearly Savings ($/Peak-kW-Avoided/Year) F + I: 93.00

* Energy Shifted per kWh Avoided is calculated from TES EUR's and load shapes
# It is assumed that only half of the demand reduction of TES in the Winter and Fall is realized by customers due to other building loads surpassing AC loads. However, TES is operated to maximum extent allowed by loads because of the energy cost savings available in the Winter and Fall.

reduces the summer peak demand by 200 MW in 1996. Run #120 also defers a corresponding amount of oil-fired steam capacity. Run #120 is our best estimate of the impacts of a TES program aggressively marketed by PG&E. Run #129 is the same as #120 except the size of the TES program and the supply-side deferrals are increased by approximately a factor of 6. The magnitude of the demand-side changes in run #129 is unrealistic but the run is performed to see how the value of a demand-side program changes as it increases in size.

First, we examine the effect of the TES on PG&E loads. Second, we examine the changes in the supply-side as a result of the three TES program simulations. Third, we estimate the value of the most plausible TES program simulated, run #120.

a) Demand-Side Impacts

Using the load shapes and energy use ratios (EUR's) developed in Section VI.3, run #120 reduced the peak system load 215 MW in the LMSTM summer season (July-September) by 1996. The system load reduction is 15 MW larger than the demand reduction proposed in Section VI.2 due to transmission-loss savings. The hourly loads for the extreme day of the summer season are shown in Figure VI.5 for the base-case and the two TES cases. TES also saves loads on other daytypes. The TES program modeled in run #120 reduces the system peak by 220 MW in the spring (May-June). As noted in Section VI.3.e, the peak savings in the spring season is larger than in the summer due to relatively low morning cooling loads that allow more storage to be reserved for peak load reduction.

In the summer, the system peak occurs between 3 and 4 p.m. and in the spring it occurs between 2 and 3 p.m. Because these peaks coincide with the time of the day that TES saves the most, all of the demand reduction translates into savings for the utility. In the fall and winter seasons, the system peaks occur between 5 and 6 p.m. At this time, the ability of TES to reduce building loads is substantially reduced. As a result, TES reduces demand only 122 MW in the fall (October-December) and 100 MW in the winter (January-April).

The TES program modeled in run #129 is six times larger with respect to the number of participants than run #120. In general, however, the results are not six times as large. On the extreme summer day of 1996, peak loads are reduced 1,167 MW. During the period of noon to 5 p.m., TES reduces load 1,290 MW (which is 6*215 MW). Only 90% of the load reduction is seen by the system because the peak shifts to hour 19 (6 - 7 p.m.), a time when TES *adds* loads. The peak shift of run #129 is shown in Figure VI.5. The peak-shift lasts until 1998. From 1999 on, the entire demand savings of TES benefit the system because increasing demand for energy and decreasing load factors create larger opportunities for system peak shaving.

As described in Section III, the supply-side value of a demand-side program is measured by averaging load impacts over a certain number of highest-load hours. Figure VI.6 shows the average load impact of TES over various amounts of the highest-load hours. The figure shows, surprisingly, that the average load impact of TES initially increases, then decreases, and increases again as the load impacts from the top 1 to 1000 highest loads are averaged. The average impact increases for the first 50 hours because savings on some daytypes (e.g. summer peak and fall extreme) are higher than on the daytype with the highest system loads (summer extreme). The reason for the dip at approximately 200 hours is that TES *adds* load on the high nighttime loads of the extreme and peak days of the summer and spring seasons and to the extreme day of the fall season. Thus, the average load savings are diluted by these load additions.

As noted in Section III, the appropriate period of averaging for PG&E is approximately 150 hours. Figure VI.6 shows that the capacity benefit at 150 hours is 174 MW. In addition to this capacity value, TES should be given a credit for avoiding reserve-margin capacity. Due to the load-adding characteristic of TES, however, a more conservative deferral of 165 MW is made in our LMSTM simulations. In run #129, the demand-side impacts are six times larger and the amount of capacity that we defer is 963 MW.

b) Supply-Side Impacts

Our simulated TES program is set to grow exponentially from a small level in 1989 to its target level of 200 MW by 1996. Tables VI.8 and VI.9 summarize the supply-side impacts of the TES runs for 1996 and 2003. These two years are representative of the period where significant changes occur. The tables show energy production by resource, annual variable operating costs, seasonal- and annual-average marginal costs, and incremental energy rates for all four runs. In addition, the tables show the difference in the results between run #115 and both runs #120 and #129.

These runs demonstrate that TES shifts energy production from expensive oil and gas resources to less-expensive resources. Run #120 reduces oil and gas production by 79 GWh and 88 GWh in 1996 and 2003, respectively. This is a result of the reduced on-peak demand achieved by TES. Because In addition to oil and gas resources, TES reduces imports of non-firm power from the Pacific Northwest (NW Thermal) by 16 GWh in 1996 and 4 GWh in 2003. NW Thermal is priced at approximately 75% of the cost of power generated by PG&E's more-

Table VI.8
Comparison of Supply Submodel Outputs
(Year = 1996)

	Base Case #115	TES & Supply Deferral Case #120	#120 Minus #115	Large TES & Supply Deferral Case #129	#129 Minus #115
Resource		Yearly Production (GWh)			
Nuclear	16,453	16,544	91	16,913	460
Oil & Gas	10,816	10,737	-79	10,320	-496
Geysers	10,462	10,462	0	10,462	0
Other Geo	2,361	2,363	2	2,374	13
EOR QF's	498	500	2	517	19
Other QF's	20,652	20,652	0	20,652	0
Self Genr	3,613	3,613	0	3,613	0
Gen Baseld	280	282	2	292	12
NW Thermal	3,082	3,066	-16	3,101	19
Pumped Stg	1,261	1,224	-37	1,000	-261
Hydro	29,648	29,648	0	29,648	0
Total	99,126	99,091	-35	98,892	-234
		Annual Variable Operating Costs (M$)			
	2475.7	2466.2	-9.5	2431.1	-44.6
LMSTM Period		Avg. of Hourly Marginal Costs (¢/kWh)			
Winter	2.91	2.91	0.00	3.02	0.11
Summer	4.38	4.41	0.03	4.57	0.19
Fall	4.68	4.70	0.02	4.83	0.15
Spring	1.89	1.86	-0.03	1.78	-0.11
Annual Avg	3.56	3.56	0.01	3.66	0.10
		Incremental Energy Rate (Btu/kWh)			
Annual Avg	6,431	6,444	14	6,618	187

efficient oil-steam generating units and is sometimes on the margin when TES shaves loads.

Because TES flattens loads, it may be seen as a competitor to pumped hydroelectric storage. Thus, it is no surprise that pumped storage production decreases 23 GWh and 37 GWh in 1996 and 2003, respectively.

Most of the generation avoided by oil and gas and Northwest thermal is taken up by nuclear units. Nuclear production increases 91 GWh in both 1996 and 2003. In addition, geothermal power, small power produced by enhanced oil recovery facilities (EOR QF's), generic baseload coal all increase as a result of the TES. All of these resources cost less than oil and gas resources.

Table VI.9
Comparison of Supply Submodel Outputs
(Year = 2003)

	Base Case #115	TES & Supply Deferral Case #120	#120 Minus #115	Large TES & Supply Deferral Case #129	#129 Minus #115
Resource			Yearly Production (GWh)		
Nuclear	16,706	16,797	91	17,171	465
Oil & Gas	16,896	16,808	-88	16,304	-492
Geysers	10,462	10,462	0	10,462	0
Other Geo	2,366	2,369	3	2,374	8
EOR QF's	635	639	4	658	23
Other QF's	21,174	21,174	0	21,174	0
Self Genr	6,025	6,025	0	6,025	0
Gen Baseld	303	305	2	318	15
NW Thermal	4,683	4,679	-4	4,746	63
Pumped Stg	1,253	1,230	-23	1,128	-125
Hydro	29,711	29,711	0	29,711	0
Total	110,214	110,199	-15	110,071	-43
		Annual Variable Operating Costs (M$)			
	5428.7	5407.1	-21.6	5330.1	-98.6
LMSTM Period		Avg. of Hourly Marginal Costs (¢/kWh)			
Winter	7.83	7.86	0.03	7.95	0.12
Summer	9.11	9.20	0.09	9.66	0.55
Fall	9.47	9.47	0.00	9.51	0.04
Spring	4.97	4.99	0.02	5.05	0.08
Annual Avg	8.09	8.12	0.04	8.29	0.20
		Incremental Energy Rate (Btu/kWh)			
Annual Avg	7,703	7,737	34	7,895	192

Total electricity generated in both test years decreases as a result of TES. This occurs even though TES demands more energy than the base case. Total generation in the model goes down because reduced use of pumped hydroelectric storage reduces pumping losses. Also, flatter loads reduce commitment requirements on units with minimum blocks. These units sometimes contribute to system losses. Because the reduction in these system losses is greater than the cycling losses of TES (assumed to be 10%), total generation of electricity goes down in all TES cases.

The production results from run #129 show the impact of a TES program that is six times the size of the one modeled in #120. Tables VI.8 and VI.9 show that oil and gas generation decreases 496 GWh in 1996 and 492 GWh in 2003 compared to the base case. This reduction in oil and gas generation is six times greater than the reduction brought about in run #120. Changes in the use of other resources are similar to the changes exhibited in run #120 except that use of Northwest thermal increases rather than decreases. Load is shifted enough in run #129 so that Northwest thermal is used more often to meet nighttime loads. Because Northwest thermal is more expensive than the resources used for filling in run #120 (mostly nuclear), we would expect to see diminishing returns from a TES program of the size in run #129. An examination of the yearly operating-costs, shown in Tables VI.8 and VI.9, shows that savings from run #120 to #129 (both compared to the base case) increase four to five times even though program size increases six times. Thus, the larger-sized program begins to exhibit diminishing returns with respect to its benefit to the utility system.

Tables VI.8 and VI.9 also summarize the average marginal costs for each season and for the entire year. Because TES is not designed to save energy, there should not be large changes in average-seasonal or average-annual marginal costs as a result of the program. Tables VI.8 and VI.9 show that average marginal costs generally increase except for the spring season in 1996 for both runs #120 and #129. The average-hourly seasonal marginal costs in run #120 change are all within 2% of the base case.[27] In run #129, average marginal costs change as much as 6% in a season.

In general, TES should decrease on-peak marginal costs and increase off-peak marginal costs. The result of runs #120 and #129 prove this to be true. The general increase in marginal costs shown in Tables VI.8 and VI.9 are due to off-peak costs rising at a faster rate than on-peak costs. Table VI.10 demonstrates the result that off-peak costs rise faster than on-peak by showing the average hourly marginal costs of the summer weekdays. A period of relatively high marginal costs are sustained during the period of 7 a.m. to 10 p.m. in the summer. Table VI.10 shows that these costs rise much less than the increase during the period of 10 p.m. to 7 a.m. This effect is particularly noticeable for run #129, where on-peak costs decrease 2.5% but off-peak costs rise 34.3%.

Table VI.10
Comparison of Off-Peak and On-Peak Marginal Costs
(LMSTM Summer Weekdays; Season 2, Daytypes 2, 3, & 4; Year = 2003)
(¢/kWh, unless noted otherwise)

Period	Base Case #115	TES Case #120	#120 Rel. to #115	Large TES Case #129	#129 Rel. to #115
10 p.m.-7 a.m.	5.88	6.00	2.0%	7.90	34.3%
7 a.m.-10 p.m.	11.50	11.47	-0.3%	11.21	-2.5%
Summer Weekday Avg.	9.31	9.42	0.3%	9.97	6.1%

The general insensitivity of on-peak marginal costs to lower on-peak demand is unexpected. It is the result of the fact that the marginal cost-curve is flat in the region of peak demands. In other words, the system still has expensive oil and gas resources on the margin even after reducing load 200 or 1200 MW. Even though on-peak marginal costs do not fall very

[27] Because these changes are small, we conclude that the impact of TES on endogenous utility fuel prices to be slight. Therefore, no adjustment of PG&E's QF or geothermal prices--as described in Section III--is necessary.

much, the utility still saves large amounts of money due to the reduced load. Table VI.10 suggests, however, that there are diminishing returns to substituting off-peak power for on-peak power.

The decrease in marginal costs in the spring season of the 1996 test year is primarily due to a decrease in marginal costs in the *weekend* daytype. This at first seems unusual because TES has no effect on weekend demand and the deferred resource is a dispatchable resource on weekends (i.e., it is not must-run). However, the spring season has a large amount of pondage hydroelectric power available. As TES flattens loads on weekdays it presumably leaves more storage hydro for the weekend, thus decreasing weekend marginal costs. While this is a plausible explanation for the decrease in marginal costs in the spring of 1996, it does not explain why spring marginal costs increase by the 2003 test year. By 2003, spring weekend marginal costs are unchanged between the base and policy cases and the increase in seasonal average marginal costs are due to increases on the weekdays. Obviously, the increased availability of storage hydro in the two policy cases no longer reduces marginal costs on the weekends by 2003. This appears to be a result of load growth and decreasing load factors pushing generation above certain cost "thresholds."

The last supply results summarized in Tables VI.8 and VI.9 are the system's average annual incremental energy rate (IER). IER's are an indication of the fraction of oil and gas resources that are on the system's margin. They are useful as a way to measure shifts in resource use over time. The IER in the base case in 1989 is 6,158 Btu/kWh. Tables VI.8 and VI.9 show that the base-case IER increases steadily throughout the simulation period to 6,431 in 1996 and 7,703 in 2003. Thus, the fraction of oil and gas resources on the margin is increasing over time. Over the three test years, however, the IER's in the base case are lower than have been estimated previously for PG&E (Kahn *et al.*, 1987), indicating that non-oil and gas resources are on the margin a large fraction of the time throughout the simulation period. This is primarily a result of the low demand forecast used in these simulations.

c) Value of Demand-Side Program

Run #120 represents the impacts of adding 200 MW of TES to the PG&E system. We will now analyze the economic effects of this scenario relative to the base case. The net benefit of a TES program may be estimated for either the utility, the customer, or society as described in Section III. The following presents the net-benefit from these three perspectives. We perform this analysis with a primary set of assumptions and then perform several sensitivities.

As noted in Section III, the net societal benefit of TES may be measured as the utility's variable- and capital-cost savings minus the incremental cost of installing TES. As mentioned in Section III, we use two methods to value the capacity benefit of the demand-side program. Both methods start by averaging the load impact over a certain number of highest-load hours as a way to approximate their value in units of deferrable supply-side capacity. Also, both methods give the demand-side program a 20% credit for avoiding capacity necessary for the utility's reserve margin. The first method, known as Method 1, simply values the capacity at its "overnight" cost in the years that load savings occur. The second method, known as Method 2, uses the financial model of LMSTM to calculate the stream of revenue-requirement savings that result from deferring a particular supply-side unit. The first method is more transparent and is easier to modify for the purposes of sensitivities (i.e., LMSTM runs are not necessary). Method 2 is a more accurate estimate of the actual revenue-requirement savings that would be realized. We compute the net benefit of TES using both methods. For sensitivities, however, we will value capacity using only the first method.

Table VI.11 shows the net benefit of TES from the perspective of society. All cash flows in this table are put into present-value terms using a discount rate of 10% that accounts for both inflation (5%) and the time-value of money (5%). The table shows values for three time horizons: 1987-2007, 1987-2017, and 1987-2027.

For our primary estimate of the net benefit, we use the results of run #120 compared to the base case, run #115. The utility operating-cost savings are computed as the difference in operating costs between these two runs and are shown in row 1 of Table VI.11. We assume that TES equipment installed by 1996 lasts 21 years. Thus, Table VI.11 shows that the value of the fuel savings grows to a value of $96.5 M as the horizon is increased to 2017.

For both methods of valuing the avoided capacity cost, an overnight capital cost of $320/kW is used. For the purposes of this cost-benefit analysis, we assume that the total deferred capacity is 209 MW.[28] This is computed as the product of the 150-hour average of 174 MW and the 1.2 reserve-margin credit. The capacity value using Method 1 is shown in row 2 of Table VI.11. Method 1 counts the capacity savings as the loads are reduced; this occurs primarily during the years 1990-1996. Thus, the present value to society of $48.6 M is the same for all three horizons presented. Method 2 defers refurbishment of 209 MW of oil-steam capacity in 1996 and the savings are computed as a stream of revenue-requirement savings starting in that year. The capacity value using this method is shown in row 3 of Table VI.11. The capacity value using Method 2 is $86.8, $112.9, and $128.9 M for horizons ending in 2007, 2017, 2027, respectively. From a theoretical viewpoint, the capacity value using the 2027 horizon is the best because it counts the most of the utility's revenue-requirement savings.[29] The ratio of Method 2 to Method 1 is the ratio of present value of the revenue requirements method to the overnight capital cost. Row 4 of Table VI.11 shows that the ratio is as high as 2.65. This ratio is higher than what has been reported elsewhere in the literature.[30]

The incremental cost of TES is $250 per avoided-kW[31] and is paid for by adopters of the technology as it is installed. This cost is assumed to increase at the general rate of inflation (i.e., 0% real) and is shown in row 4 of Table VI.11. Because we assume that all 200 MW of TES is installed by 1996, the present value of the costs is the same for our three time horizons: $36.3 M.

The net benefit of TES to society is simply the sum of the variable- and capital-cost savings minus the incremental cost of TES. Row 5 of Table VI.11 shows the net benefit using Method 1 and row 6 shows the net benefit using Method 2. Using Method 1, the net benefit is $70.0, $108.8, and $108.8 M for time horizons ending in 2007, 2017, and 2027 respectively. The net

[28] This assumption is somewhat inconsistent with the deferral discussed in Section VI.4.b. In our LMSTM runs, only 165 MW were deferred. The capacity values shown here are "scaled-up" to be appropriate for 209 MW of deferral. This was done because we later deemed our initial deferral estimate (165 MW) to be too conservative.

[29] Our cost-benefit program, EVALER, cannot calculate costs or benefits past 2027. Ideally, we would want to count the capacity benefit using Method 2 to 2035 because we modeled the oil-steam refurbishments with a 39 year book life starting in 1996. We do not believe that this creates a large bias, however. EVALER appears to overestimate the capacity savings from Method 2 in years after 2007, so the present value of capacity savings in 2027 is probably close to the *true* value that count all years (1996 to 2035).

[30] Leung and Durning (1978) report a ratio of 1.7 in an example that uses financial parameters similar to ours except for the value chosen for WACC. Leung and Durning used a WACC of 9.0%; we use 10.4%.

[31] The incremental cost of partial-storage TES systems is taken from a range of costs provided by Joyce Yokoe, PG&E Rate Department, May 1987. Similar costs are also reported in Rosenfeld and de la Moriniere (1985).

benefit does not grow as years after 2017 are included because the capital-cost savings are captured by 1996 and the variable-cost savings by 2017. Using Method 2, the benefit of TES for the three horizons is $108.2, $173.1, and $189.1 M. The net benefit using Method 2 keeps increasing as the time horizon is increased because more years of revenue-requirement savings are counted. The larger net benefit using Method 2 is due to the much larger valuation of the avoided capacity. A discussion of the differences in the two methods is contained in Section III.

Table VI.11
Societal Net-Benefit of TES

Run #120 vs. #115
Present Value of Dollar Streams Starting in 1987
Millions of 1987 Dollars
10% Nominal Discount Rate Used

	To 2007	To 2017	To 2027
1. Variable Operating Cost Savings	57.7	96.5	96.5
2. Capital Cost Savings: Method 1	48.6	48.6	48.6
3. Capital Cost Savings: Method 2	86.8	112.9	128.9
4. Ratio of Two Cap. Cost Methods (3/2)	1.50	2.32	2.65
5. Incremental Cost to TES Adopters	36.3	36.3	36.3
6. Net Benefit: w/ Method 1 (1+2-5)	70.0	108.8	108.8
7. Net Benefit: w/ Method 2 (1+3-5)	108.2	173.1	189.1

Next we calculate the net benefit of TES from the perspective of the utility. A summary of the utility net benefit is shown in Table VI.12. As noted in Section III, we calculate the net benefit to the utility as the capital- and fuel-cost savings minus the utility-bill revenue losses and direct incentives (if any).

Sensitivity A in Table VI.12 represents the same set of assumptions used for the societal analysis of Table VI.11 except only Method 1 is used to value the capacity savings and a discount rate of 10.4% is used. This discount rate is equivalent to the pre-tax weighted average cost of capital used in our LMSTM runs. Table VI.12 also shows the cost of direct incentives in present-value terms. This payment is made to the customer at the time of adoption. Since April 1985, PG&E has offered a $200 per avoided-kW incentive for the adoption of TES (PG&E, 1986b).[32] Note that this direct incentive is normalized to the peak demand savings (200 MW) rather than its capacity savings (209 MW). Thus, the cost of direct incentives per unit of capacity avoided by the utility is actually $191 (which is 200 MW/209 MW * $200). Ignored are any administrative program costs to the utility.

Table VI.12 shows that the net benefit to the utility is *negative*. The present-value net *loss* to PG&E using a horizon to 2017 is $80.1 M without incentives and $108.4 M with incentives. The utility loses because the revenue loss from reduced demand (TES adopter utility-bill

[32] As a result of commercial-building developers that participated in PG&E's incentive program from its beginning (April 1985) to December 1986, as much as 16 MW of peak demand will be shifted. Many projects are still under construction, however, so an accurate estimate of the amount of peak shifted is not yet available. Information from Joyce Yokoe, personal communication, PG&E Rate Department, June 1987.

Table VI.12
Utility Net-Benefit of TES

Run #120 vs. #115
Present Value of Dollar Streams 1987 - 2017
Millions of 1987 Dollars
10.4% Nominal Discount Rate Used
Method 1 for valuing capacity benefit

	Sensitivity			
	A	B	C	D
1. Capacity Cost Savings: Method 1	47.4	47.4	107.4	107.4
2. Variable Operating Cost Savings	90.2	90.2	90.2	90.2
3. Revenue Loss from Cust. Bill Savings	217.7	110.1	217.7	169.3
4. Net Revenue Loss (3-2)	127.5	19.8	127.5	79.1
5. Benefit w/o Incentive (1-4)	-80.1	27.6	-20.1	28.3
6. $200/kW Incentive	28.3	28.3	28.3	28.3
7. Benefit w/ $200/kW Incentive (5-6)	-108.4	-0.7	-48.4	0.0

Sensitivities:
A: Primary Case
B: 46% reduction in rev. loss to $50/avoided-kW/year
C: Avoided capacity valued at $725/kW
D: Avoided cap. at $725/kW and 22% red. in rev. loss to $69/avoided-kW/year

savings) is substantially higher than the combined benefit of the capacity savings and the fuel-cost savings. As noted in Section VI.3.f, the revenue-loss per peak kW saved is based on the demand patterns of our simulated office buildings and current PG&E rates. As noted in Section III, we assume that these losses per avoided kW escalate at inflation and the real rise in average rates seen in earlier LMSTM runs. While the net loss to the utility is quite large, it is important to note that the cost savings come from LMSTM but the revenue-loss estimates comes from current rate tariffs (i.e., they are calculated exogenous to LMSTM). It is reasonable to expect that revenue lost from TES would eventually be collected elsewhere due to the nature of regulated-utility ratemaking. Thus, this net loss to the utility should be considered a worst case.

An interesting question is at what rates would the TES program provide a net positive benefit to the utility providing incentives. In sensitivity B of Table VI.12, the revenue loss is reduced 46% to $50 from $93/avoided-kW/year. With this reduction in revenue losses, the utility has a $27.6 M net benefit without incentives and just breaks even with incentives. Thus, given direct incentives, prices on the margin exceed avoided costs by a factor of 1.8 (which is $93/$50).

Based on the discrepancy between the value of avoided capacity using our two methods, it is obvious that our chosen value for this variable is uncertain. While our primary assumption of valuing capacity at $320/kW comes from information provided by PG&E, other research on PG&E has put the value at $725/kW.[33] Sensitivity C of Table VI.12 shows the net benefit to the

[33] Our primary cost assumption comes from PG&E (1986c). ACEEE (1986), page 2-7, reports that the cost of peaking capacity is $670/kW in 1985 dollars. Assuming 4%/year inflation results in $725 in 1987 dollars.

utility assuming that the value of avoided capacity is $725/kW. Even though this value is higher, the net benefit remains negative: -$20.1 M without incentives and -$48.4 M with incentives Only if marginal rates to TES adopters are lowered 26% to $69/avoided-kW does the utility break even (with direct incentives). This sensitivity is labeled D in Table VI.12.

The net benefit to TES adopters is the utility bill savings (utility revenue loss) minus the direct cost of installing TES. This is equivalent to the difference between the societal and utility net benefit. Because the societal benefit is positive and the utility benefit negative, the TES adopter benefit is larger than the societal benefit. Using the assumptions of the societal analysis, the net benefit to consumers is $195 M. Sensitivity B and D, which reduce the utility bill savings, reduce the benefit to the TES adopters. However, the net benefit to TES adopters still remains positive under these sensitivities.

Another uncertain variable in this analysis is the incremental cost of TES systems per kW of avoided peak demand. Because of this uncertainty, an interesting question is: How much is society willing to pay for the demand-side impacts of TES? Table VI.13 presents sensitivities for demonstrating the value of TES to society. Sensitivity A reproduces from Table VI.11 the 30-year societal net benefit of TES using Method 1. Assuming that avoided capacity is valued using Method 1 at $320/kW, the maximum amount that society should be willing to pay for TES may be found by increasing the customer costs until the net benefit for society falls to zero. Sensitivity B shows that society could pay $1,015/avoided-kW via TES before the net benefit would fall below zero. If we assume that avoided supply-side capacity is valued at $725/kW, society should be willing to pay $1,420/avoided-kW. This is shown in sensitivity C. Note that the difference between the value of avoiding supply-side capacity ($320 or $725) and the value of a kW reduction via TES ($1,015 or $1,420) is approximately $690/kW. This value may be interpreted as the present value of fuel savings from TES per kW of avoided demand.

Table VI.13
Sensitivities to Societal Net-Benefit of TES

Run #120 vs. #115
Present Value of Dollar Streams 1987 - 2017
10.0% Nominal Discount Rate Used
Method 1 for valuing capacity benefit

	Sensitivity		
	A	B	C
1. Variable Operating Cost Savings	96.5	96.5	96.5
2. Capital Cost Savings: Method 1	48.6	48.6	110.1
3. Incremental Cost to TES Adopters	36.3	148.0	206.5
4. Net Benefit: w/ Method 1 (1+2-3)	108.8	-2.9	0.1

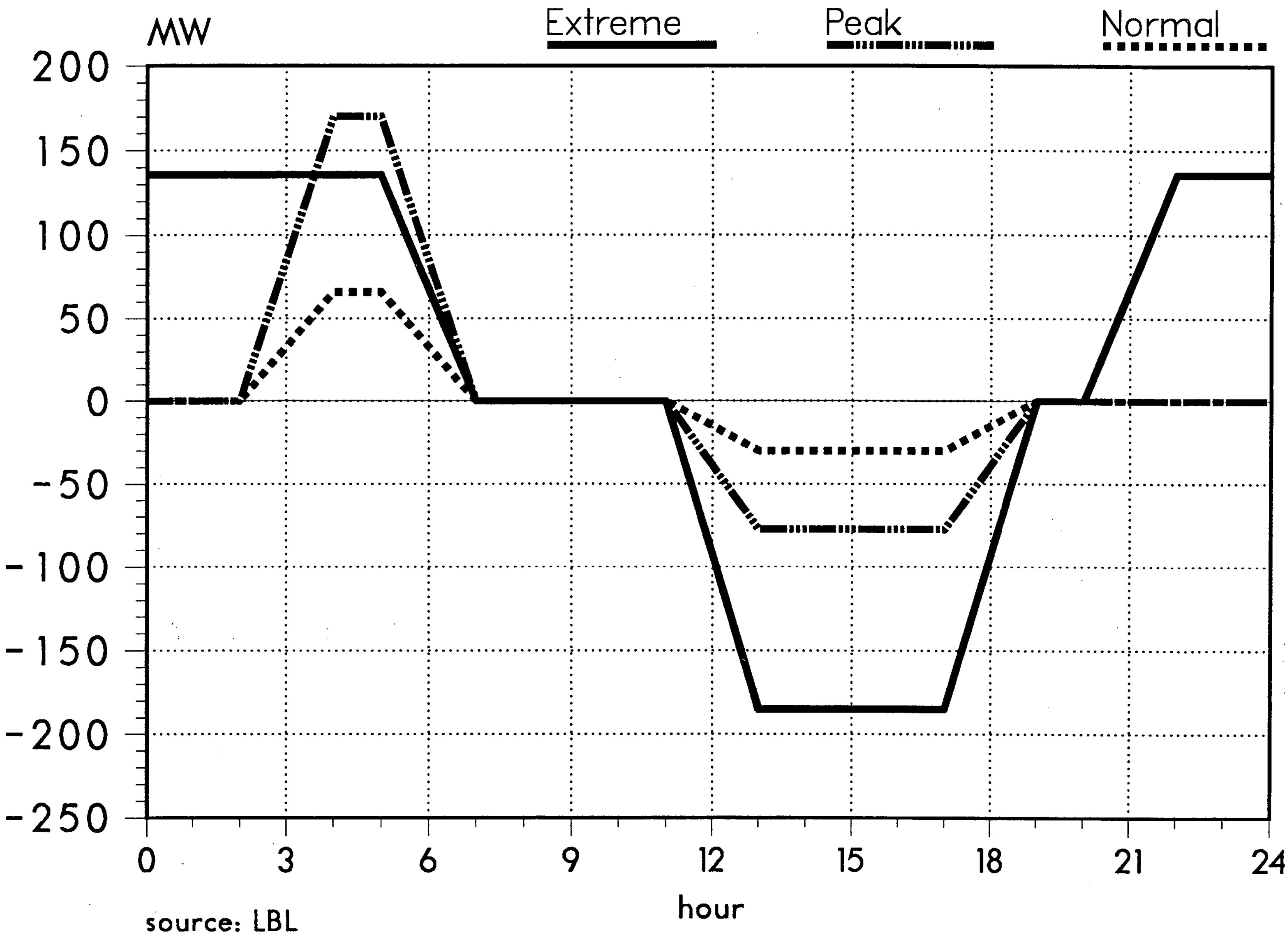
Sensitivities:
A: Primary Case
B: Incremental cost of TES increased to $1,015/Avoided-kW
C: Utility avoided cost increased to $725/kW; D.C. of TES to $1,420/Avoided-kW

d) TES Results Summary

The results presented above show that adding enough TES to reduce demand on the the PG&E system by 200 MW has significant value to society. The value to the utility under a future of static rates is negative, however, because current demand and energy charges are significantly higher than costs. Given our base set of assumptions, the present-value loss to the utility is $108.4 M if it offers incentives. For the utility to break even with direct incentives, marginal rates to TES adopters would have to be reduced 46%.[34] If the number of TES installations is increased 6 times to 1,200 MW of avoided peak demand, fuel savings do not scale proportionally--they increase only 4 to 5 times. The existence of diminishing returns is also shown in the changes in marginal costs. While the 200 MW program simulated in run #120 has a very small impact on marginal costs, the 1,200 MW program increases marginal costs considerably. This is a result of the large program decreasing on-peak costs a small amount but increasing off-peak costs a large amount.

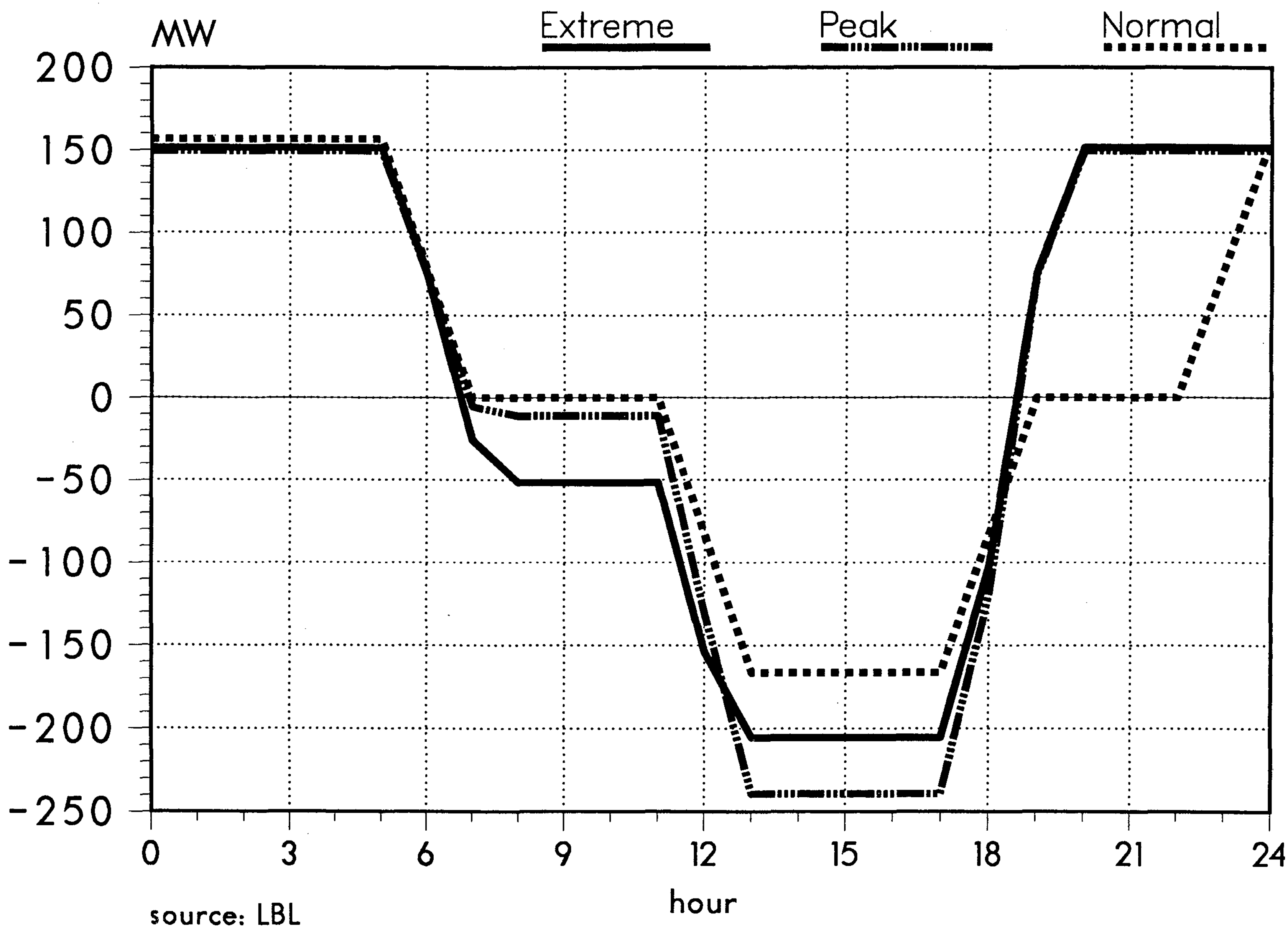
[34] Alternatively, revenue would have to collected from other customers.

Figure VI.1
Incremental Load Impact of TES
(WINTER 1996 - 2003)



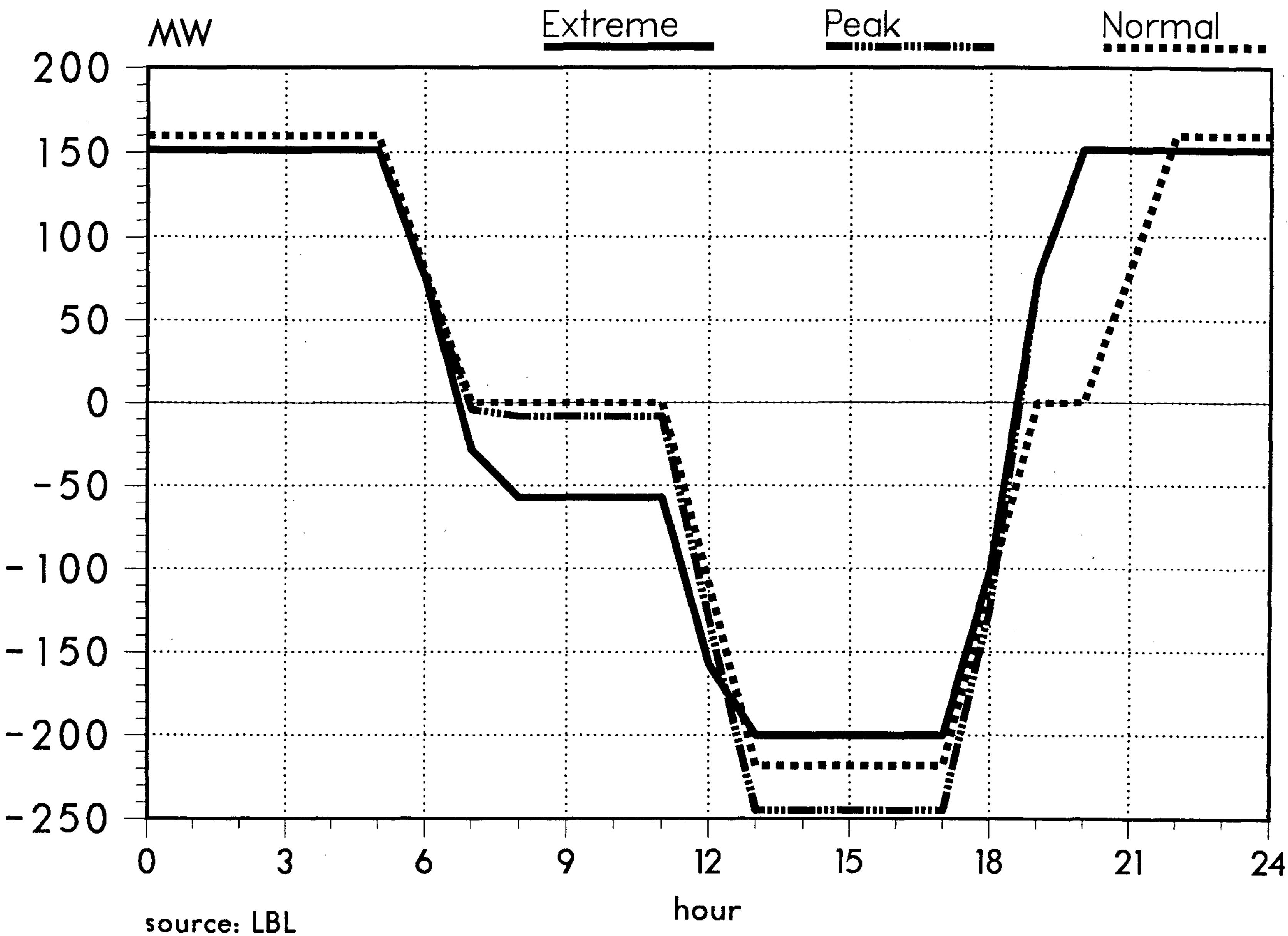
source: LBL

Figure VI.2
Incremental Load Impact of TES
(SPRING 1996 - 2003)



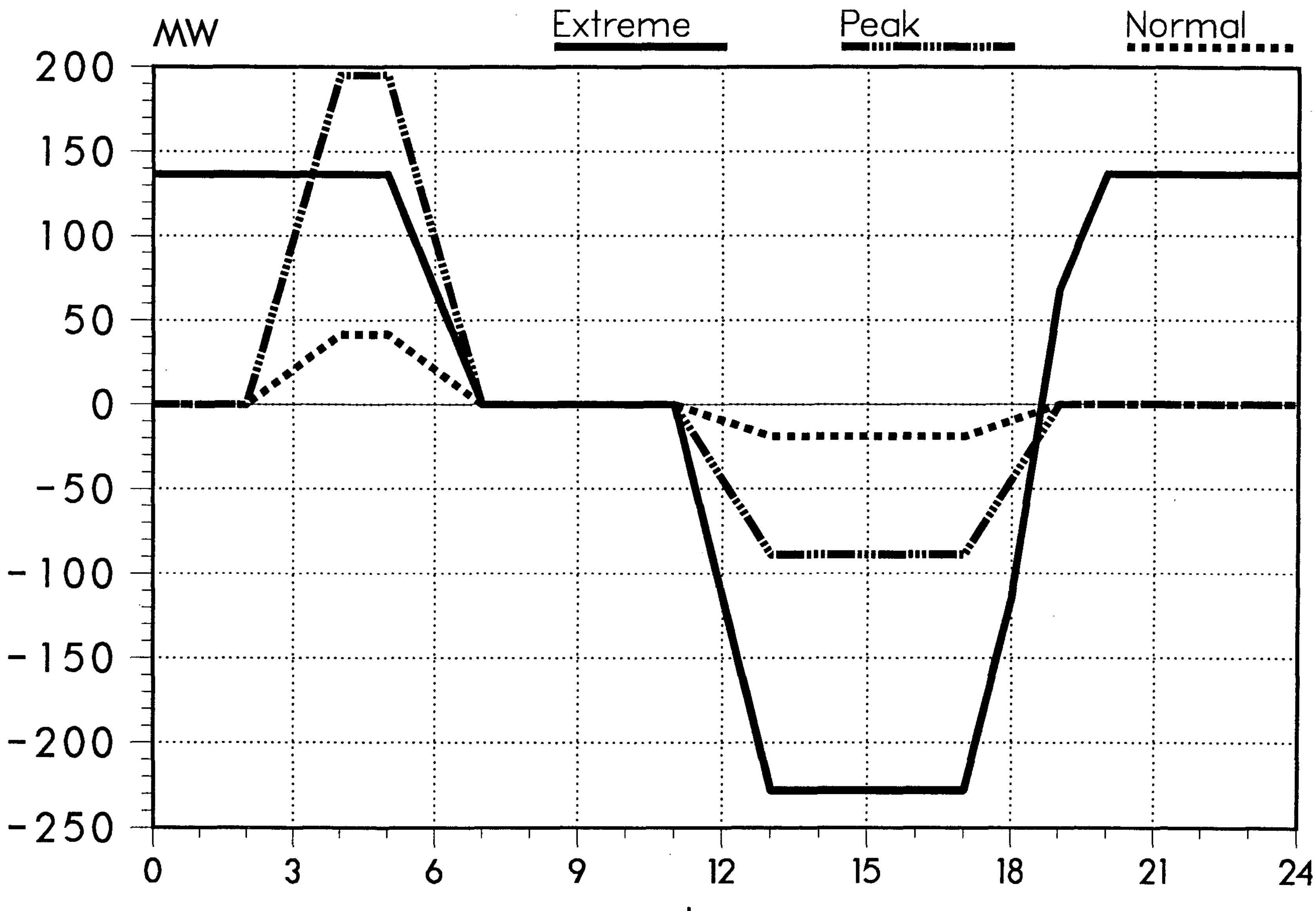
source: LBL

Figure VI.3
Incremental Load Impact of TES
(SUMMER 1996 - 2003)



source: LBL

Figure VI.4
Incremental Load Impact of TES
(FALL 1996 - 2003)



source: LBL

Figure VI.5
PGandE System Load Under Base and Two Policy Cases
(TES - Summer Extreme Days 1996)

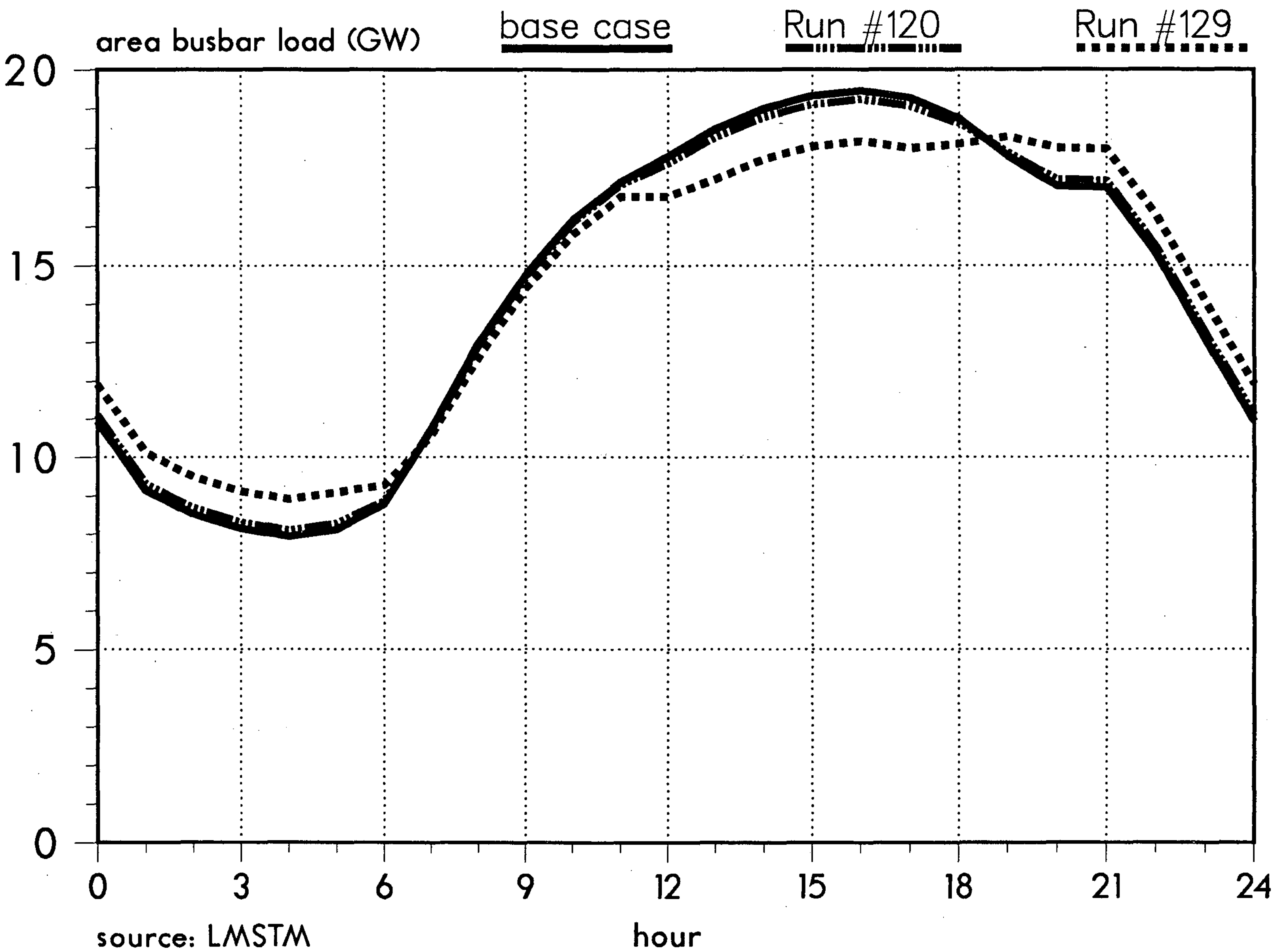
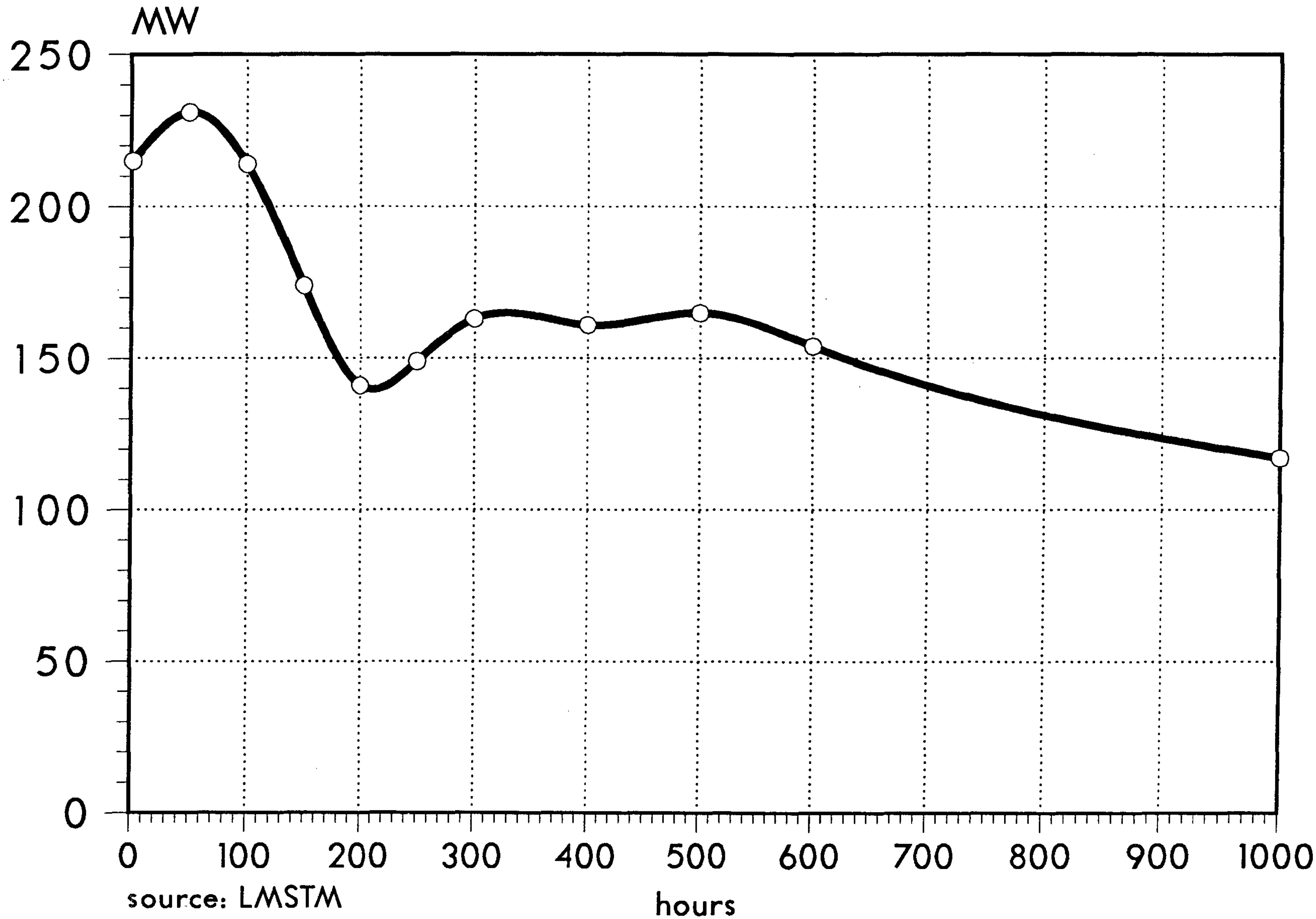


Figure VI.6
Sensitivity of Peak Reduction to Hours of Averaging
Thermal Energy Storage - 2003



source: LMSTM

VII. RESIDENTIAL AIR CONDITIONING

The second demand-side program considered is a more familiar one than TES, both to LBL and PG&E. It is a program of improved efficiency standards for residential air conditioning and heat pumps. This analysis draws on past LBL work on PG&E, (Eto, *et al*, 1984). In the current study that work is updated and linked to our LMSTM modeling of PG&E. This brings LBL's appliance efficiency research into an explicit LCP framework.

1. The LBL-REM Model

The basis of both efforts to model PG&E's residential sector is use of the Lawrence Berkeley Laboratory Residential Energy Model (LBL-REM), and the LBL Hourly Demand Model, which is a load simulator that disperses LBL-REM energy use estimates across all the hours of the year. For simplicity "LBL-REM" will be used to refer to both models run in tandem. LBLREM is purely a residential energy model, so it cannot be used to simulate system loads. It has to be used as the generator of adjustments to system loads. This raises some important issues of coincidence between demand in the residential and other sectors, which are briefly discussed in Section III. LBL-REM conducts a sophisticated bottom-up simulation of residential energy use of several forms, not only electricity. LBL-REM incorporates changing appliance and housing efficiencies, income forecasts, population changes, and models of customer appliance purchase decisions as well as usage decisions (McMahon 1987).

The function of LBL-REM in this study is to forecast the load change resulting from the policy residential air conditioning efficiency standard. The output of LBL-REM is a 8760-hour matrix of loads for any test year of the study period. The load shapes output for the base and policy cases can be differenced to yield a matrix of load decrements to the system. This mass of load data can then be reduced to the form of LMSTM daytype load shapes through use of a variation of the program, DTSPLT, which was written in stage 1 to reduce raw PG&E load data to LMSTM inputs. The 16 load shapes derived in this manner appear as Appendix J.

In this case, therefore, LBL-REM was the source of load change information, and LMSTM is employed only to analyze the implications of the change. That is, the demand side of LMSTM was short-circuited by use of LBL-REM. This is the usual approach to LCP either because no holistic model is available, or because familiarity with or confidence in a particular model is greater than the corresponding part of the holistic model being used. However, the implications of this approach are non-trivial. One of the major attractions of the holistic models is their ability to solve the whole least-cost problem simultaneously (Pignone, *et al*, 1986). Substituting exogenous calculations or models for endogenous LMSTM processes jeopardizes the simultaneity of the solution because a cleavage quickly develops between assumptions used in the exogenous and endogenous calculations. Patching up this rift requires an iterative process that, hopefully, converges on a unique solution. Carrying out this iteration is a clumsy and time-consuming process, and doing it well is beyond the resources available for this study. However, one significant step was made in this direction. The trajectory of retail electricity prices was fed back into LBL-REM so that any change in rates that emerged as a result of the standard was actually seen by residential customers. This feedback loop was achieved by means of a small program that converts the LMSTM outputs in the SUMMARY.T file into the real relative price trajectory that LBL-REM requires. The effect of this process was negligible because the price effect was too small. In most years, the policy case never resulted in prices more than 1-2 % below the base case, and for most years the prices were identical. Further, LBL-REM generally exhibits small price responses. Note that this is only a very partial fix-up because the price change was seen only by residential customers and the effect of the change on other sectors would still not be accounted for. A possible fix up for this problem, not used in this study, would be to use the price elasticities in LMSTM to simulate a reasonable level of price response. This is an example of how using a model outside the holistic framework comes at a cost that may or may not eliminate the advantages of using a model in which one has more confidence than in the corresponding elements of the holistic model.

2. Baseline Territories

The key of LBL's approach to modeling PG&E's residential sector in the 1984 study was to disaggregate the sector into four baseline territories and a fifth residual region. In this study the baseline territory approach has again been used but without the residual territory. That is, only the territories R, S, T, and X are modeled and no attempt is made to scale up the results to encompass the whole service area. The regions are shown in Figure VII.1. Three reasons motivated the rate region by rate region approach in LBL's original study. First, these territories are climatically defined and serve as a useful way of capturing the climatic diversity of PG&E's large service territory. Second, the revenue impacts were best modeled at this level because the baseline allowances vary across baseline territory. This effect is no longer important, since the changeover to baseline has reduced the steepness of rates, and all air-conditioning customers can be reasonably assumed to lie in the upper tier. That is the assumption made here. That is, all sales lost in the residential sector are priced at the upper tier, 10.23 ¢/kWh. The third advantage of this approach is that it permits a more accurate representation of population growth patterns, which are uneven in the PG&E service area. Particularly, population growth is faster in the high air conditioning areas of the valley than it is along the temperate coast, where most of the population currently resides. A recent complication has been some redistricting done by the PUC in recent rate hearings. Figure VII.1 shows the regions as they are defined for this study. Figure VII.2 shows the actual boundaries as they stood after the Dec. 1986 general rate case. While the differences are not great, there have been some significant changes. In general, in this study the pre-1986 boundaries have been used. That is, region P has been absorbed by S, and Q by T, and other changes have been ignored. The total of the regions R,S,T and X, by this definition, accounts for about 93% of PG&E's customers, and a similar fraction of sales.

The mythical region D, which the reader will see in some tables, refers to the SMUD service territory, which was almost included in this study. This is again a practical withdrawal from a more pristine least-cost world. Since SMUD resources are dispatched by PG&E, and in the characterization of PG&E embedded in the LMSTM input files used here, these resources do appear, logically SMUD should also be included on the demand side. Further, the role of the SMUD territory on the demand side is significant. SMUD has about a third of a million customers, as many as PG&E's R rate region, their numbers are growing, and central air conditioning saturation is well over 50%, higher than in any of the PG&E rate regions. Further, excluding SMUD creates an anomaly because a statewide efficiency standard would clearly effect demand in the SMUD territory and would have an effect on the PG&E system, as we have modeled it. However, the financial complications that introducing SMUD to the analysis would create were too burdensome to attempt. First, the prices faced by SMUD customers are significantly lower than PG&E customers, currently about 7 ¢/kWh, so this region would have to be treated independently in LBL-REM. Further, the price trajectory faced by PG&E customers might have little relevance to the expected future of SMUD costs. Second, a cost saving on the PG&E system as a result of conservation by SMUD customers would be difficult to allocate. LMSTM by its nature would reduce revenue requirements, and the reduction would have to be divided between SMUD and PG&E customers in some exogenous calculation.

The actual forecast numbers of customers appear in Appendix F. The forecast is a simple straight line forecast with assumed growth rates that appear at the foot of the tables. The growth rates reflect the belief that population will be growing faster in the Valley areas. The assumed growth rates are high compared to those that appear for the 1985-2000 period in PG&E forecasts, which were not available in time to be reflected in this study (PG&E, 1987).

The growth rate for San Joaquin Valley, which might be taken as a proxy for D, R and S, shows a growth rate of 2.81% versus the assumption used here of 5%; and the growth rate for Golden Gate, a possible proxy for T, grows at a rate of 0.72% versus 1%; and, finally, East Bay, a possible proxy for X, grows at 1.4% versus 2%. Of these discrepancies, the first is the most worrisome. The divergence is greatest and it occurs in the area of highest air conditioning saturation. This implies that LBL-REM is being given too many new homes in which to install efficient new air conditioners, and, consequently, a bias towards overestimation of the effect of the policy has been introduced. However, it should be noted that there is no clear correspondence between the regions used at PG&E for demographic forecasting and the rate regions on which this analysis is based. The San Joaquin Valley region referred to above, for example, does not contain the fast-growing Sacramento area while it does contain the Sierra foothills not included in rate regions D, R and S. Resolving such discrepancies is no simple task and is beyond the scope of an exploratory study such as this.

3. The Air Conditioner Standard

In this analysis the effects of the imposition of an air conditioning efficiency standard are analyzed. Studying the consequences of the exogenous imposition of a standard is a different kind of policy case than an incentive program, like the TES case considered earlier. In this case, the policy is totally exogenous and only the consequences are considered. This case is more tractable than an adoption incentive program because it simplifies the burden of having to estimate the penetration rate of the policy, often the most uncertain parameter. Therefore, in the RAC policy case, the efficient appliance standard is enforced by fiat, and everything else can be left to settle as it may. Such a policy alternative is not a likely candidate for a company least-cost plan, but is obviously a candidate for a statewide plan, and it is an interestesting boundary case that illuminates other problems that might arise in LCP, even in the absence of the penetration issue. Further, this type of analysis permits analysis at a level of detail that would be unsupportable if results also rested on a shaky assumption of customer acceptance. The actual standards used are listed in Table VII.1. The standards tighten expected California standards twice, in 1989 and 1993. The high efficiencies demanded are well within ranges achievable with current manufacturing methods and models meeting the 1993 standards are available today, although at a considerable cost premium (Geller, *et al*, 1986, Krause, *et al*, 1987, O'Neal, *et al*, 1986). After 2003 the world stands still until the end of any planning horizon chosen. The stock of equipment in place, energy usage levels, etc., stay fixed until the end of time.

4. Results

a) Sales of Efficient Appliances

Figures VII.3, VII.4, and VII.5 show the sales forecast for the three appliances output by LBL-REM. The Figures show demonstratively the importance of the two valley regions, R and S, in

Table VII.1
Specification of Minimum Residential Air Conditioning Efficiencies for the Base and Policy Cases

Case and Appliance	Standard in Period: 1980-1988	1989-1992	1993-
Base Case			
Central Air Conditioners and A.C. Heat Pumps (SEER)	8.0	8.9	9.9
Room Air Conditioners (EER)	8.7	8.7	8.7
Policy Case			
Central Air Conditioners and A.C. Heat Pumps (SEER)	8.0	10.0	13.0
Room Air Conditioners (EER)	8.7	9.0	9.5

the air conditioning market. With only 15 and 19% of the customers, they provide 30 and 38% of the CAC sales in 2003. As one would expect, T is a very minor player, and X, while it has lower temperatures than the valley, has so many customers, 42% of the four territory total, makes a major contribution. A second interesting feature of the plots is the visible price response, which, while not spectacular, gives reason for some confidence in the workings of LBL-REM. The effect is most noticeable in the CAC sales for X. The falling real price of the early 1990's gives rise to brisk growth in appliance sales, but towards the end of the study period, the rapidly rising rates cause a flattening of appliance sales. Note that growth rate of customers in each region is fixed by assumption, so that any change in the rate of sales derives from the appliance buying and usage behavior.

b) Changing Appliance Efficiency

Figures VII.6, VII.7, and VII.8 show how the purchase of efficient new equipment that complies with the standard is affecting the average efficiencies of the existing stocks of the three appliances. Again the effect of the rapid growth in appliance sales in the mid-1990's is clearly visible.

c) Sales and Load Impacts of Standards

Figure VII.9 shows the sales impact of the standards. Once again the effect is strongest in the early 1990's, and falls off towards the end of the test period. After 2003, the effect becomes flat by assumption, since for the purposes of this analysis the world freezes in 2003.

In the case of RAC, the reasonable expectation is that the load reduction will diminish further from the peak because fewer of the efficient appliances are turned on, the further one is from the peak, making air conditioning efficiency improvements an effective form of peak reduction. Figure VII.10 shows the load shave that was generated for the summer extreme day of 2003. This shape is derived by averaging across the four days of highest residential sales, according to LBL-REM. This is the daytype and year of maximum effect, that is, 415 MW of peak saving. As is clearly shown, the effect of the standard is a very even load decrement across the peak hours, and the policy is a very effective load management strategy. Further, as one would expect, no load building results from the policy at any hour. However, the peak hours, for example 12:00-18:00 on the summer extreme day only total 24 hours of the LMSTM system year, although they are ones of particular interest. As described in section III, how many hours should be considered for the purposes of system planning is far from an undisputed number. For this reason, the LODAV program was written to analyze LMSTM outputs.

Figures VII.11, VII.12, and VII.13 portray the results of averaging the effect of the policy over increasing numbers of hours. In Figure VII.11, the absolute maximum peak saving is seen to be 415 MW, while the average reduction over the first 100 hours is 300, etc. Our benchmark for this study, 150 hours, is also shown. The top 150 hours all occur at the hottest times of the year and appear to capture an overwhelming fraction of the annual LOLP. The RAC program delivers about 275 MW of capacity savings with 150 hours of averaging. Allowing a 20 % reserve margin credit, this capacity saving translates to about 330 MW of avoided capacity. This example and shape of Figure VII.11 emphatically shows the sensitivity of results to the hours of averaging chosen. Quite credible arguments can be made for using any number of hours in the 0-500 range, and the choice can totally drive results.[1] The shape of the plot in VII.11 suggests exponential decay, and VII.12 shows the same data plotted on a log axis. Indeed, the curve in VII.12 is very close to straight, and Figure VII.13 shows that this linearity holds well beyond the top 500 hours for a residential air conditioning program. For a residential air conditioning load reduction program log linearity is a good rule of thumb for estimating the effect of averaging over various numbers of hours; however, if one point estimate of peak saving were available it would most likely be the saving at absolute peak, or hour 1 in Figure VII.12, and this would have to be interpreted carefully because the load shave is virtually flat over the top 10 hours. This characteristic logarithmic nature of the load shave can easily produce a factor of greater than 2 range in estimates of the capacity reduction and plays havoc with any notions of estimating a valid capacity value. Figures VII.14 through VII.16 show the load data in a different form. The system loads are ranked from highest to lowest, so point 500 on the x axis is the hour with the 500th highest load, and the y axis shows the percentage load reduction that occurred at that hour. As is clear, points appear all over the plot, which shows that even though the averaged MW fall in load at the hours further from the peak is declining evenly in this case, the proportional load impact is not. In fact, even in the first few hundred hours, points cover the full range of effect, from 0 to 2 %. However, looking at the plot of summer hours only, Figure VII.15, an even drop over the first 170 hours is observed. The confusion in the annual plot, Figure VII.14, is caused by the presence of high load spring days high in the ranking of loads. Figure VII.16 shows the spring hours only. It is not surprising that many high load days fall within the definition of spring used here, since very hot days occur in May and June. What is surprising is that the load reduction generated by LBL-REM for the spring hot days is so different to that produced for the summer hot days. What, if anything, can be learned from this? First, VII.14 demonstrates that making the assumption that the percent load reduction across any number of the top hours is a constant fraction would be quite false. Drawing any realistic conclusions about the effect of the program across any number of the top load hours requires careful analysis of the load data. Applying the LODAV program to this data has shown some major uncertainties exist in estimating the capacity value of avoided peak requirements. Second, the disparity in results between the spring and summer results from LBL-REM, indicates that a poor job has been done either of dividing the matrix of load decrements into LMSTM daytypes or of calibrating LBL-REM to the distribution of spring appliance loads. That is, either some of the high residential load days are

[1] The first cold weather peaks appear in an ordinal ranking of hourly loads at about the 500th hour.

not high system load days, that is, hot days, or they are hot days but LBL-REM is not producing as significant a load reduction as it does on hot summer days.

d) Generation Consequences

Table VII.2
Comparison of Supply Submodel Outputs
(Year = 1996)

	Base Case #115	RAC Only Case #117	#117 Minus #115	RAC & Supply Deferral Case #127	#127 Minus #115
Resource	Yearly Production (GWh)				
Nuclear	16,453	16,447	-6	16,459	6
Oil & Gas	10,816	10,739	-77	10,703	-113
Geysers	10,462	10,462	0	10,462	0
Other Geo	2,361	2,359	-2	2,360	-1
EOR QF's	498	497	-1	498	0
Other QFs	20,652	20,652	0	20,652	0
Self Genr	3,613	3,613	0	3,613	0
Gen Baseld	280	280	0	281	1
NW Thermal	3,082	3,051	-31	3,071	-11
Pumped Stg	1,261	1,243	-18	1,255	-6
Hydro	29,648	29,648	0	29,648	0
Total	99,126	98,991	-135	99,002	-124
LMSTM Period	Avg. of Hourly Marginal Costs (¢/kWh)				
Winter	2.91	2.91	0.00	2.91	0.00
Summer	4.38	4.38	0.00	4.38	0.00
Fall	4.68	4.68	0.00	4.68	0.00
Spring	1.89	1.79	-0.10	1.79	-0.10
Annual Avg	3.56	3.54	-0.02	3.54	-0.02
	Incremental Energy Rate (Btu/kWh)				
Annual Avg	6,431	6,401	-30	6,401	-30

Tables VII.2 and VII.3 show the effect on generation by fuel type for the base case, run 115, a policy case with no supply-side deferral, run 117, and a policy case with maximum deferrals, run 127. The results show the expected pattern. Oil and gas use falls significantly, NW thermal purchases fall, and nuclear increases. The result for pumped storage is inconsistent, falling in 1996 but increasing insignificantly in 2003. The change in marginal costs is insignificant in 1996, but shows the expected pattern in 2003. The greatest fall is in summer, where the average falls a dramatic 0.59 cents. Spring is, however, beaten into third place by fall, which reconfirms that all is not well with the characterization of spring used. Nonetheless, the results all show the correct sign.

Table VII.3 Comparison of Supply Submodel Outputs (Year = 2003)					
	Base Case #115	RAC Only Case #117	#117 Minus #115	RAC & Supply Deferral Case #127	#127 Minus #115
Resource	Yearly Production (GWh)				
Nuclear	16,706	16,705	-1	16,720	14
Oil & Gas	16,896	16,684	-212	16,653	-243
Geysers	10,462	10,462	0	10,462	0
Other Geo	2,366	2,366	0	2,367	1
EOR QFs	635	633	-2	634	-1
Other QFs	21,174	21,174	0	21,174	0
Self Genr	6,025	6,025	0	6,025	0
Gen Baseld	303	303	0	303	0
NW Thermal	4,683	4,621	-62	4,634	-49
Pumped Stg	1,253	1,251	-2	1,254	1
Hydro	29,711	29,711	0	29,711	0
Total	110,214	109,935	-279	109,937	-277
LMSTM Period	Avg. of Hourly Marginal Costs (¢/kWh)				
Winter	7.83	7.83	0.00	7.83	0.00
Summer	9.11	9.34	0.23	8.52	-0.59
Fall	9.47	9.45	-0.02	9.36	-0.11
Spring	4.97	4.93	-0.04	4.95	-0.02
Annual Avg	8.09	8.13	0.05	7.91	-0.18
	Incremental Energy Rate (Btu/kWh)				
Annual Avg	7,703	7,747	44	7,532	-171

e) Financial Consequences

Table VII.4 shows the summary EVALER output for the RAC case. From the societal perspective, this policy is a clear loser. Only with a 40-year time horizon under method 2 does the present benefit turn positive. In the RAC case the most convincing time horizon is to 2014. This is the year in which new appliances bought in 2003, the last year of the program, reach the end of the mean lifetime assumed in LBL-REM. That is, the customers who have bought the more efficient appliances have received the full benefit of bill savings and all efficient appliances can be assumed to have been replaced with ones of the same efficiency that would have been in place in the absence of the standard. As discused elsewhere, this does not take care of the end of period problem on the supply side, because the adjustments made in the supply plan as a consequence of the load effect of the standard will continue to affect operations for the lifetime of the last plant deferred. However, for simplicity, the results presented here overlook these issues and show estimates for the three time horizons with no attempt to adjust the output of EVALER. As expected, method 2 gives more favorable results than method one.

Table VII.4
Societal Net-Benefit of RAC

Run #127 vs. #115
Present Value of Dollar Streams Starting in 1987 (in 1987 dollars)
10% Nominal Discount Rate Used

	To 2007	To 2014	To 2027
1. Variable Operating Cost Savings	118.5	185.5	263.1
2. Capital Cost Savings: Method 1	67.5	67.5	67.5
3. Capital Cost Savings: Method 2	112.3	151.5	196.7
4. Ratio of Two Cap. Cost Methods (3/2)	1.7	2.2	2.9
5. Incremental Cost to RAC Adopters	338.2	338.2	338.2
6. Net Benefit: w/ Method 1 (1+2-5)	-152.5	-85.2	-7.6
7. Net Benefit: w/ Method 2 (1+3-5)	-107.7	-1.2	121.5

Note: Method 2 Capacity value in right-most column is approximate.

Table VII.5
Derivation of Customer Costs

year	room sales (E3)	room cost ($)	room total (M$)	CAC sales (E3)	CAC cost ($)	CAC total (M$)	HP sales (E3)	HP cost ($)	HP total (M$)	TOTAL (M$)
1989	46.5	61.74	2.9	76.8	117.69	9.0	14.6	136.99	2.0	13.9
1990	48.0	64.83	3.1	79.1	119.52	9.5	16.0	141.81	2.3	14.8
1991	50.4	68.07	3.4	84.3	125.50	10.6	17.1	148.90	2.6	16.6
1992	53.4	71.47	3.8	90.8	131.78	12.0	17.6	156.34	2.8	18.5
1993	57.1	98.50	5.6	95.9	361.16	34.6	17.7	354.12	6.3	46.5
1994	60.4	103.42	6.2	102.4	379.21	38.8	18.3	371.83	6.8	51.9
1995	63.9	108.59	6.9	108.4	398.17	43.2	19.1	390.42	7.5	57.6
1996	67.8	116.74	7.9	115.5	418.78	48.3	19.5	409.94	8.0	64.2
1997	71.8	122.57	8.8	123.3	438.99	54.1	19.6	430.44	8.4	71.4
1998	75.3	128.70	9.7	129.4	460.94	59.6	20.2	451.96	9.2	78.5
1999	78.1	135.14	10.6	133.9	483.98	64.8	21.3	474.55	10.13	85.5
2000	80.4	141.89	11.4	137.6	508.18	69.9	22.6	498.28	11.26	92.6
2001	82.3	145.52	12.0	140.0	533.59	74.7	23.9	523.20	12.52	99.2
2002	84.5	152.80	12.9	142.9	560.27	80.1	25.3	549.36	13.92	106.9
2003	86.8	156.62	13.6	146.0	588.28	85.9	26.7	573.00	15.29	114.8

source: LBL-REM

As expected, the variable operating cost saving is substantial because so many of the kWh saved are from oil and gas generation. As in the TES case, the ratio of the capital savings under method 2 are considerably bigger than under method 1, and this ration increases over time. The reason for the bottom line coming out so dramatically negative is the high customer costs of the program, whose present value is over 338 M$. These are the out-of-pocket dollars spent by appliance purchasers to buy appliances more efficient than the ones they would have chosen otherwise. The derivation of these costs is outlined in Table VII.5. These figures are an output of LBL-REM, which uses a matrix of costs for various levels of efficiency to ensure that customers see the right costs when they make appliance purchase decisions. For each of the three appliances, the sales are multiplied by LBL-REM's estimate of the difference between the cost of an appliance meeting the standard and the one that would have been bought in the absence of the standard. The right column is the sum of all the costs, and the present value of this stream is the origin of the hefty 338 M$ that drives the cost benefit result.

Since this number is so critical, it is worthy of more close attention. It represents a rather crude estimate of the actual customer costs of the standard because the sales of appliances differ in the base and policy cases. Particularly, the higher cost of appliances discourages some customers from buying all together, and they bear the cost of forgoing air conditioning which evades the estimation method used here. So the estimate of customer costs referred to here is really only the out-of-pocket costs of consumers who bought air conditioners during the policy period. In keeping with the goal of keeping assumptions as consistent as possible across the various models used, these LBL-REM cost outputs are fed directly into EVALER.

Cross checking shows that LBL-REM's costing algorithm is requiring customers to pay $117 per SEER of efficiency improvement for central air conditioning, $116 per SEER for heat pumps, and $68 per EER for room air. Actually, this number is artificially low because recent modifications to LBL-REM would raise these costs to about $219 per SEER. The range of efficiencies concerned, that is, near to 13 for CAC and HP and 10 for room, is not close enough to the limits of existing technology for costs to rise dramatically. A brief review of the literature suggests this level of efficiency is easily attainable with first order design improvements, that is, upscaling the heat exchanger size, etc. More expensive improvements, such as two-speed compressors, which significantly raise costs, are only needed to achieve SEER's beyond the 14 to 15 range. LBL-REM's $117 cost per SEER is low on the scale of opinions on such costs (Geller, *et al*, 1986, Booz, Allen, and Hamilton, 1985), but the $219 seems to be in the mid-range. Current market prices infer costs of the order of 1987$300/SEER, although a fall is likely as efficient models are produced in higher volumes, and for the period of rapid equipment purchasing, in the mid-1990's, costs of 1987$150-250/SEER seem reasonable.

These figures make the LBL-REM customer cost number look optimistic, which leads to the first of three sensitivity cases that appear in Table VII.6. Sensitivity B raises the customer cost of RAC in the proportion of 200/117 which is an approximation to assuming a $200/SEER cost versus $117. This adjustment raises the net societal loss to 323 M$, which shows that this policy case is a clear loser and is unlikely to pay under any reasonable assumptions.

The other two sensitivities concern changes on the utility side. The first, sensitivity C, raises the value of capacity to $725/kW, which is the value that was found by iteration to drive the societal benefit to the break even point. Ironically, this is exactly the value that was used in the TES section as the ACEE value of capacity inflated to 1987$. This is purely a coincidence but does emphasize that capital costs in this range are reputable and this sensitivity shows that under the other base assumptions and this cost the RAC program could break even.

The final sensitivity, D, is motivated by the nature of the RAC load shave. As noted above, air conditioning control is effective at displacing high cost oil and gas generation. Further, the trajectory of oil prices is one of the largest uncertainties in any energy forecast, and, since this study originated in a period of low and unstable oil markets, this is an area of special interest. In sensitivity D the 1996 oil price is doubled from approximately 1987$20/barrel to $40 and all

Table VII.6
Sensitivities to Societal Net-Benefit of RAC

Run #120 vs. #115 and #132 vs. #124
Present Value of Dollar Streams 1987 - 2014 (in 1987 dollars)
10.0% Nominal Discount Rate Used
Method 1 for valuing capacity benefit

	Sensitivity			
	A	B	C	D
1. Variable Operating Cost Savings	185.5	185.5	185.5	369.9
2. Capital Cost Savings: Method 1	67.5	67.5	152.9	67.5
3. Direct Cost to RAC Adopters	338.2	575.8	338.2	338.1
4. Net Benefit: w/ Method 1 (1+2-3)	-85.2	-322.8	0.2	99.2

Sensitivities:
A: Primary Case
B: Direct cost of RAC increased to approx. $200/SEER equivalent
C: Utility avoided cost increased to $725/kW
D: 1996 oil price doubled

other years are interpolated accordingly by the use of an escalation rate that produces the desired result. This sensitivity is very illuminating. As one would hope, LMSTM produced variable operating cost savings of very close to double the primary case, which is encouraging. And, indeed this turns the net societal benefit strongly positive. Since this effect is linear, it can be clearly seen that the break even point would be in the range of 1987$30/barrel for oil in 1996. Certainly, this is not possibility that can be *a priori* discounted.

In conclusion, the societal perspective on the program is negative under method 1 and it is difficult to envisage a circumstance in which it could be endorsed from this point of view. Method two makes the program close to break even at the 2014 horizon, but as mentioned in section III, this method may be too generous with distant horizons. Of the sensitivities, B is the most damming. It appears that the customer costs that are generated by LBL-REM are too low by the standards of current thinking, and, since they are the dominant negative already, increasing them dramatically deteriorates the result. The other two sensitivities on utility costs show that in the absence of the customer cost problem, reasonable assumptions such at $725/kW generation and 1987$30/barrel oil can reverse the bottom line.

Table VII.7
Utility Net-Benefit of RAC

Run #120 vs. #115 and #132 vs. #124
Present Value of Dollar Streams 1987 - 2014 (in 1987 dollars)
10.4% Nominal Discount Rate Used
Method 1 for valuing capacity benefit

	Sensitivity A	Sensitivity C	Sensitivity D
1. Capacity Cost Savings: Method 1	65.3	147.9	65.3
2. Variable Operating Cost Savings	173.8	173.8	346.5
3. Revenue Loss from Cust. Bill Savings	236.0	236.0	236.0
4. Net Revenue Loss (3-2)	62.2	62.2	-110.5
5. Benefit (1-4)	3.1	85.7	175.8

Sensitivities:
A: Primary Case
C: Avoided capacity valued at $725/kW
D: Oil price doubled

Table VII.7 shows the primary case and sensitivities C and D from the utility perspective. The utility benefits under each of the three cases. Although customer bill savings are large they are smaller than the drop in utility costs in each case.

Figure VII.1

Approximation of PG&E Rate Regions

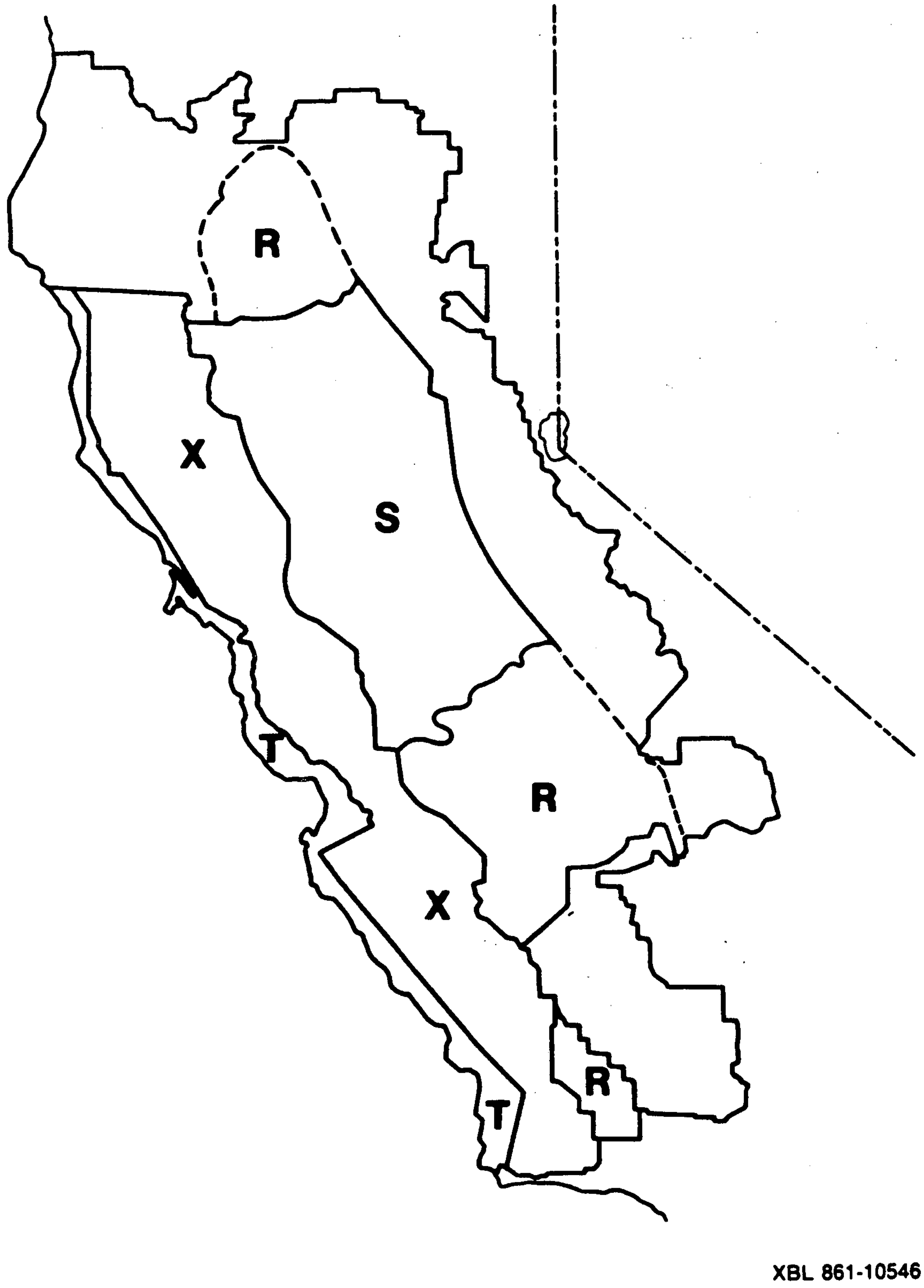


Figure VII.2

Actual PG&E Rate Regions

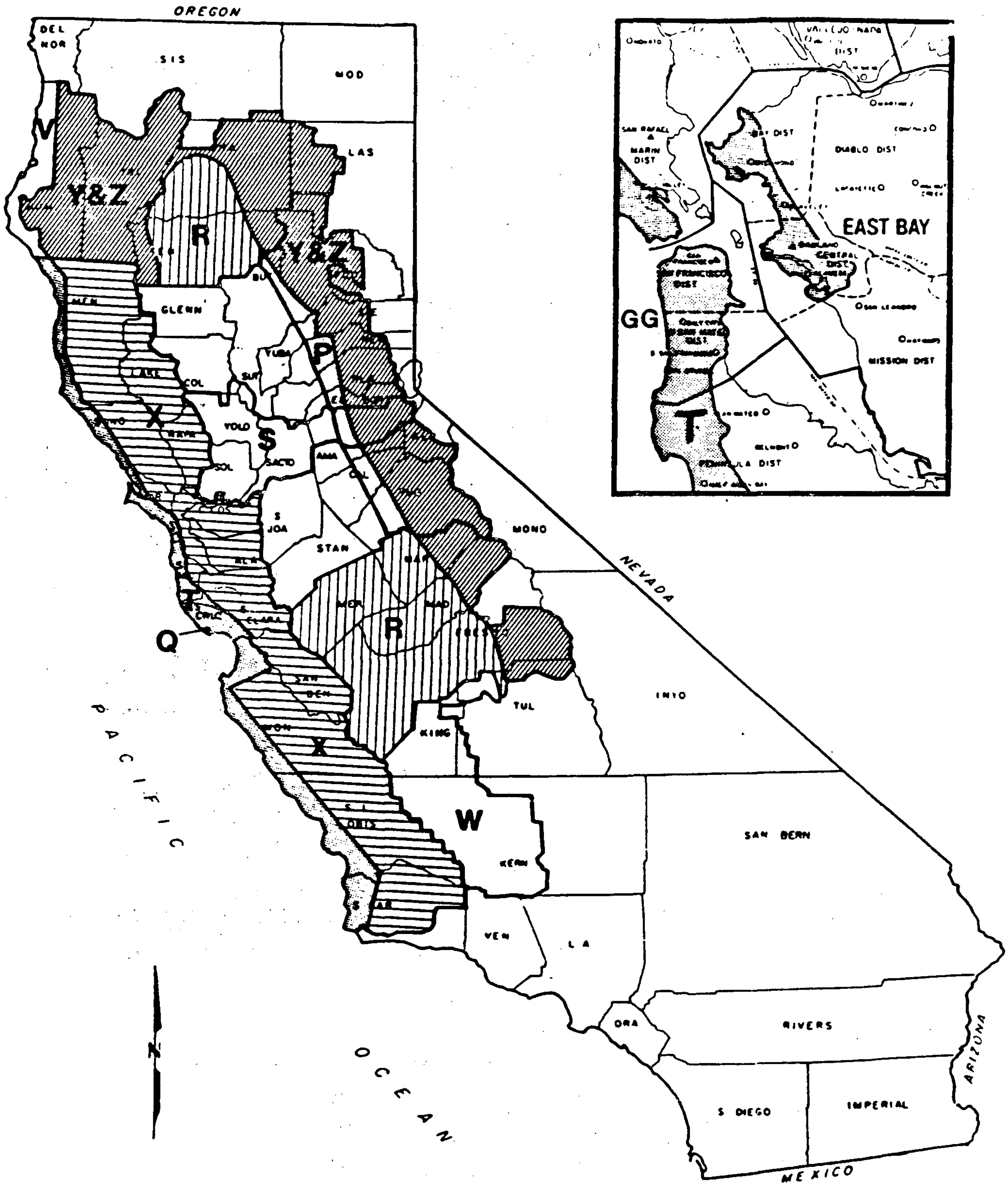
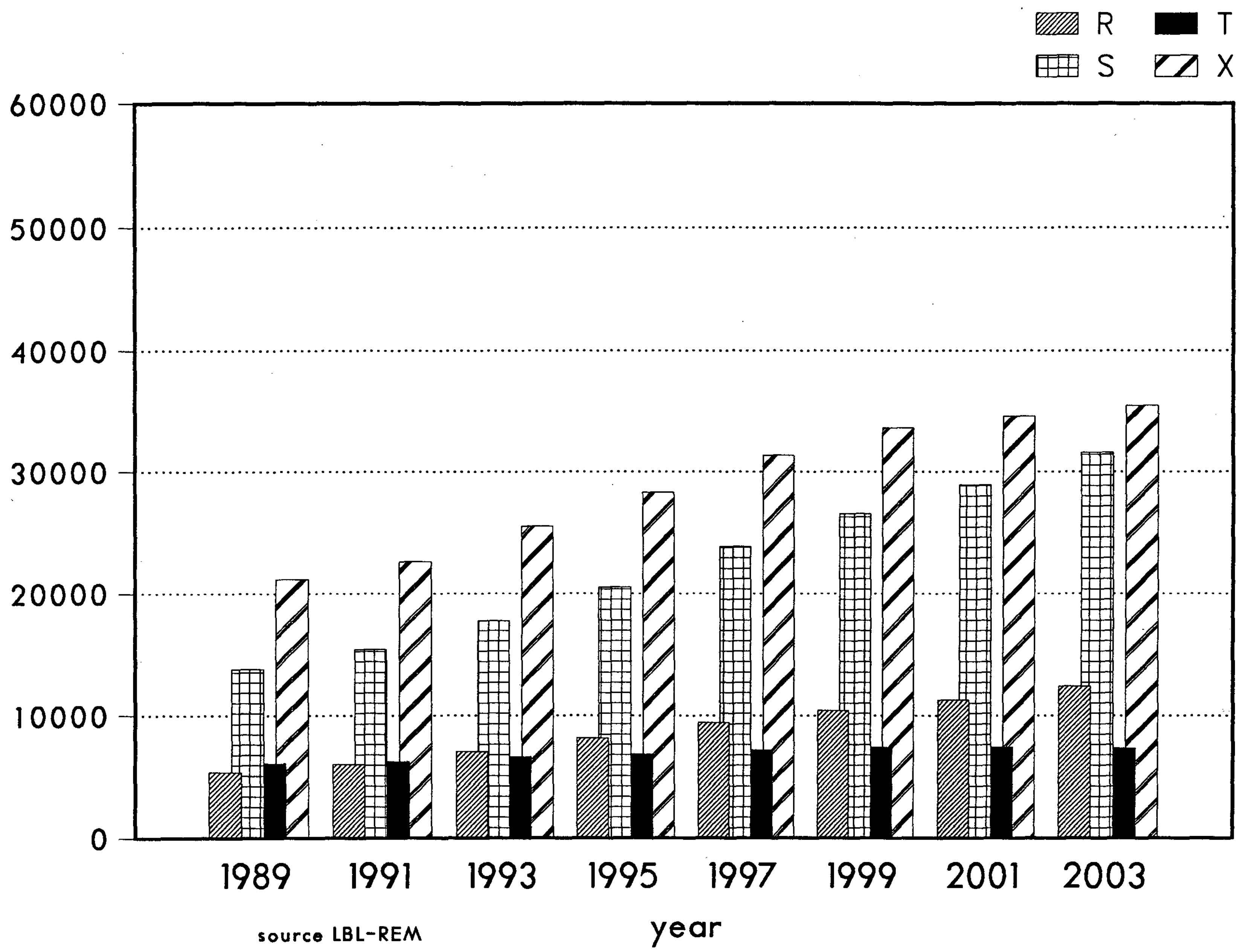


Figure VII.3
Sales of Efficient Room Air Conditioners



source LBL-REM

Figure VII.4
Sales of Efficient Central Air Conditioners

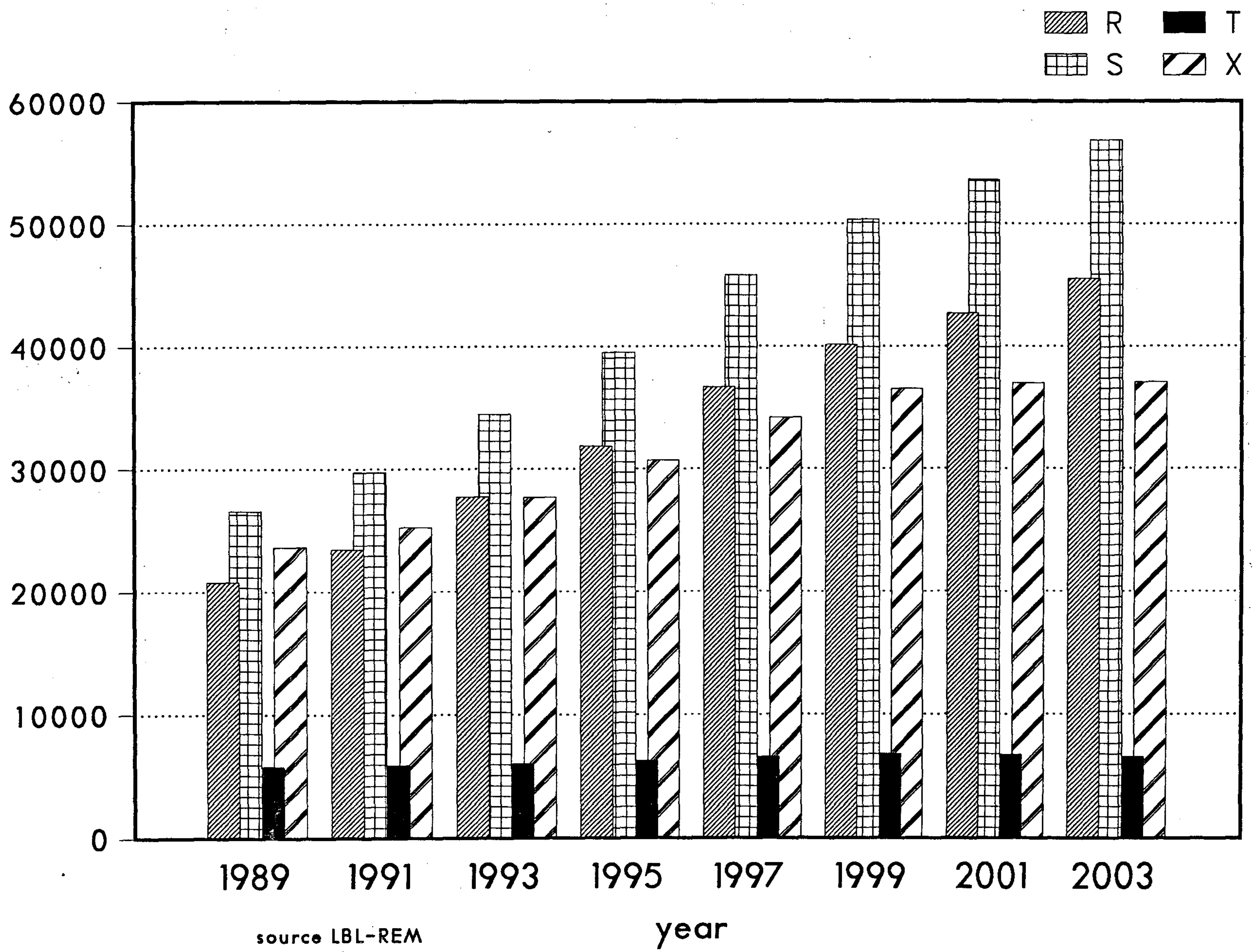


Figure VII.5
Sales of Efficient Heat Pumps

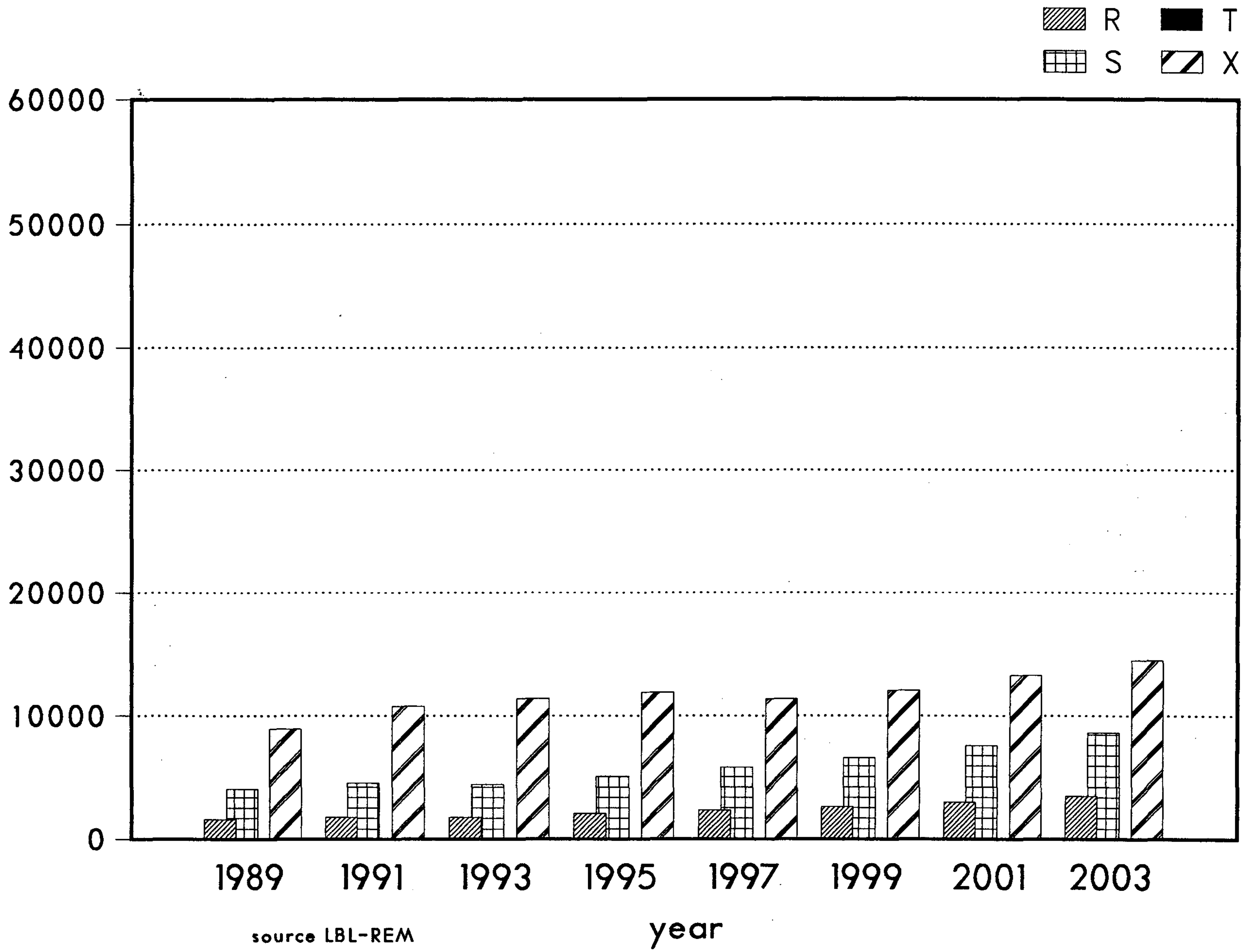
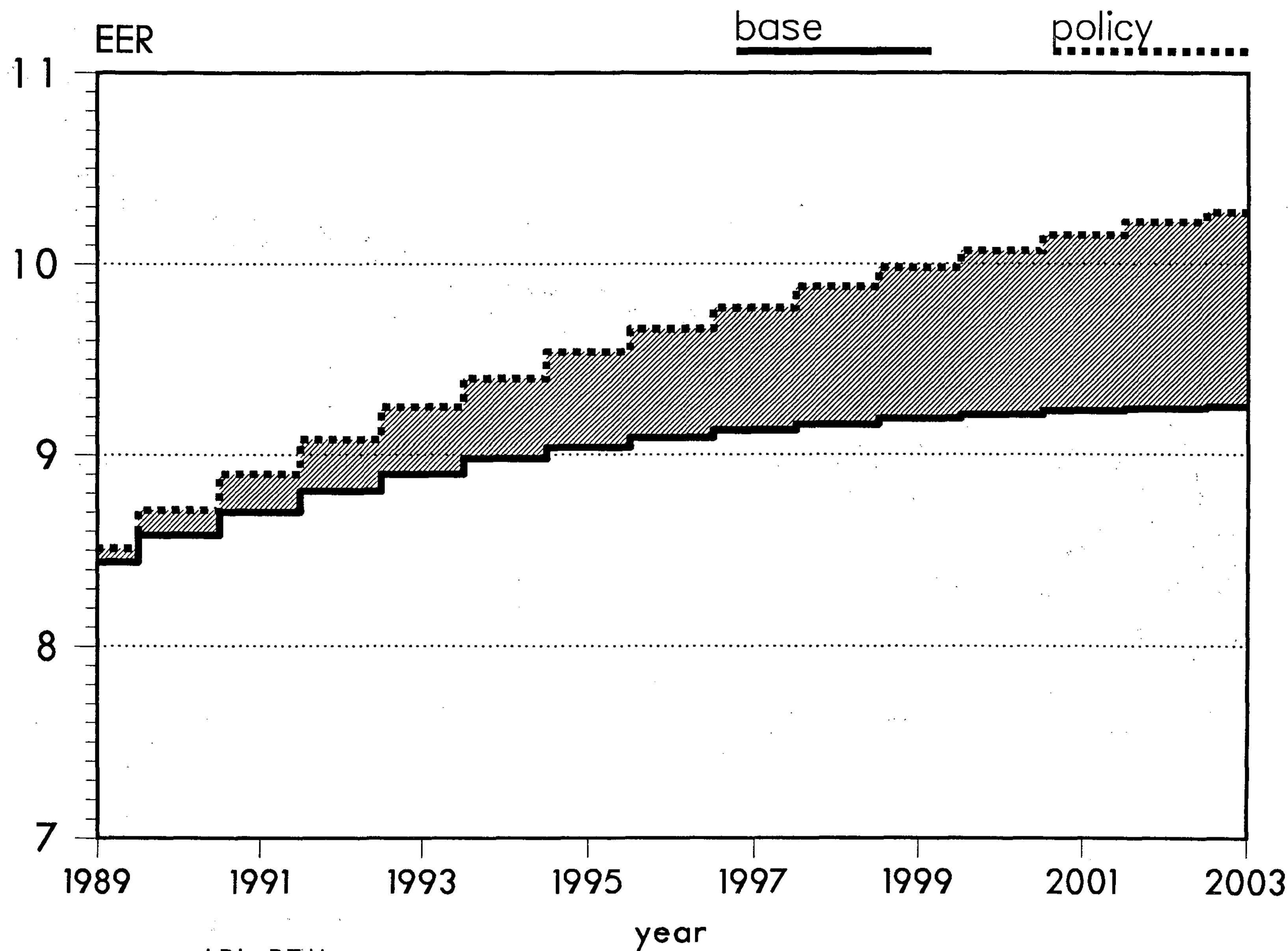
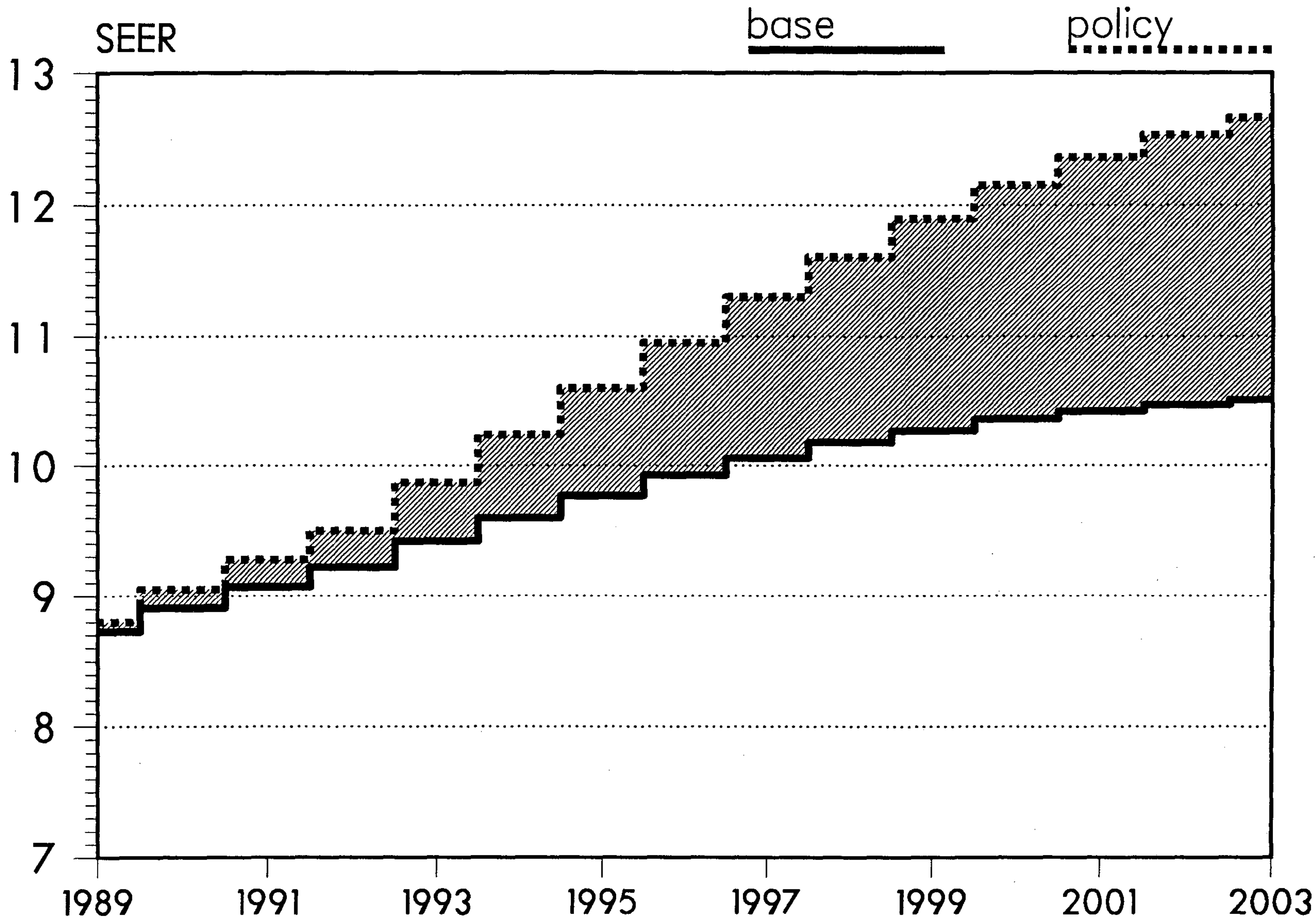


Figure VII.6
Average Efficiency of the Room AC Stock



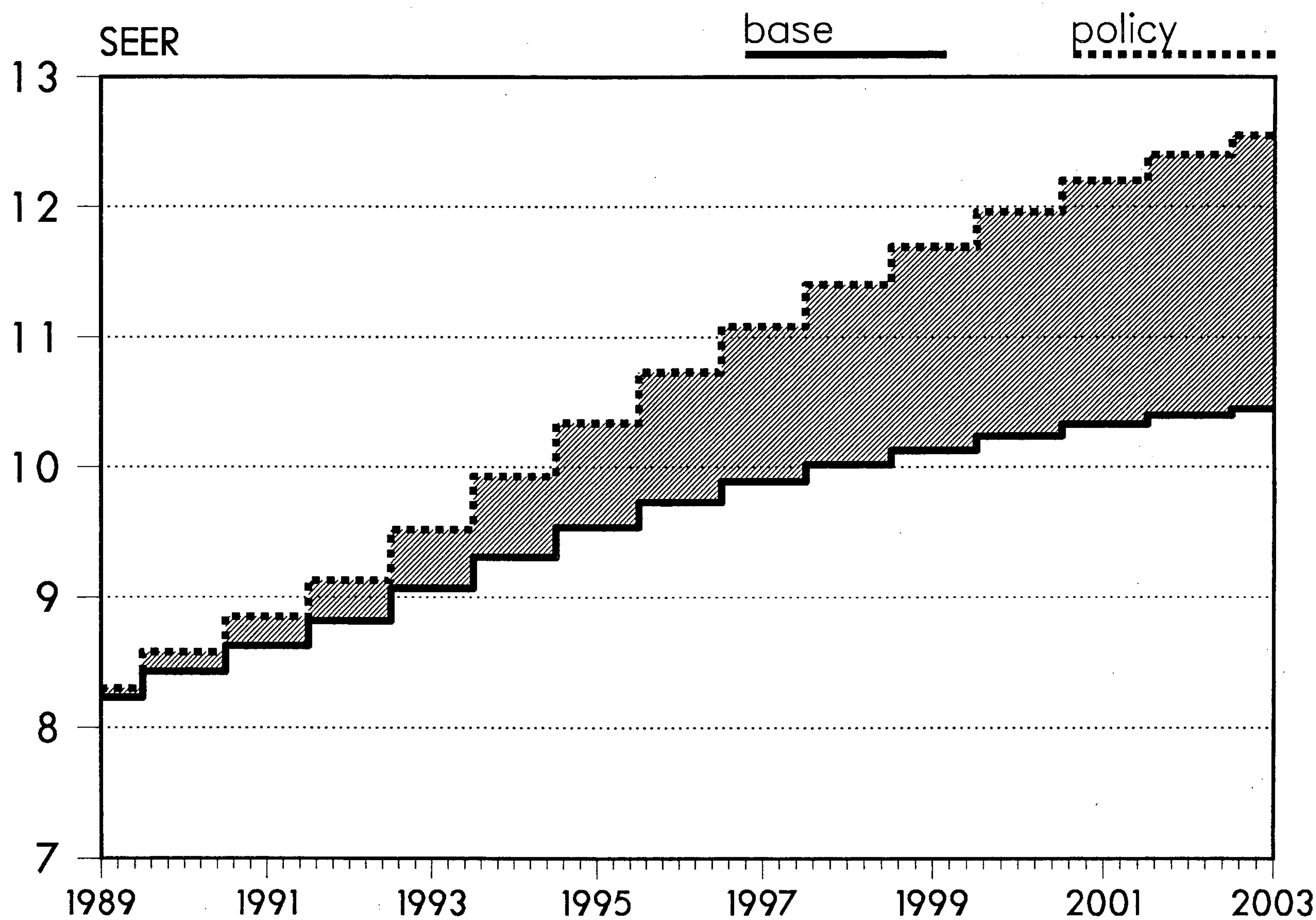
source: LBL-REM

Figure VII.7
Average Efficiency of the Central AC Stock



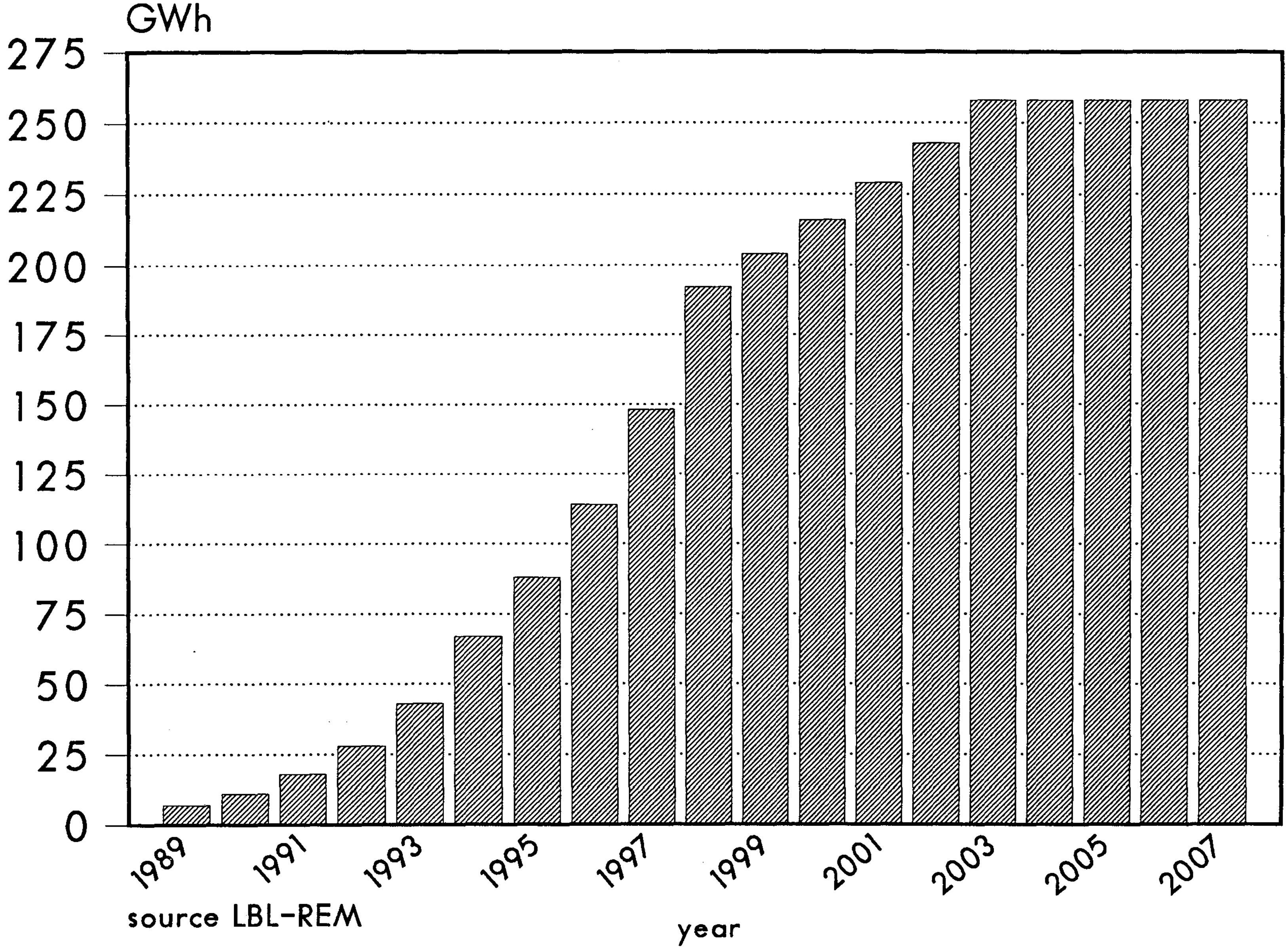
source: LBL-REM

Figure VII.8
Average Efficiency of the Heat Pump Stock



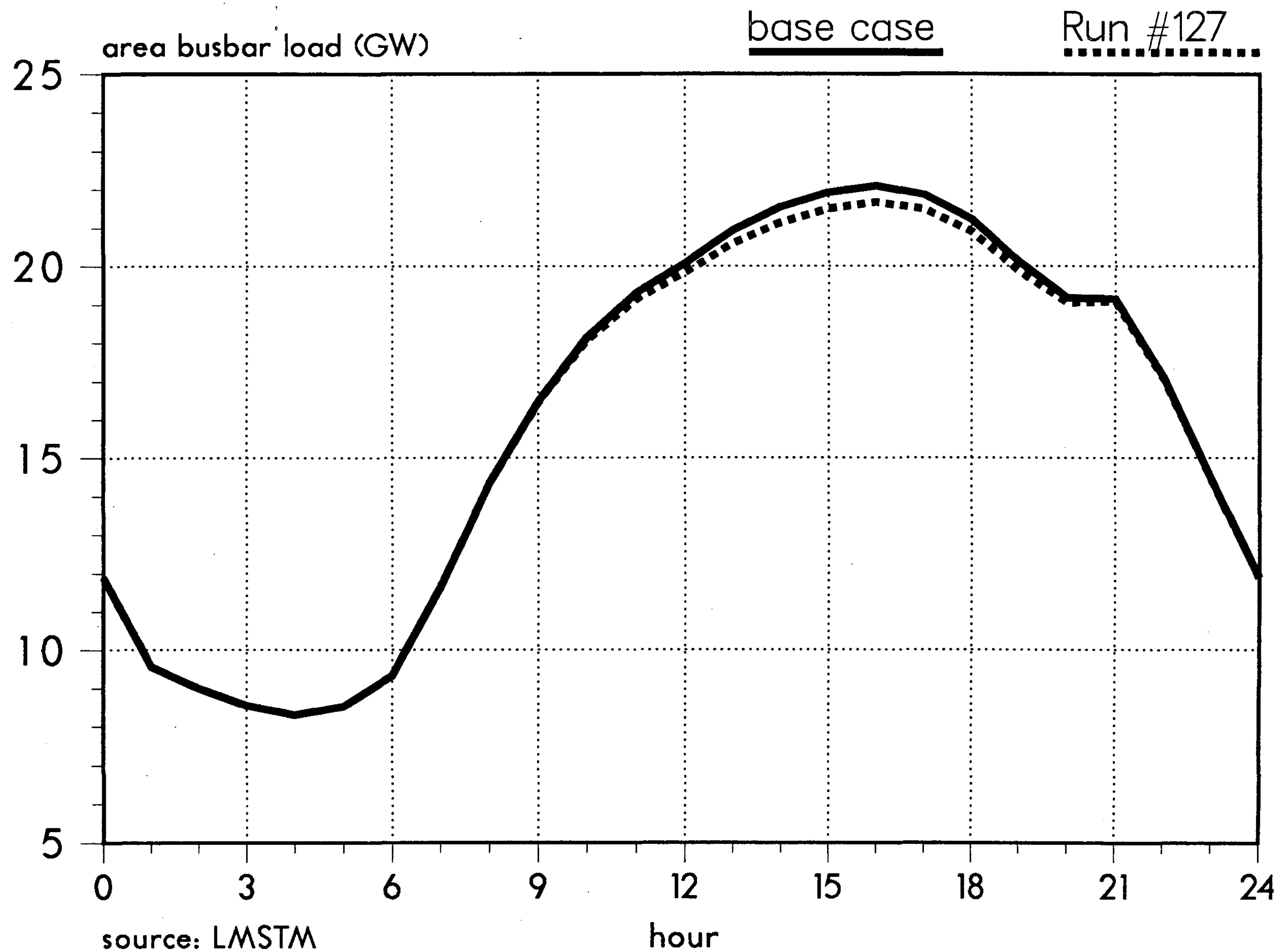
source: LBL-REM

Figure VII.9
Sales Losses under RAC Policy Case



source LBL-REM

Figure VII.10
PGandE System Load Under Base and Policy Cases
(RAC - Summer Extreme Days 2003)



source: LMSTM

Figure VII.11
Sensitivity of Peak Reduction to Hours of Averaging
Residential Air Conditioning Case - Top 500 Hours - Linear Scale

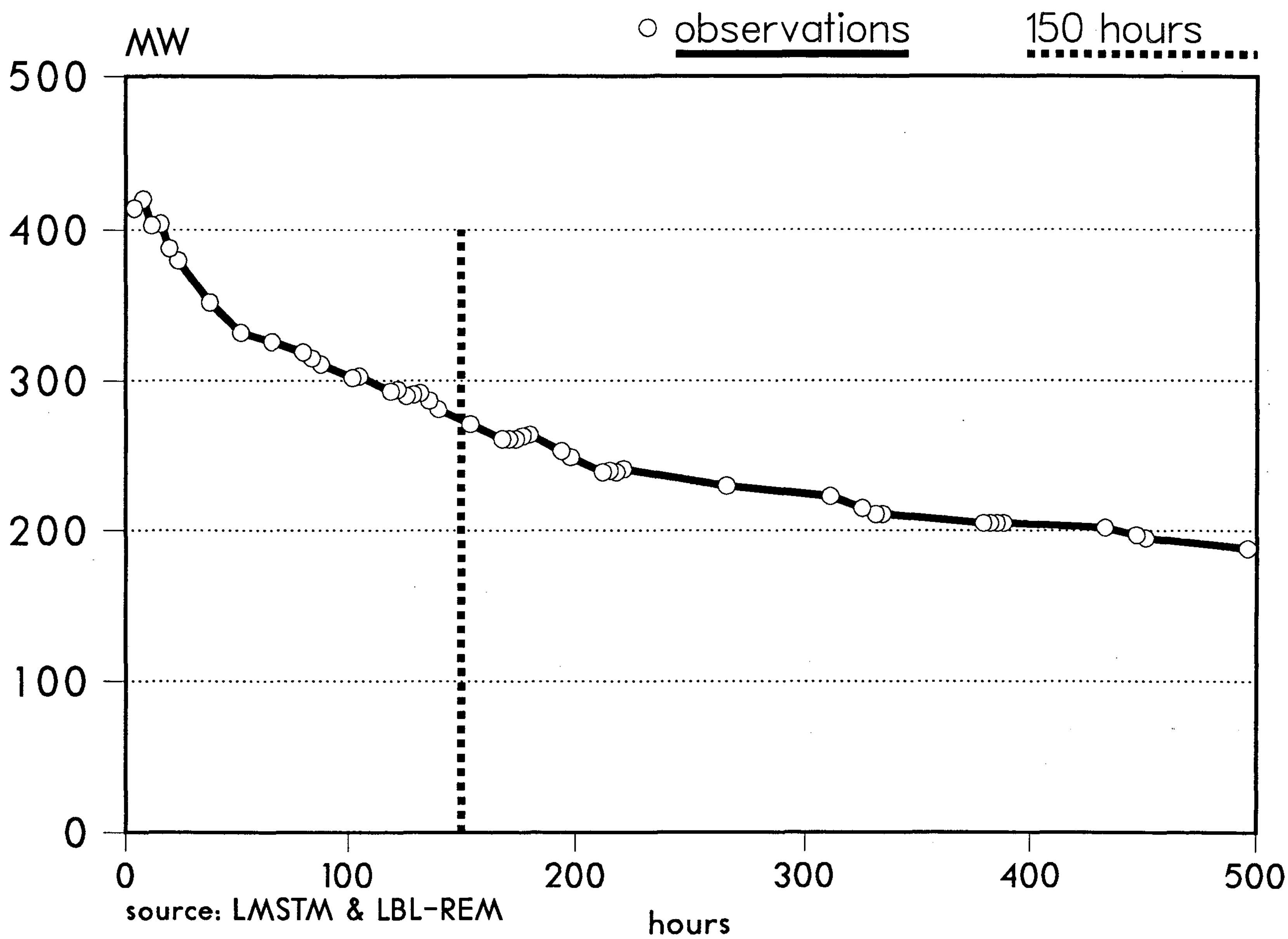
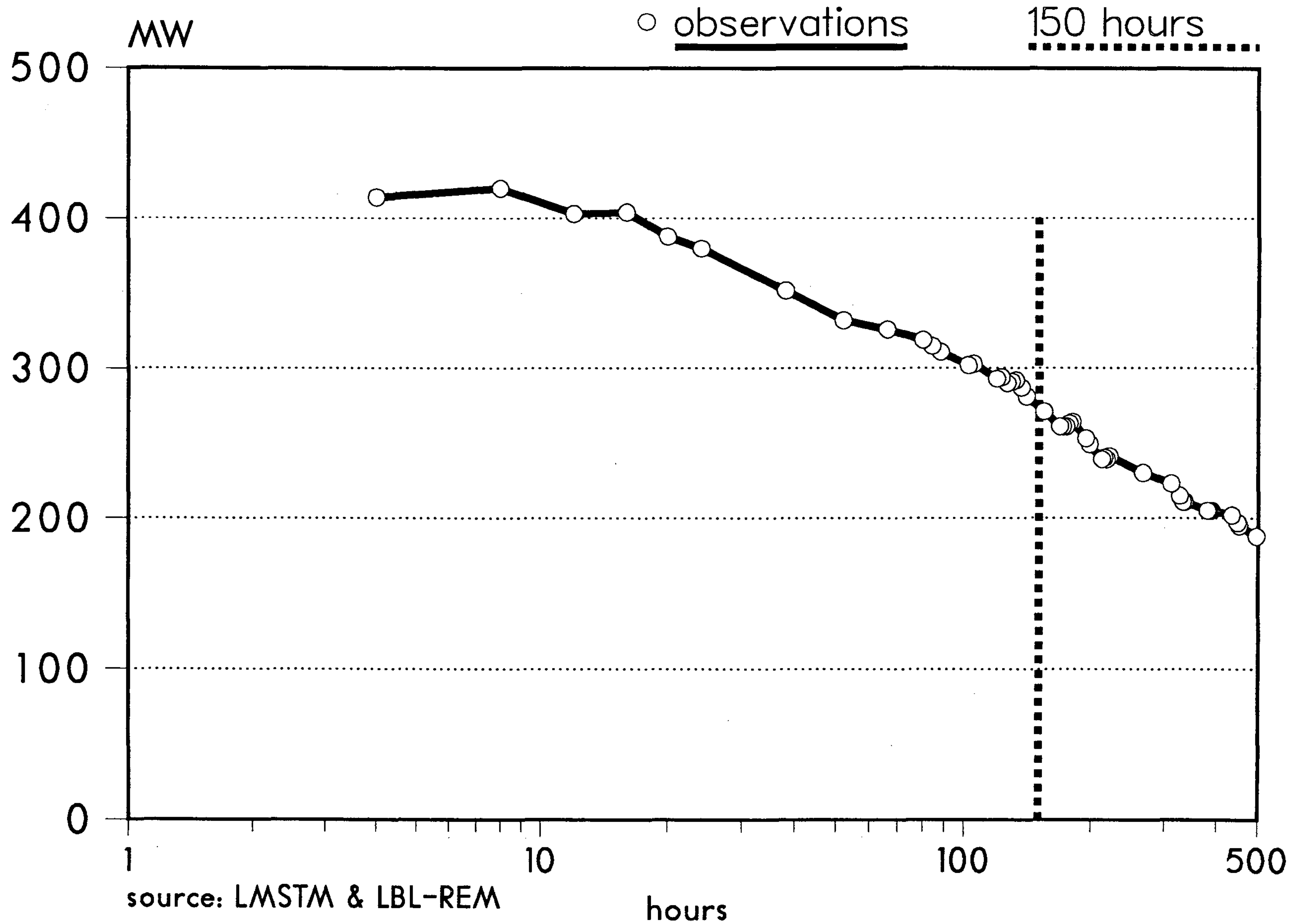


Figure VII.12
Sensitivity of Peak Reduction to Hours of Averaging
Residential Air Conditioning Case - Top 500 Hours - Log scale



source: LMSTM & LBL-REM

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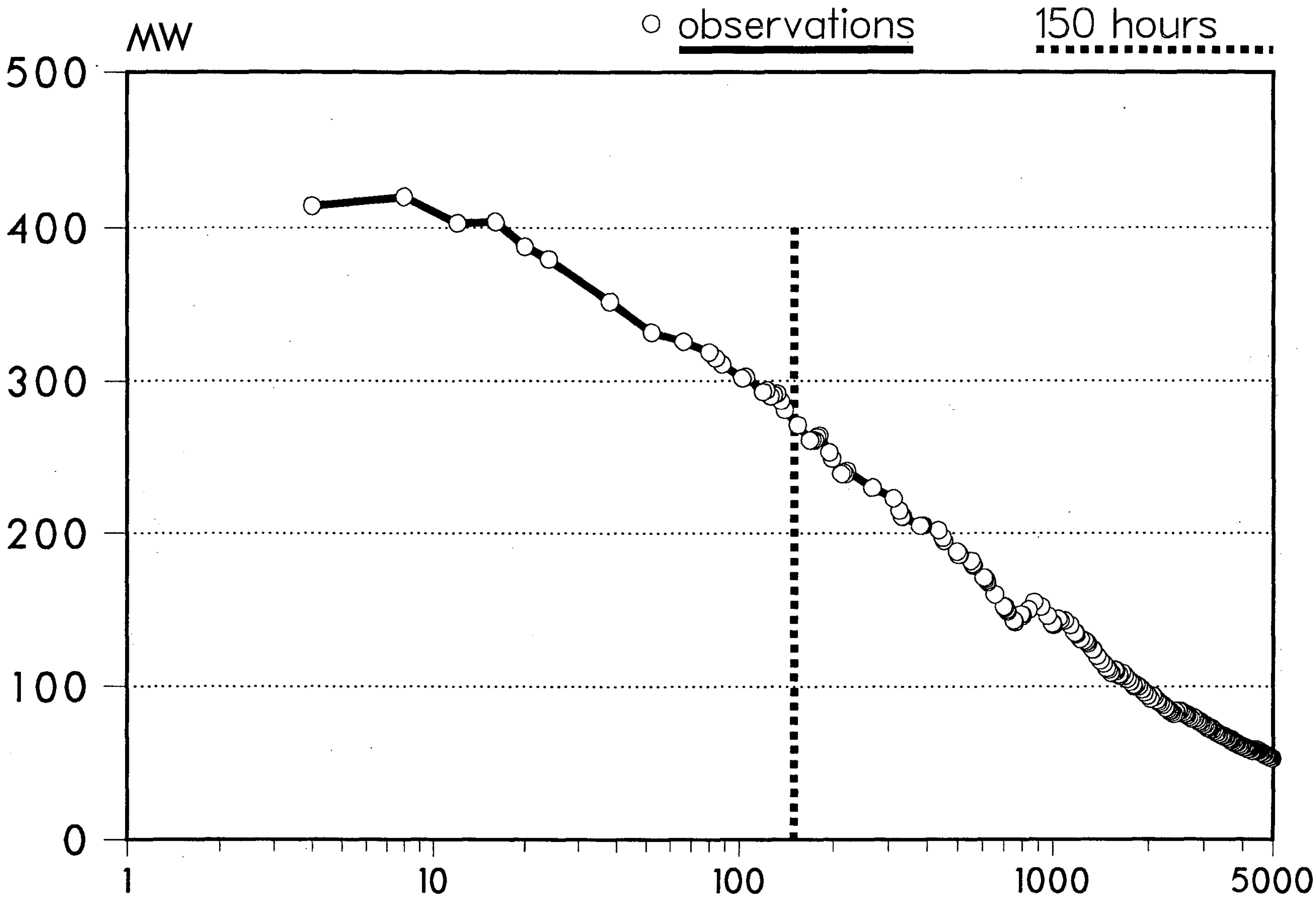
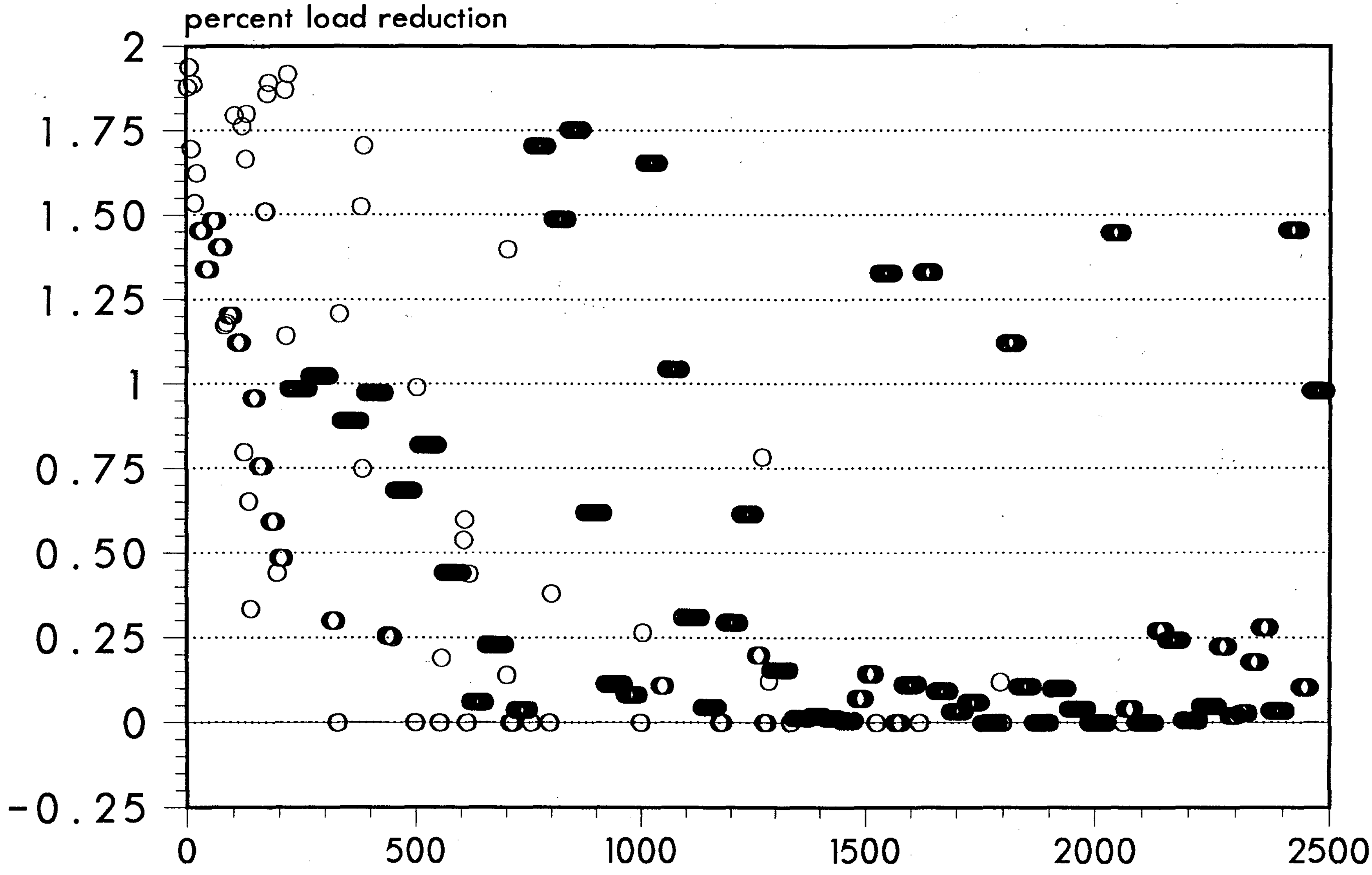
Figure VII.13
Sensitivity of Peak Reduction to Hours of Averaging
Residential Air Conditioning Case - Top 5000 Hours - Log Scale



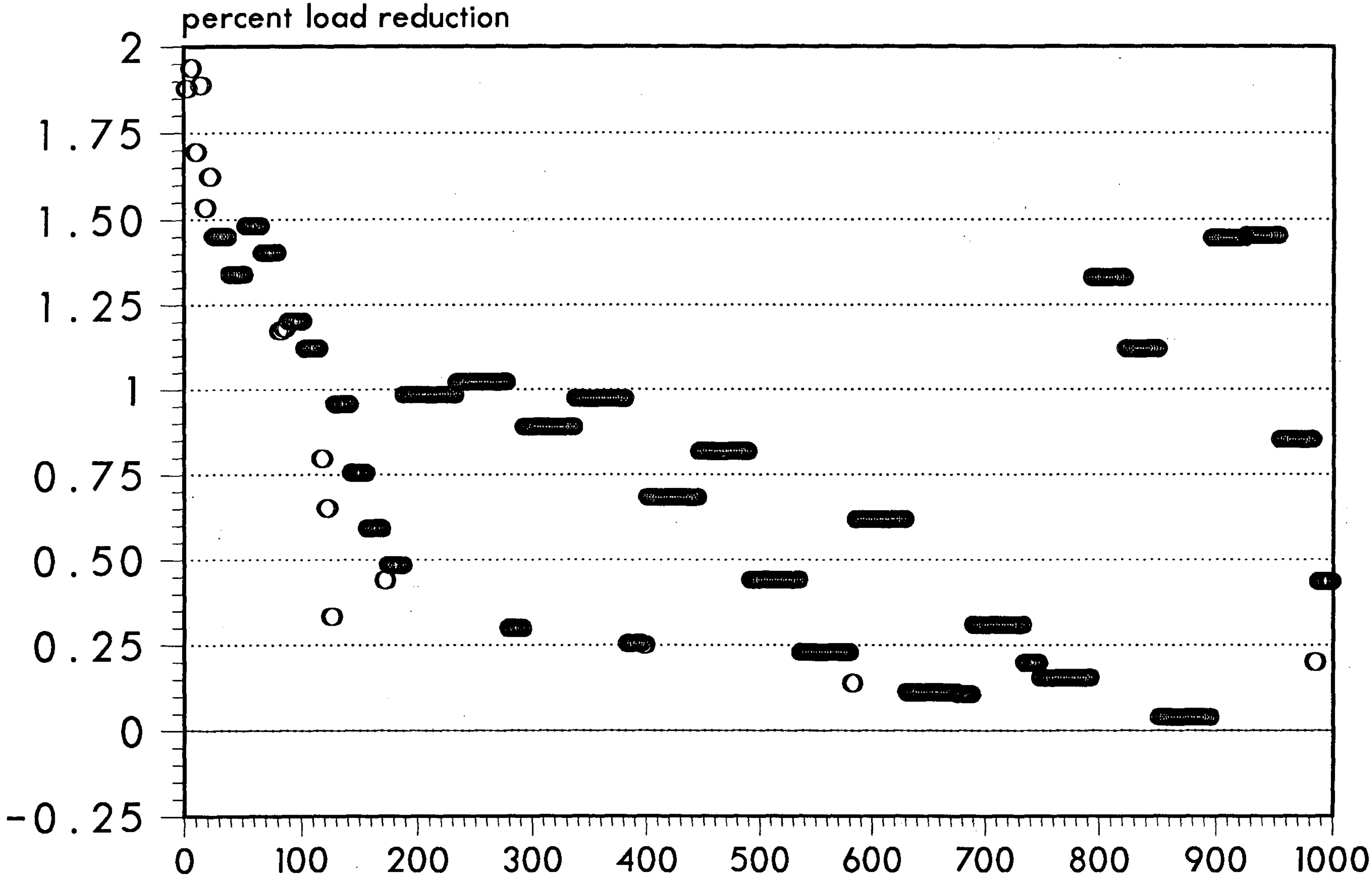
source: LMSTM & LBL-REM

Figure VII.14
Percent Load Reduction Versus Rank of Hourly Load
Residential Air Conditioning Case - ALL 2003



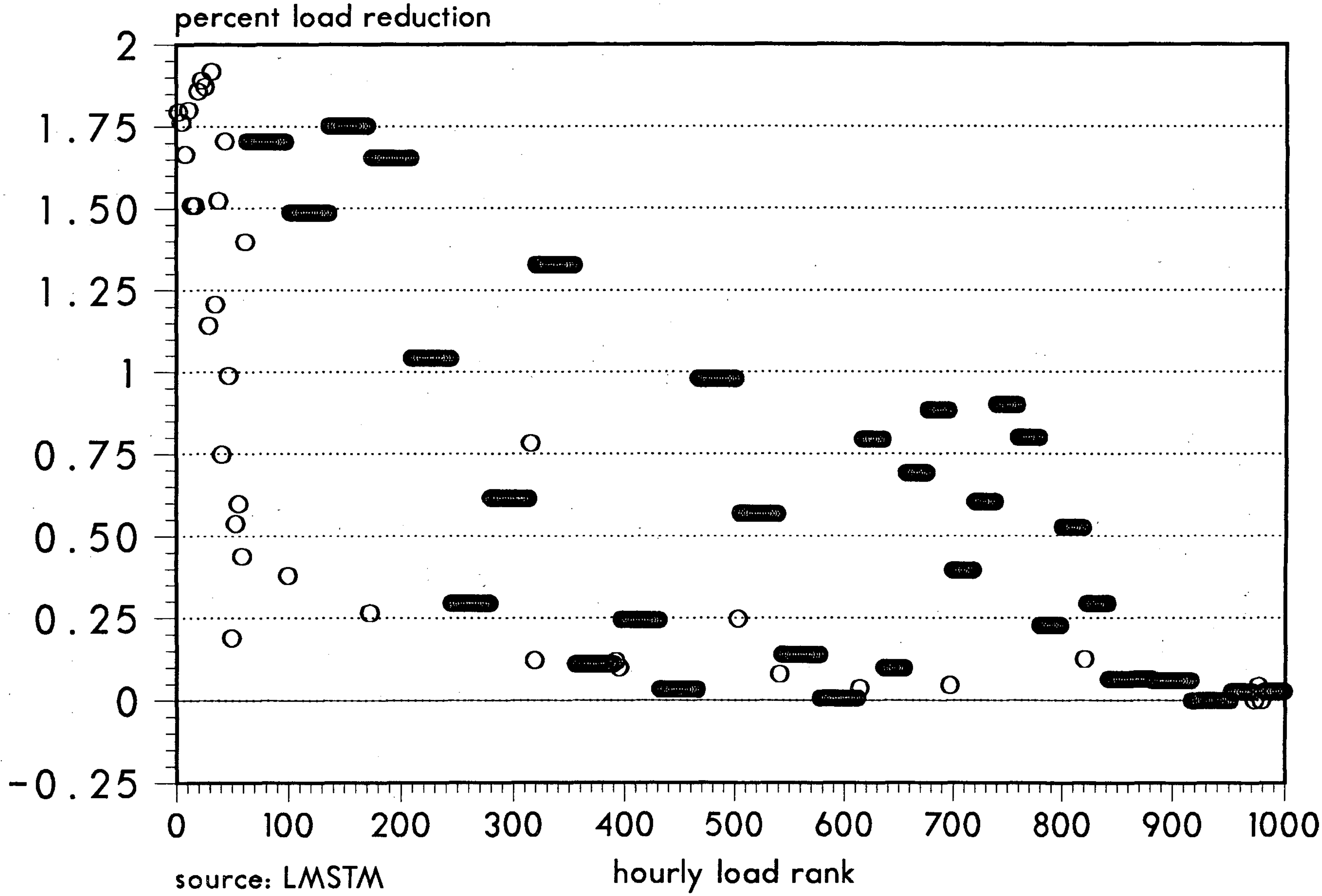
source: LMSTM

Figure VII.15
Percent Load Reduction Versus Rank of Hourly Load
Residential Air Conditioning Case - SUMMER 2003



source: LMSTM

Figure VII.16
Percent Load Reduction Versus Rank of Hourly Load
Residential Air Conditioning Case – SPRING 2003



VIII. CONCLUSION

The two cases studied showed diverse results and illuminated different methodological issues. The analysis of TES begins with an elementary estimation of market penetration, which in the absence of better information is the only approach possible. All results, therefore, rest on assumptions of customer acceptance, as is usually the case in demand-side analysis. The RAC case attempts to couple the sophisticated capabilities of LBL-REM to the policy screening capability of LMSTM. Using LBL-REM gives greater plausibility to estimates of energy and load effects but only at the expense of tricky consistency problems.

Achieving consistency between the models creates special difficulties in three areas. First, the complexity of the PGandE service territory makes it remarkably difficult to achieve a working definition of the system. Ideally the area definition used on the demand side would be identical to the area dispatched by PGandE but this would include the municipals, notably SMUD, and, different rate structures etc. exit in those territories, and modeling chaos results. Second, the outputs of one model are the inputs to the other, and vice-versa, so definitional and formatting problems arise in the transfer between them. Further, since outputs change after each run, iteration is necessary to reach a stable solution. Third, the assumptions actually input should be identical in each model, as well as in any exogenous calculations. Achieving this is more difficult than it sounds when assumptions are embedded deeply in a model's code, and the manual is less than explicit.

The system planner is never likely to plan for the most extreme peak, but will aim to meet average load over a certain number of the top hours. Unfortunately, our results show that the value imputed to the capacity avoided is highly sensitive to the number of hours chosen for averaging. Using 150 hours seems appropriate for the PGandE system, but this assumption is critical in the calculation of capacity values.

Capturing the net benefits from the utility perspective is most difficult because the role of regulation is unpredictable. The working assumption used here is that rates never adjust to the changing circumstances of the utility, that is, it keeps cost savings generated and it loses any revenue reduction that comes about as a result of demand-side changes. This is clearly unrealistic since regulatory adjustments will periodically redistribute the costs and benefits of a program. However, developing a working model of this process is virtually impossible within the context of LCP. In the absense of regulatory influence, estimates of the utility effects are extreme case scenarios and must be seen to be so.

For the two cases studied interesting results were obtained. TES is a winner for customers and society and the results suggest incentives are not needed to accelerate adoption of this emerging technology. The heavy demand charge in the current E20 rate schedule itself provides a strong load shifting incentive. TES could make a valuable load management contribution.

The RAC case is driven by the high customer costs of efficient appliances, and, even then, there is reason to believe they are being underestimated. At a time of capacity expansion, higher oil and gas prices, and, therefore, higher prices for purchase power, this program could be justified, but these conditions are not likely to exist for PGandE until the later years of the study.

The LCP principle is simple, but implementing it is remarkably complex. The experience of this study suggests that comprehensive planning with today's tools and methods is a task beyond the reach of most utility planning departments. Using mainframe models requires the dedication of a significant staff and achieving LCP literacy is a lengthy process. Carrying out analyses requires constant compromises and approximations that in some cases, such as the hours of averaging assumption, can drive results. Given this situation, the closing question of this study must be can one model ever adequately represent this entire process? Certainly, the chances of LCP being reduced to a routine process are slender and the search for the ultimate model appear futile. Further, the concept of LCP rests on assumptions about the industry as a whole that are not likely to hold over time. Notably, the steady infiltration of competition into the industry is eroding the assumption of a vertically integrated monopolistic utility.

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Appendix A

Method of Integrating Historical Load Shapes with Forecasted Load Factors

The basis of the load shapes for the 16 daytypes used in this case study come from measured 1983 PG&E area loads (Kahn *et al.*, 1987). For this case study, however, we want to use a PG&E area forecast based on the latest forecast developed by the California Energy Commission (CEC, 1986). The CEC forecast consists of an energy forecast and a peak-demand forecast. Unfortunately, the load factors in this forecast do not match the load factor embodied in the historical loads and the CEC provides no details about the expected load shapes of their forecast. We wish to combine the load factor information in the CEC forecast with the historical load shapes. A simple and straightforward method is described below.

The historical load data of PG&E is represented in LMSTM using 16 relative hourly load shapes (one for each of the 16 daytypes), energy-use ratios (EUR's) in each of these daytypes, and a total energy demand for the system. By adding a flat load shape to the load shape based on historical data, it is possible to create a new load shape that will match a particular energy and peak-demand forecast. Adding a flat load shape is completely arbitrary. In particular, the impact of adding a flat load will be to change low loads relatively more than high loads and this method makes no consideration of any minimum-load constraint. This method is relatively easy to compute, however, and will keep some of the historical load shape information in the model.

Because we are trying to match a peak-demand forecast, our estimation of the size of the flat load shape will be based on an analysis of the load shape in the daytype where the annual peak demand occurs. For our analysis of the PG&E system, the peak demand will invariably occur in the extreme daytype (daytype 4) of the summer season (season 2). Figure A1.1 shows what the historical load shape on this daytype might look like. Note that the figure as drawn shows *relative* loads, with the peak load equal to 1.0. If we were to make no adjustment to the load factor of the system, a given energy forecast would determine the system peak based on the ratio of the peak load (1.0) to the integral under the load curve ($\sum_{i=1}^{24} l_i$).

If we were to add a completely flat positive load to the historical load that is shown in Figure A1.1, the addition of the two load shapes would result in a shape that would look flatter. If we were to add a negative flat load, the net load would look more spiked. Because the historical loads have higher load factors than the forecasted loads, adding a negative flat load is the appropriate thing to do.

Given the historical load shapes and a simple flat load, we can write a pair of equations that will meet the energy and peak-demand forecast for a particular year:

$$\frac{a \sum_{i=1}^{24} l_i + 24\, b}{f_{2,4}} = E \qquad \text{A1.1}$$

$$a + b = P \qquad \text{A1.2}$$

where:

i	= hour
a	= parameter (GW) equal to peak load of historical load shape before addition of flat load shape
b	= parameter (GW) equal to the magnitude of the flat load in any hour i
l_i	= relative hourly load of summer extreme daytype; highest hourly load is equal to 1
E	= forecasted yearly energy demand (GWh)
$f_{2,4}$	= fraction of yearly energy, E, demanded in one day of daytype 4 (extreme), season 2 (summer)
	= $EUR_{2,4}/\overline{EUR}/365$
EUR	= energy use ratio for an LMSTM daytype
$\overline{EUR}$	= average EUR for year (must weight each EUR by number of days in daytype)
P	= forecasted yearly system peak demand (GW)

While we want to meet a particular energy and peak demand forecast, LMSTM requires for each daytype a relative load shape and the total energy used by that daytype. Thus, what is needed from the above relationships is a solution to a and b for the extreme summer daytype. All of the other information in Equations A1.1 and A1.2 are known from the historical load shapes, the historical EUR's, and the energy and peak-demand forecast. Because the forecasted energy and peak demand grow over time (and at different rates) a solution for a and b is needed for every year. The following shows the solution for a and b for any year, j:

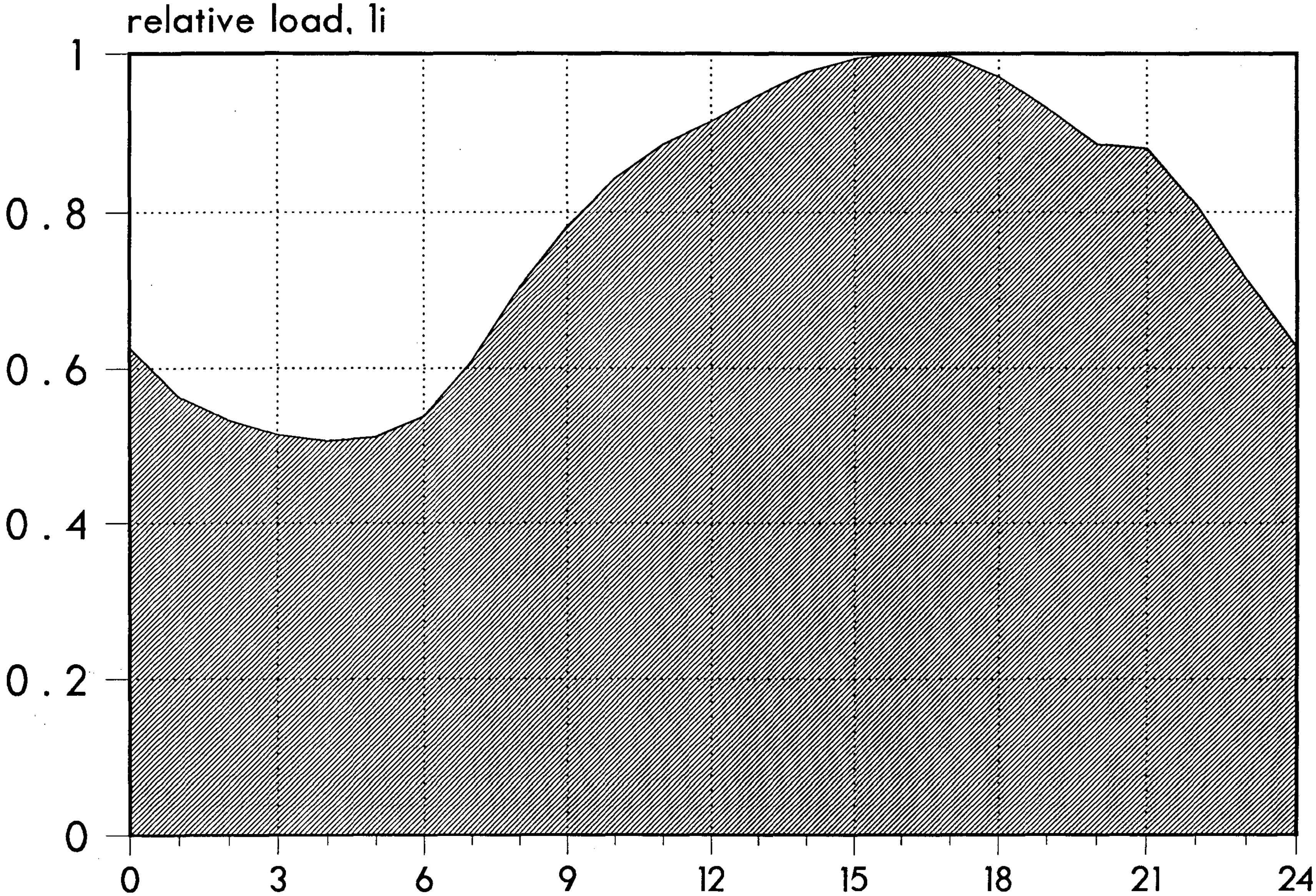
$$b_j = \frac{E_j\, f_{2,4} - P_j \sum_{i=1}^{24} l_i}{24 - \sum_{i=1}^{24} l_i} \qquad \text{A1.3}$$

$$a_j = P_j - b_j \qquad \text{A1.4}$$

Equations A1.3 and A1.4 show which variables vary over the years and which do not. As noted above, the energy and peak-demand forecasts vary over the years. The fraction of the peak-load-daytype energy use to total energy use, $f_{2,4}$, and the historical load shape (represented in Equation A1.3 as $\sum_{i=1}^{24} l_i$) do not vary over the years.

The above transformation of the peak summer daytype load shape may be easily extended to the other 16 daytypes. The value of a and b are the same. LMSTM's EUR's properly adjust the energy use in each of the 16 daytypes. For simplicity, we assume that the EUR's associated with a and b are exactly the same as the historical EUR's.

Figure A1.1
LMSTM Load Shape Input - Summer Extreme Day



source: PGandE load data file

Appendix B

Weather Consistency in Constituent Models

At this level of analysis, weather becomes a vexing problem in several ways. One concerns the consistency between the weather embodied in the LMSTM inputs and the explicit weather input to LBL-REM. It would be most desirable to have weather tapes on hand for the same year that the LMSTM system load shapes are based on, for a wide range of sites in the service territory, enough to capture the main climatic variations. The load decrements calculated by LBL-REM and the LBL Hourly Model could then be dated and exactly correlated to the days that were previously assigned to each of the daytypes. Or even better, the entire procedure should be run for several years with varying weather and some type of long run mean and variance estimated. In practice, neither of these alternatives is practical. The number of weather tapes and runs needed would soon exceed the modelers' ability to keep track. In this study, four weather sites are used, one for each of the rate regions studied. Fresno for the R region, Sacramento for S, Oakland for T, and San Jose for X. The data used are Climatological Zone (CTZ) weather tapes in each case. These are tapes of representative weather years chosen by the California Energy Commission to provide representative data for the state's various climatic areas. Unfortunately, using different weather tapes for different parts of the modeling introduces several inconsistencies. First, LBL-REM does not distinguish between weekdays and weekends for the purposes of residential air conditioning simulation, so no equivalent to the LMSTM *weekend* daytype exists. This problem was sidestepped by picking every sixth and seventh day from the LBL-REM output and calling it a "weekend." Second, as described in the stage 1 report, the definitions of the *extreme*, *peak*, and *normal* daytypes was based on system output for the day. For each season, a matrix of system days was stacked from highest to lowest system output and then the matrix is split at the appropriate points to ensure the correct number of days is averaged for each daytype. The same procedure is followed with the system decrements from the LBL-REM, the variable used for ordering being the days' total residential sales. However, there is no way to determine how well the high residential usage days correspond to the high system output days. In other words, is most electricity used in the residential sector on the same days the most is used elsewhere? In hot weather, which, luckily, is the time of most interest for this study, the answer is most likely yes, and this is the assumption used.

Table A2.1 shows a simple analysis of how average the CTZ tapes used and the 1983 weather that drives the base case LMSTM load shapes compare to some published average weather data. Two caveats to the analysis should, however, be mentioned. First, the low humidity of California weather tends to raise the comfortable temperature range so that air conditioning is often not used until temperatures are high by the standards of other locales. Numbers of cooling degree days (CDD) with bases of 65, or even 75 ^{o}F, are not excellent predictors of cooling load in this area. And, second, the low number of CDD in the cooler areas will naturally tend to produce higher variances year to year that will occur in the hotter areas. The most glaring irregularity is in the T region, for which CDD are 95% above normal, and the CTZ tape for

Oakland shows 66% more CDD than average for SFO. Luckily, T accounts for a small fraction of the total cooling load, so the effect of this inconsistency on final results is probably not great. The X region data, based on San Jose airport, is also somewhat disturbing, given the importance of this region. First, 1983 weather shows 36% more CDD than the long run average, which might be a significant factor, given the dominant role of X in LBL-REM's energy use. However, the CTZ CDD for the months the airport was able to report was in reasonable agreement with the airport data. Also, a significant number of CDD come in other months, over 40 % in the CTZ year for San Jose, and so the comparisons presented, based only on three months may be inaccurate. The remaining two regions, R and S, show good agreement between 1983 weather and CTZ weather, and the only cause for concern is that both are hotter than the long run average data.

Table A2.1
Comparison of 1983 Cooling Degree Days to Average

region	station	1983	CTZ	average	1983/average	CTZ/average
R	Fresno	2068	2076	1952	1.06	1.06
S	Sacto.	1263	1296	1237	1.02	1.05
T	SFO/Oak.	282	238	144	1.95	1.66
X	San Jose	644	776	475	1.36	0.94

cooling degree days base 65^{o}F
for region T, average & 1983 is SFO, CTZ is Oak.
source: National Oceanic & Atmospheric Admin.,
except, San Jose data from S.J. airport
S.J. data is for July-Sept. only

The demand-side program load information is in the same form as the base-case loads--one shape for each of the 16 daytypes--except that the program is a set of negative and positive incremental loads rather than absolute loads. LMSTM distributes the total energy impact accross the daytypes according to the proportions of 16 energy-use ratios (EUR's). Thus, any demand-side program can be represented as 16 incremental load shapes, 16 EURs, and a total energy impact.

Appendix C

EVALER Sensitivities for TES Case

The following summarizes the EVALER runs that are presented in Section VI. All sensitivities are based on LMSTM runs #120 (policy) and #115 (base). Note that not every sensitivity corresponds to a unique EVALER run. For example, finding the revenue loss where the utility cost benefit ''breaks-even'' can be done manually.

Summary of sensitivities:

Sensitivity:Description:

0. Primary sensitivity. Ten percent discount rate used for all perspectives to obtain results for societal-perspective table.
1. Utility discount rate set to pre-tax WACC. Used for sensitivity A of utility-perspective table.
2. Not used.
3. Utility discount rate set to pre-tax WACC. Effect of direct incentives by utility is added. This is done by decreasing avoided capacity value to utility and decreasing incremental cost to TES adopter. Used for sensitivity A of utility-perspective table.
4. Utility discount rate set to pre-tax WACC. Effect of direct incentives is added. Revenue-loss factor decreased until after-incentive net benefit to utility is zero. Used for sensitivity B of utility-perspective table.
5. Not used.
6. Ten percent discount rate used for all perspectives to obtain results for societal-perspective table. Incremental cost to TES adopter increased until societal benefit is zero. Used for sensitivity B of societal-sensitivity table.
7. Ten percent discount rate used for all perspectives to obtain results for societal-perspective table. Value of avoided capacity to utility increased to $725/kW. Incremental cost to TES adopter increased until societal benefit is zero. Used for sensitivity C of societal-sensitivity table.
8. Utility discount rate set to pre-tax WACC. Value of avoided capacity to utility increased to $725/kW. Revenue-loss factor decreased until pre-incentive net benefit to utility is zero. Used for sensitivity C and D of utility-perspective table.

BASIC ASSUMPTIONS

number of hours of peak averaging:	150.00
utility discount rate (curr):	10.00
customer discount rate (curr):	10.00
societal discount rate (curr):	10.00
general inflation rate :	5.00
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	10.23
PGandE capacity cost (1987$/kW) :	320.00
rac customer cap. cost (1987$/kW) :	.00
tes customer cap. cost (1987$/kW) :	239.00
TES revenue loss factor (1987$/kW) :	89.00
sensitivity factor for pksavs.n :	1.20
sens. factor for modest deferrals :	1.27

1

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	.0	-1.9	.0	.0	.0	.0	.2	.0	.2	.2	-.0	.2	.2	.0	.0	.2	.2	.2	.2
1990	.0	-2.6	19.2	.0	.0	2.3	.2	7.1	5.1	3.8	-.0	-2.1	-1.5	-3.1	-2.3	2.0	1.5	-5.1	-3.8
1991	.0	-3.7	38.5	-.0	.0	4.8	.4	7.5	3.1	2.1	-.1	-4.5	-3.1	-.8	-.6	2.3	1.6	-5.3	-3.6
1992	.0	-5.1	58.1	.0	.0	7.0	.6	8.0	1.6	1.0	-.3	-6.7	-4.2	1.1	.7	2.6	1.6	-5.6	-3.5
1993	.0	-7.1	77.8	.0	.0	9.8	.9	8.4	-.4	-.2	-.6	-9.5	-5.4	3.5	2.0	3.0	1.7	-6.0	-3.4
1994	.0	-9.8	113.9	-.7	.0	14.8	1.4	16.3	2.8	1.5	-.5	-13.9	-7.1	2.7	1.4	5.5	2.8	-11.3	-5.8
1995	.0	-13.7	150.0	-.6	.0	21.0	2.3	17.1	-1.6	-.8	-.9	-19.6	-9.1	8.3	3.9	6.6	3.1	-11.3	-5.3
1996	.0	-19.0	179.2	-.6	.0	26.2	9.5	14.5	-2.2	-.9	31.2	14.5	6.2	15.4	6.5	13.2	5.6	29.9	12.7
1997	.0	-19.0	208.3	-.9	.0	31.6	10.7	15.2	-5.7	-2.2	30.2	9.3	3.6	20.2	7.8	14.5	5.6	29.6	11.4
1998	.0	-19.0	208.4	-.8	.0	33.2	12.2	.1	-20.9	-7.3	29.2	8.2	2.9	33.1	11.6	12.2	4.3	41.4	14.5
1999	.0	-19.0	208.7	-.9	.0	35.8	13.4	.1	-22.2	-7.1	28.6	6.2	2.0	35.7	11.4	13.4	4.3	41.9	13.3
2000	.0	-19.0	208.6	-.8	.0	38.7	14.9	-.1	-23.9	-6.9	27.8	4.0	1.2	38.7	11.2	14.9	4.3	42.8	12.4
2001	.0	-19.0	208.6	-.9	.0	42.1	17.5	.0	-24.6	-6.5	27.1	2.5	.7	42.1	11.1	17.5	4.6	44.6	11.7
2002	.0	-19.0	208.7	-.9	.0	45.7	20.2	.1	-25.4	-6.1	26.7	1.1	.3	45.7	10.9	20.2	4.8	46.8	11.2
2003	.0	-19.0	208.8	-.7	.0	49.9	21.6	.1	-28.2	-6.1	25.9	-2.4	-.5	49.8	10.8	21.6	4.7	47.4	10.3
2004	.0	-19.0	208.8	-.7	.0	52.4	23.6	.0	-28.8	-5.7	25.1	-3.7	-.7	52.4	10.4	23.6	4.7	48.7	9.6
2005	.0	-19.0	208.8	-.6	.0	55.0	26.6	.0	-28.4	-5.1	24.4	-4.0	-.7	55.0	9.9	26.6	4.8	51.0	9.2
2006	.0	-19.0	208.8	-.5	.0	57.8	29.6	.0	-28.2	-4.6	23.7	-4.4	-.7	57.8	9.4	29.6	4.8	53.3	8.7
2007	.0	-19.0	208.8	-.4	.0	60.7	33.8	.0	-26.9	-4.0	22.7	-4.1	-.6	60.7	9.0	33.8	5.0	56.5	8.4
5-yr horizon (to 1992):					.0	9.3	1.0	15.4		7.1	-.2		-8.6		-2.2		4.9		-10.8
10-yr horizon (to 1997):					.0	55.6	11.4	48.5		4.4	23.6		-20.5		19.3		23.7		-1.2
15-yr horizon (to 2002):					.0	111.8	33.7	48.6		-29.5	64.5		-13.6		75.5		46.0		62.0
20-yr horizon (to 2007):					.0	161.4	57.7	48.6		-55.1	86.8		-16.9		125.1		70.0		108.2
27-yr horizon (to 2014):					.0	213.6	86.8	48.6		-78.2	106.3		-20.4		177.3		99.1		156.9
30-yr horizon (to 2017):					.0	231.0	96.5	48.6		-85.9	112.9		-21.6		194.7		108.8		173.1
40-yr horizon (to 2027):					.0	273.8	120.4	48.6		-104.8	128.9		-24.5		237.5		132.7		213.0

All time horizons count 1987 as year 0. Beyond 2007 the benefit stream is assumed flat at the 2007 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

Sensitivity 0

BASIC ASSUMPTIONS

number of hours of peak averaging:	150.00
utility discount rate (curr):	10.40
customer discount rate (curr):	8.00
societal discount rate (curr):	10.00
general inflation rate :	5.00
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	10.23
PGandE capacity cost (1987$/kW) :	320.00
rac customer cap. cost (1987$/kW) :	.00
tes customer cap. cost (1987$/kW) :	239.00
TES revenue loss factor (1987$/kW) :	89.00
sensitivity factor for pksavs.n :	1.20
sens. factor for modest deferrals :	1.27

1

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	.0	-1.9	.0	.0	.0	.0	.2	.0	.2	.2	-.0	.2	.2	.0	.0	.2	.2	.2	.2
1990	.0	-2.6	19.2	.0	.0	2.3	.2	7.1	5.1	3.8	-.0	-2.1	-1.5	-3.1	-2.4	2.0	1.5	-5.1	-3.8
1991	.0	-3.7	38.5	-.0	.0	4.8	.4	7.5	3.1	2.1	-.1	-4.5	-3.0	-.8	-.6	2.3	1.6	-5.3	-3.6
1992	.0	-5.1	58.1	.0	.0	7.0	.6	8.0	1.6	.9	-.3	-6.7	-4.1	1.1	.7	2.6	1.6	-5.6	-3.5
C-3 1993	.0	-7.1	77.8	.0	.0	9.8	.9	8.4	-.4	-.2	-.6	-9.5	-5.2	3.5	2.2	3.0	1.7	-6.0	-3.4
1994	.0	-9.8	113.9	-.7	.0	14.8	1.4	16.3	2.8	1.4	-.5	-13.9	-7.0	2.7	1.6	5.5	2.8	-11.3	-5.8
1995	.0	-13.7	150.0	-.6	.0	21.0	2.3	17.1	-1.6	-.7	-.9	-19.6	-8.9	8.3	4.5	6.6	3.1	-11.3	-5.3
1996	.0	-19.0	179.2	-.6	.0	26.2	9.5	14.5	-2.2	-.9	31.2	14.5	6.0	15.4	7.7	13.2	5.6	29.9	12.7
1997	.0	-19.0	208.3	-.9	.0	31.6	10.7	15.2	-5.7	-2.1	30.2	9.3	3.5	20.2	9.4	14.5	5.6	29.6	11.4
1998	.0	-19.0	208.4	-.8	.0	33.2	12.2	.1	-20.9	-7.0	29.2	8.2	2.8	33.1	14.2	12.2	4.3	41.4	14.5
1999	.0	-19.0	208.7	-.9	.0	35.8	13.4	.1	-22.2	-6.8	28.6	6.2	1.9	35.7	14.2	13.4	4.3	41.9	13.3
2000	.0	-19.0	208.6	-.8	.0	38.7	14.9	-.1	-23.9	-6.6	27.8	4.0	1.1	38.7	14.2	14.9	4.3	42.8	12.4
2001	.0	-19.0	208.6	-.9	.0	42.1	17.5	.0	-24.6	-6.1	27.1	2.5	.6	42.1	14.3	17.5	4.6	44.6	11.7
2002	.0	-19.0	208.7	-.9	.0	45.7	20.2	.1	-25.4	-5.8	26.7	1.1	.3	45.7	14.4	20.2	4.8	46.8	11.2
2003	.0	-19.0	208.8	-.7	.0	49.9	21.6	.1	-28.2	-5.8	25.9	-2.4	-.5	49.8	14.5	21.6	4.7	47.4	10.3
2004	.0	-19.0	208.8	-.7	.0	52.4	23.6	.0	-28.8	-5.4	25.1	-3.7	-.7	52.4	14.2	23.6	4.7	48.7	9.6
2005	.0	-19.0	208.8	-.6	.0	55.0	26.6	.0	-28.4	-4.8	24.4	-4.0	-.7	55.0	13.8	26.6	4.8	51.0	9.2
2006	.0	-19.0	208.8	-.5	.0	57.8	29.6	.0	-28.2	-4.3	23.7	-4.4	-.7	57.8	13.4	29.6	4.8	53.3	8.7
2007	.0	-19.0	208.8	-.4	.0	60.7	33.8	.0	-26.9	-3.7	22.7	-4.1	-.6	60.7	13.0	33.8	5.0	56.5	8.4
5-yr horizon (to 1992):					.0	9.2	.9	15.2		7.0	-.2		-8.5		-2.3		4.9		-10.8
10-yr horizon (to 1997):					.0	54.0	11.1	47.3		4.4	22.8		-20.1		23.0		23.7		-1.2
15-yr horizon (to 2002):					.0	107.7	32.3	47.4		-28.0	61.9		-13.5		94.3		46.0		62.0
20-yr horizon (to 2007):					.0	154.2	54.8	47.4		-51.9	82.7		-16.6		163.2		70.0		108.2
27-yr horizon (to 2014):					.0	202.0	81.5	47.4		-73.1	100.7		-19.8		244.3		99.1		156.9
30-yr horizon (to 2017):					.0	217.7	90.2	47.4		-80.0	106.5		-20.9		274.2		108.8		173.1
40-yr horizon (to 2027):					.0	255.2	111.1	47.4		-96.6	120.6		-23.5		356.8		132.7		213.0

All time horizons count 1987 as year 0. Beyond 2007 the benefit stream is assumed flat at the 2007 level.
Time horizon values of the raclr, teslr, voc.ch, cvl, and cv2 streams discounted at the utility discount rate.

Sensitivity 1

BASIC ASSUMPTIONS

number of hours of peak averaging:	150.00
utility discount rate (curr):	10.40
customer discount rate (curr):	8.00
societal discount rate (curr):	10.00
general inflation rate :	5.00
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	10.23
PGandE capacity cost (1987$/kW) :	129.00
rac customer cap. cost (1987$/kW) :	.00
tes customer cap. cost (1987$/kW) :	47.80
TES revenue loss factor (1987$/kW) :	89.00
sensitivity factor for pksavs.n :	1.20
sens. factor for modest deferrals :	1.27

1

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	.0	-1.9	.0	.0	.0	.0	.2	.0	.2	.2	-.0	.2	.2	.0	.0	.2	.2	.2	.2
1990	.0	-2.6	19.2	.0	.0	2.3	.2	2.9	.8	.6	-.0	-2.1	-1.5	1.2	.9	2.0	1.5	-.9	-.6
1991	.0	-3.7	38.5	-.0	.0	4.8	.4	3.0	-1.4	-.9	-.1	-4.5	-3.0	3.7	2.7	2.3	1.6	-.8	-.6
1992	.0	-5.1	58.1	.0	.0	7.0	.6	3.2	-3.2	-2.0	-.3	-6.7	-4.1	5.8	4.0	2.6	1.6	-.8	-.5
1993	.0	-7.1	77.8	.0	.0	9.8	.9	3.4	-5.5	-3.0	-.6	-9.5	-5.2	8.5	5.4	3.0	1.7	-1.0	-.6
1994	.0	-9.8	113.9	-.7	.0	14.8	1.4	6.6	-6.9	-3.4	-.5	-13.9	-7.0	12.4	7.2	5.5	2.8	-1.5	-.8
1995	.0	-13.7	150.0	-.6	.0	21.0	2.3	6.9	-11.8	-5.4	-.9	-19.6	-8.9	18.5	10.0	6.6	3.1	-1.1	-.5
1996	.0	-19.0	179.2	-.6	.0	26.2	9.5	5.8	-10.9	-4.5	31.2	14.5	6.0	24.0	12.0	13.2	5.6	38.6	16.4
1997	.0	-19.0	208.3	-.9	.0	31.6	10.7	6.1	-14.8	-5.5	30.2	9.3	3.5	29.3	13.6	14.6	5.6	38.7	14.9
1998	.0	-19.0	208.4	-.8	.0	33.2	12.2	.0	-21.0	-7.1	29.2	8.2	2.8	33.2	14.2	12.2	4.3	41.4	14.5
1999	.0	-19.0	208.7	-.9	.0	35.8	13.4	.1	-22.3	-6.8	28.6	6.2	1.9	35.7	14.2	13.4	4.3	42.0	13.4
2000	.0	-19.0	208.6	-.8	.0	38.7	14.9	-.0	-23.8	-6.6	27.8	4.0	1.1	38.7	14.2	14.9	4.3	42.7	12.4
2001	.0	-19.0	208.6	-.9	.0	42.1	17.5	.0	-24.6	-6.1	27.1	2.5	.6	42.1	14.3	17.5	4.6	44.6	11.7
2002	.0	-19.0	208.7	-.9	.0	45.7	20.2	.0	-25.5	-5.8	26.7	1.1	.3	45.7	14.4	20.2	4.8	46.9	11.2
2003	.0	-19.0	208.8	-.7	.0	49.9	21.6	.0	-28.3	-5.8	25.9	-2.4	-.5	49.9	14.6	21.6	4.7	47.5	10.3
2004	.0	-19.0	208.8	-.7	.0	52.4	23.6	.0	-28.8	-5.4	25.1	-3.7	-.7	52.4	14.2	23.6	4.7	48.7	9.6
2005	.0	-19.0	208.8	-.6	.0	55.0	26.6	.0	-28.4	-4.8	24.4	-4.0	-.7	55.0	13.8	26.6	4.8	51.0	9.2
2006	.0	-19.0	208.8	-.5	.0	57.8	29.6	.0	-28.2	-4.3	23.7	-4.4	-.7	57.8	13.4	29.6	4.8	53.3	8.7
2007	.0	-19.0	208.8	-.4	.0	60.7	33.8	.0	-26.9	-3.7	22.7	-4.1	-.6	60.7	13.0	33.8	5.0	56.5	8.4
5-yr horizon (to 1992):					.0	9.2	.9	6.1		-2.1	-.2		-8.5		7.6		4.9		-1.6
10-yr horizon (to 1997):					.0	54.0	11.1	19.1		-23.9	22.8		-20.1		55.8		23.7		27.8
15-yr horizon (to 2002):					.0	107.7	32.3	19.1		-56.2	61.9		-13.5		127.2		46.0		91.0
20-yr horizon (to 2007):					.0	154.2	54.8	19.1		-80.2	82.7		-16.6		196.1		70.1		137.3
27-yr horizon (to 2014):					.0	202.0	81.5	19.1		-101.4	100.7		-19.8		277.2		99.1		185.9
30-yr horizon (to 2017):					.0	217.7	90.2	19.1		-108.3	106.5		-20.9		307.1		108.9		202.2
40-yr horizon (to 2027):					.0	255.2	111.1	19.1		-125.0	120.6		-23.5		389.7		132.7		242.0

All time horizons count 1987 as year 0. Beyond 2007 the benefit stream is assumed flat at the 2007 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

Sensitivity 3

BASIC ASSUMPTIONS

number of hours of peak averaging:	150.00
utility discount rate (curr):	10.40
customer discount rate (curr):	8.00
societal discount rate (curr):	10.00
general inflation rate :	5.00
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	10.23
PGandE capacity cost (1987$/kW) :	129.00
rac customer cap. cost (1987$/kW) :	.00
tes customer cap. cost (1987$/kW) :	47.80
TES revenue loss factor (1987$/kW) :	45.00
sensitivity factor for pksavs.n :	1.20
sens. factor for modest deferrals :	1.27

1

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	.0	-1.9	.0	.0	.0	.0	.2	.0	.2	.2	-.0	.2	.2	.0	.0	.2	.2	.2	.2
1990	.0	-2.6	19.2	.0	.0	1.1	.2	2.9	1.9	1.4	-.0	-.9	-.7	.1	.1	2.0	1.5	-.9	-.6
1991	.0	-3.7	38.5	-.0	.0	2.4	.4	3.0	1.0	.7	-.1	-2.2	-1.4	1.3	1.0	2.3	1.6	-.8	-.6
1992	.0	-5.1	58.1	.0	.0	3.6	.6	3.2	.3	.2	-.3	-3.2	-2.0	2.4	1.6	2.6	1.6	-.8	-.5
1993	.0	-7.1	77.8	.0	.0	4.9	.9	3.4	-.6	-.4	-.6	-4.7	-2.6	3.7	2.3	3.0	1.7	-1.0	-.6
1994	.0	-9.8	113.9	-.7	.0	7.5	1.4	6.6	.5	.2	-.5	-6.6	-3.3	5.1	3.0	5.5	2.8	-1.5	-.8
1995	.0	-13.7	150.0	-.6	.0	10.6	2.3	6.9	-1.4	-.7	-.9	-9.2	-4.2	8.1	4.4	6.6	3.1	-1.1	-.5
1996	.0	-19.0	179.2	-.6	.0	13.2	9.5	5.8	2.1	.9	31.2	27.5	11.3	11.1	5.5	13.2	5.6	38.6	16.4
1997	.0	-19.0	208.3	-.9	.0	16.0	10.7	6.1	.9	.3	30.2	25.0	9.3	13.7	6.3	14.6	5.6	38.7	14.9
1998	.0	-19.0	208.4	-.8	.0	16.8	12.2	.0	-4.6	-1.5	29.2	24.6	8.3	16.8	7.2	12.2	4.3	41.4	14.5
1999	.0	-19.0	208.7	-.9	.0	18.1	13.4	.1	-4.6	-1.4	28.6	23.9	7.3	18.1	7.2	13.4	4.3	42.0	13.4
2000	.0	-19.0	208.6	-.8	.0	19.6	14.9	-.0	-4.7	-1.3	27.8	23.2	6.4	19.6	7.2	14.9	4.3	42.7	12.4
2001	.0	-19.0	208.6	-.9	.0	21.3	17.5	.0	-3.8	-.9	27.1	23.3	5.8	21.3	7.2	17.5	4.6	44.6	11.7
2002	.0	-19.0	208.7	-.9	.0	23.1	20.2	.0	-2.9	-.7	26.7	23.8	5.4	23.1	7.3	20.2	4.8	46.9	11.2
2003	.0	-19.0	208.8	-.7	.0	25.2	21.6	.0	-3.6	-.7	25.9	22.3	4.6	25.2	7.4	21.6	4.7	47.5	10.3
2004	.0	-19.0	208.8	-.7	.0	26.5	23.6	.0	-2.9	-.5	25.1	22.3	4.1	26.5	7.2	23.6	4.7	48.7	9.6
2005	.0	-19.0	208.8	-.6	.0	27.8	26.6	.0	-1.2	-.2	24.4	23.2	3.9	27.8	7.0	26.6	4.8	51.0	9.2
2006	.0	-19.0	208.8	-.5	.0	29.2	29.6	.0	.4	.1	23.7	24.1	3.7	29.2	6.8	29.6	4.8	53.3	8.7
2007	.0	-19.0	208.8	-.4	.0	30.7	33.8	.0	3.1	.4	22.7	25.9	3.6	30.7	6.6	33.8	5.0	56.5	8.4
5-yr horizon (to 1992):					.0	4.6	.9	6.1		2.4	-.2		-3.9		2.6		4.9		-1.6
10-yr horizon (to 1997):					.0	27.3	11.1	19.1		2.8	22.8		6.6		24.2		23.7		27.8
15-yr horizon (to 2002):					.0	54.5	32.3	19.1		-3.0	61.9		39.8		60.2		46.0		91.0
20-yr horizon (to 2007):					.0	77.9	54.8	19.1		-4.0	82.7		59.6		95.1		70.1		137.3
27-yr horizon (to 2014):					.0	102.1	81.5	19.1		-1.5	100.7		80.0		136.1		99.1		185.9
30-yr horizon (to 2017):					.0	110.1	90.2	19.1		-.7	106.5		86.7		151.2		108.9		202.2
40-yr horizon (to 2027):					.0	129.0	111.1	19.1		1.2	120.6		102.7		193.0		132.7		242.0

All time horizons count 1987 as year 0. Beyond 2007 the benefit stream is assumed flat at the 2007 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

C-5

Sensitivity 4

BASIC ASSUMPTIONS

number of hours of peak averaging:	15Ø.ØØ
utility discount rate (curr):	1Ø.ØØ
customer discount rate (curr):	1Ø.ØØ
societal discount rate (curr):	1Ø.ØØ
general inflation rate :	5.ØØ
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	1Ø.23
PGandE capacity cost (1987$/kW) :	32Ø.ØØ
rac customer cap. cost (1987$/kW) :	.ØØ
tes customer cap. cost (1987$/kW) :	975.ØØ
TES revenue loss factor (1987$/kW) :	89.ØØ
sensitivity factor for pksavs.n :	1.2Ø
sens. factor for modest deferrals :	1.27

1

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	.Ø	-1.9	.Ø	.Ø	.Ø	.Ø	.2	.Ø	.2	.2	-.Ø	.2	.2	.Ø	.Ø	.2	.2	.2	.2
199Ø	.Ø	-2.6	19.2	.Ø	.Ø	2.3	.2	7.1	5.1	3.8	-.Ø	-2.1	-1.5	-19.4	-14.6	-14.4	-1Ø.8	-21.5	-16.1
1991	.Ø	-3.7	38.5	-.Ø	.Ø	4.8	.4	7.5	3.1	2.1	-.1	-4.5	-3.1	-18.1	-12.4	-15.Ø	-1Ø.2	-22.6	-15.5
1992	.Ø	-5.1	58.1	.Ø	.Ø	7.Ø	.6	8.Ø	1.6	1.Ø	-.3	-6.7	-4.2	-17.3	-1Ø.7	-15.8	-9.8	-24.Ø	-14.9
1993	.Ø	-7.1	77.8	.Ø	.Ø	9.8	.9	8.4	-.4	-.2	-.6	-9.5	-5.4	-16.Ø	-9.Ø	-16.4	-9.2	-25.4	-14.4
1994	.Ø	-9.8	113.9	-.7	.Ø	14.8	1.4	16.3	2.8	1.5	-.5	-13.9	-7.1	-34.7	-17.8	-31.9	-16.4	-48.7	-25.Ø
1995	.Ø	-13.7	15Ø.Ø	-.6	.Ø	21.Ø	2.3	17.1	-1.6	-.8	-.9	-19.6	-9.1	-31.Ø	-14.5	-32.7	-15.2	-5Ø.6	-23.6
1996	.Ø	-19.Ø	179.2	-.6	.Ø	26.2	9.5	14.5	-2.2	-.9	31.2	14.5	6.2	-17.9	-7.6	-2Ø.1	-8.5	-3.4	-1.4
1997	.Ø	-19.Ø	2Ø8.3	-.9	.Ø	31.6	1Ø.7	15.2	-5.7	-2.2	3Ø.2	9.3	3.6	-14.7	-5.7	-2Ø.4	-7.9	-5.4	-2.1
1998	.Ø	-19.Ø	2Ø8.4	-.8	.Ø	33.2	12.2	.1	-2Ø.9	-7.3	29.2	8.2	2.9	33.Ø	11.6	12.1	4.2	41.2	14.4
1999	.Ø	-19.Ø	2Ø8.7	-.9	.Ø	35.8	13.4	.1	-22.2	-7.1	28.6	6.2	2.Ø	35.3	11.3	13.1	4.2	41.6	13.2
2ØØØ	.Ø	-19.Ø	2Ø8.6	-.8	.Ø	38.7	14.9	-.1	-23.9	-6.9	27.8	4.Ø	1.2	38.9	11.3	15.Ø	4.4	42.9	12.4
2ØØ1	.Ø	-19.Ø	2Ø8.6	-.9	.Ø	42.1	17.5	.Ø	-24.6	-6.5	27.1	2.5	.7	42.1	11.1	17.5	4.6	44.6	11.7
2ØØ2	.Ø	-19.Ø	2Ø8.7	-.9	.Ø	45.7	2Ø.2	.1	-25.4	-6.1	26.7	1.1	.3	45.5	1Ø.9	2Ø.Ø	4.8	46.6	11.2
2ØØ3	.Ø	-19.Ø	2Ø8.8	-.7	.Ø	49.9	21.6	.1	-28.2	-6.1	25.9	-2.4	-.5	49.6	1Ø.8	21.4	4.7	47.3	1Ø.3
2ØØ4	.Ø	-19.Ø	2Ø8.8	-.7	.Ø	52.4	23.6	.Ø	-28.8	-5.7	25.1	-3.7	-.7	52.4	1Ø.4	23.6	4.7	48.7	9.6
2ØØ5	.Ø	-19.Ø	2Ø8.8	-.6	.Ø	55.Ø	26.6	.Ø	-28.4	-5.1	24.4	-4.Ø	-.7	55.Ø	9.9	26.6	4.8	51.Ø	9.2
2ØØ6	.Ø	-19.Ø	2Ø8.8	-.5	.Ø	57.8	29.6	.Ø	-28.2	-4.6	23.7	-4.4	-.7	57.8	9.4	29.6	4.8	53.3	8.7
2ØØ7	.Ø	-19.Ø	2Ø8.8	-.4	.Ø	6Ø.7	33.8	.Ø	-26.9	-4.Ø	22.7	-4.1	-.6	6Ø.7	9.Ø	33.8	5.Ø	56.5	8.4
5-yr horizon (to 1992):					.Ø	9.3	1.Ø	15.4		7.1	-.2		-8.6		-37.7		-3Ø.6		-46.3
1Ø-yr horizon (to 1997):					.Ø	55.6	11.4	48.5		4.4	23.6		-2Ø.5		-92.3		-87.9		-112.8
15-yr horizon (to 2ØØ2):					.Ø	111.8	33.7	48.6		-29.5	64.5		-13.6		-36.2		-65.7		-49.8
2Ø-yr horizon (to 2ØØ7):					.Ø	161.4	57.7	48.6		-55.1	86.8		-16.9		13.3		-41.7		-3.5
27-yr horizon (to 2Ø14):					.Ø	213.6	86.8	48.6		-78.2	1Ø6.3		-2Ø.4		65.5		-12.7		45.1
3Ø-yr horizon (to 2Ø17):					.Ø	231.Ø	96.5	48.6		-85.9	112.9		-21.6		83.Ø		-2.9		61.4
4Ø-yr horizon (to 2Ø27):					.Ø	273.8	12Ø.4	48.6		-1Ø4.8	128.9		-24.5		125.7		2Ø.9		1Ø1.2

All time horizons count 1987 as year Ø. Beyond 2ØØ7 the benefit stream is assumed flat at the 2ØØ7 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

BASIC ASSUMPTIONS

number of hours of peak averaging:	15Ø.ØØ
utility discount rate (curr):	1Ø.ØØ
customer discount rate (curr):	1Ø.ØØ
societal discount rate (curr):	1Ø.ØØ
general inflation rate :	5.ØØ
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	1Ø.23
PGandE capacity cost (1987$/kW) :	725.ØØ
rac customer cap. cost (1987$/kW) :	.ØØ
tes customer cap. cost (1987$/kW) :	136Ø.ØØ
TES revenue loss factor (1987$/kW) :	89.ØØ
sensitivity factor for pksavs.n :	1.2Ø
sens. factor for modest deferrals :	1.27

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FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	.Ø	-1.9	.Ø	.Ø	.Ø	.Ø	.2	.Ø	.2	.2	-.Ø	.2	.2	.Ø	.Ø	.2	.2	.2	.2
199Ø	.Ø	-2.6	19.2	.Ø	.Ø	2.3	.2	16.1	14.1	1Ø.6	-.Ø	-2.1	-1.5	-28.Ø	-21.Ø	-13.9	-1Ø.5	-3Ø.Ø	-22.6
1991	.Ø	-3.7	38.5	-.Ø	.Ø	4.8	.4	17.Ø	12.6	8.6	-.1	-4.5	-3.1	-27.1	-18.5	-14.5	-9.9	-31.7	-21.6
1992	.Ø	-5.1	58.1	.Ø	.Ø	7.Ø	.6	18.1	11.7	7.2	-.3	-6.7	-4.2	-26.9	-16.7	-15.3	-9.5	-33.6	-2Ø.9
1993	.Ø	-7.1	77.8	.Ø	.Ø	9.8	.9	19.1	1Ø.3	5.8	-.6	-9.5	-5.4	-26.1	-14.7	-15.8	-8.9	-35.6	-2Ø.1
1994	.Ø	-9.8	113.9	-.7	.Ø	14.8	1.4	36.8	23.4	12.Ø	-.5	-13.9	-7.1	-54.3	-27.9	-3Ø.9	-15.8	-68.2	-35.Ø
1995	.Ø	-13.7	15Ø.Ø	-.6	.Ø	21.Ø	2.3	38.7	2Ø.Ø	9.3	-.9	-19.6	-9.1	-51.6	-24.1	-31.6	-14.7	-71.2	-33.2
1996	.Ø	-19.Ø	179.2	-.6	.Ø	26.2	9.5	32.8	16.1	6.8	31.2	14.5	6.2	-35.3	-15.Ø	-19.2	-8.2	-2Ø.8	-8.8
1997	.Ø	-19.Ø	2Ø8.3	-.9	.Ø	31.6	1Ø.7	34.4	13.5	5.2	3Ø.2	9.3	3.6	-33.Ø	-12.7	-19.5	-7.5	-23.7	-9.1
1998	.Ø	-19.Ø	2Ø8.4	-.8	.Ø	33.2	12.2	.1	-2Ø.8	-7.3	29.2	8.2	2.9	32.9	11.5	12.1	4.2	41.1	14.4
1999	.Ø	-19.Ø	2Ø8.7	-.9	.Ø	35.8	13.4	.3	-22.1	-7.Ø	28.6	6.2	2.Ø	35.2	11.2	13.1	4.2	41.4	13.2
2ØØØ	.Ø	-19.Ø	2Ø8.6	-.8	.Ø	38.7	14.9	-.2	-23.9	-6.9	27.8	4.Ø	1.2	39.Ø	11.3	15.Ø	4.4	43.Ø	12.5
2ØØ1	.Ø	-19.Ø	2Ø8.6	-.9	.Ø	42.1	17.5	.Ø	-24.6	-6.5	27.1	2.5	.7	42.1	11.1	17.5	4.6	44.6	11.7
2ØØ2	.Ø	-19.Ø	2Ø8.7	-.9	.Ø	45.7	2Ø.2	.2	-25.3	-6.1	26.7	1.1	.3	45.4	1Ø.9	2Ø.Ø	4.8	46.5	11.1
2ØØ3	.Ø	-19.Ø	2Ø8.8	-.7	.Ø	49.9	21.6	.2	-28.1	-6.1	25.9	-2.4	-.5	49.5	1Ø.8	21.4	4.7	47.2	1Ø.3
2ØØ4	.Ø	-19.Ø	2Ø8.8	-.7	.Ø	52.4	23.6	.Ø	-28.8	-5.7	25.1	-3.7	-.7	52.4	1Ø.4	23.6	4.7	48.7	9.6
2ØØ5	.Ø	-19.Ø	2Ø8.8	-.6	.Ø	55.Ø	26.6	.Ø	-28.4	-5.1	24.4	-4.Ø	-.7	55.Ø	9.9	26.6	4.8	51.Ø	9.2
2ØØ6	.Ø	-19.Ø	2Ø8.8	-.5	.Ø	57.8	29.6	.Ø	-28.2	-4.6	23.7	-4.4	-.7	57.8	9.4	29.6	4.8	53.3	8.7
2ØØ7	.Ø	-19.Ø	2Ø8.8	-.4	.Ø	6Ø.7	33.8	.Ø	-26.9	-4.Ø	22.7	-4.1	-.6	6Ø.7	9.Ø	33.8	5.Ø	56.5	8.4
5-yr horizon (to 1992):					.Ø	9.3	1.Ø	35.Ø		26.6	-.2		-8.6		-56.3		-29.7		-64.9
1Ø-yr horizon (to 1997):					.Ø	55.6	11.4	1Ø9.9		65.8	23.6		-2Ø.5		-15Ø.6		-84.9		-171.1
15-yr horizon (to 2ØØ2):					.Ø	111.8	33.7	11Ø.1		32.Ø	64.5		-13.6		-94.6		-62.7		-1Ø8.2
2Ø-yr horizon (to 2ØØ7):					.Ø	161.4	57.7	11Ø.1		6.4	86.8		-16.9		-45.1		-38.7		-62.Ø
27-yr horizon (to 2Ø14):					.Ø	213.6	86.8	11Ø.1		-16.7	1Ø6.3		-2Ø.4		7.Ø		-9.6		-13.4
3Ø-yr horizon (to 2Ø17):					.Ø	231.Ø	96.5	11Ø.1		-24.4	112.9		-21.6		24.5		.1		2.9
4Ø-yr horizon (to 2Ø27):					.Ø	273.8	12Ø.4	11Ø.1		-43.3	128.9		-24.5		67.2		23.9		42.7

All time horizons count 1987 as year Ø. Beyond 2ØØ7 the benefit stream is assumed flat at the 2ØØ7 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

BASIC ASSUMPTIONS

number of hours of peak averaging:	15Ø.ØØ
utility discount rate (curr):	1Ø.4Ø
customer discount rate (curr):	8.ØØ
societal discount rate (curr):	1Ø.ØØ
general inflation rate :	5.ØØ
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	1Ø.23
PGandE capacity cost (1987$/kW) :	725.ØØ
rac customer cap. cost (1987$/kW) :	.ØØ
tes customer cap. cost (1987$/kW) :	136Ø.ØØ
TES revenue loss factor (1987$/kW) :	81.ØØ
sensitivity factor for pksavs.n :	1.2Ø
sens. factor for modest deferrals :	1.27

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FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	.Ø	-1.9	.Ø	.Ø	.Ø	.Ø	.2	.Ø	.2	.2	-.Ø	.2	.2	.Ø	.Ø	.2	.2	.2	.2
199Ø	.Ø	-2.6	19.2	.Ø	.Ø	2.Ø	.2	16.1	14.3	1Ø.6	-.Ø	-1.8	-1.4	-28.2	-22.4	-13.9	-1Ø.5	-3Ø.Ø	-22.6
1991	.Ø	-3.7	38.5	-.Ø	.Ø	4.4	.4	17.Ø	13.1	8.8	-.1	-4.1	-2.8	-27.6	-2Ø.3	-14.5	-9.9	-31.7	-21.6
1992	.Ø	-5.1	58.1	.Ø	.Ø	6.4	.6	18.1	12.3	7.5	-.3	-6.1	-3.7	-27.6	-18.8	-15.3	-9.5	-33.6	-2Ø.9
1993	.Ø	-7.1	77.8	.Ø	.Ø	8.9	.9	19.1	11.1	6.2	-.6	-8.6	-4.8	-27.Ø	-17.Ø	-15.8	-8.9	-35.6	-2Ø.1
1994	.Ø	-9.8	113.9	-.7	.Ø	13.5	1.4	36.8	24.8	12.4	-.5	-12.6	-6.3	-55.6	-32.5	-3Ø.9	-15.8	-68.2	-35.Ø
1995	.Ø	-13.7	15Ø.Ø	-.6	.Ø	19.1	2.3	38.7	21.9	9.9	-.9	-17.7	-8.Ø	-53.4	-28.9	-31.6	-14.7	-71.2	-33.2
1996	.Ø	-19.Ø	179.2	-.6	.Ø	23.8	9.5	32.8	18.5	7.6	31.2	16.9	6.9	-37.7	-18.8	-19.2	-8.2	-2Ø.8	-8.8
1997	.Ø	-19.Ø	2Ø8.3	-.9	.Ø	28.8	1Ø.7	34.4	16.4	6.1	3Ø.2	12.2	4.5	-35.8	-16.6	-19.5	-7.5	-23.7	-9.1
1998	.Ø	-19.Ø	2Ø8.4	-.8	.Ø	3Ø.2	12.2	.1	-17.9	-6.Ø	29.2	11.2	3.8	29.9	12.8	12.1	4.2	41.1	14.4
1999	.Ø	-19.Ø	2Ø8.7	-.9	.Ø	32.6	13.4	.3	-18.8	-5.7	28.6	9.4	2.9	32.Ø	12.7	13.1	4.2	41.4	13.2
2ØØØ	.Ø	-19.Ø	2Ø8.6	-.8	.Ø	35.2	14.9	-.2	-2Ø.5	-5.7	27.8	7.5	2.1	35.5	13.1	15.Ø	4.4	43.Ø	12.5
2ØØ1	.Ø	-19.Ø	2Ø8.6	-.9	.Ø	38.3	17.5	.Ø	-2Ø.8	-5.2	27.1	6.3	1.6	38.3	13.Ø	17.5	4.6	44.6	11.7
2ØØ2	.Ø	-19.Ø	2Ø8.7	-.9	.Ø	41.6	2Ø.2	.2	-21.2	-4.8	26.7	5.3	1.2	41.3	13.Ø	2Ø.Ø	4.8	46.5	11.1
2ØØ3	.Ø	-19.Ø	2Ø8.8	-.7	.Ø	45.4	21.6	.2	-23.6	-4.9	25.9	2.1	.4	45.1	13.2	21.4	4.7	47.2	1Ø.3
2ØØ4	.Ø	-19.Ø	2Ø8.8	-.7	.Ø	47.7	23.6	.Ø	-24.1	-4.5	25.1	1.1	.2	47.7	12.9	23.6	4.7	48.7	9.6
2ØØ5	.Ø	-19.Ø	2Ø8.8	-.6	.Ø	5Ø.1	26.6	.Ø	-23.5	-4.Ø	24.4	.9	.2	5Ø.1	12.5	26.6	4.8	51.Ø	9.2
2ØØ6	.Ø	-19.Ø	2Ø8.8	-.5	.Ø	52.6	29.6	.Ø	-23.Ø	-3.5	23.7	.8	.1	52.6	12.2	29.6	4.8	53.3	8.7
2ØØ7	.Ø	-19.Ø	2Ø8.8	-.4	.Ø	55.2	33.8	.Ø	-21.4	-3.Ø	22.7	1.3	.2	55.2	11.8	33.8	5.Ø	56.5	8.4
5-yr horizon (to 1992):					.Ø	8.4	.9	34.5		27.1	-.2		-7.7		-61.4		-29.7		-64.9
1Ø-yr horizon (to 1997):					.Ø	49.2	11.1	1Ø7.3		69.2	22.8		-15.3		-175.2		-84.9		-171.1
15-yr horizon (to 2ØØ2):					.Ø	98.Ø	32.3	1Ø7.4		41.7	61.9		-3.8		-11Ø.5		-62.7		-1Ø8.2
2Ø-yr horizon (to 2ØØ7):					.Ø	14Ø.3	54.8	1Ø7.4		22.Ø	82.7		-2.7		-47.9		-38.7		-62.Ø
27-yr horizon (to 2Ø14):					.Ø	183.8	81.5	1Ø7.4		5.1	1ØØ.7		-1.7		25.9		-9.6		-13.4
3Ø-yr horizon (to 2Ø17):					.Ø	198.1	9Ø.2	1Ø7.4		-.4	1Ø6.5		-1.3		53.1		.1		2.9
4Ø-yr horizon (to 2Ø27):					.Ø	232.3	111.1	1Ø7.4		-13.7	12Ø.6		-.5		128.3		23.9		42.7

All time horizons count 1987 as year Ø. Beyond 2ØØ7 the benefit stream is assumed flat at the 2ØØ7 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

Appendix D

EVALER Sensitivities for RAC Case

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	7.3	.0	.0	7.4	.9	.0	.2	.0	-.7	-.6	-.0	-.7	-.6	-13.0	-10.7	-13.7	-11.3	-13.7	-11.3
1990	11.4	.0	11.0	8.1	1.5	.0	1.2	4.1	3.8	2.8	.8	.4	.3	-13.3	-10.0	-9.6	-7.2	-12.9	-9.7
1991	17.7	.0	22.2	7.7	2.5	.0	1.5	4.3	3.3	2.3	.8	-.3	-.2	-14.0	-9.6	-10.7	-7.3	-14.3	-9.8
1992	27.7	.0	38.6	7.7	3.9	.0	2.0	6.7	4.9	3.0	.7	-1.2	-.7	-14.7	-9.1	-9.8	-6.1	-15.9	-9.9
1993	43.2	.0	55.2	7.7	6.2	.0	2.7	7.1	3.6	2.0	6.5	3.0	1.7	-40.3	-22.7	-36.7	-20.7	-37.3	-21.1
1994	67.4	.0	83.6	7.1	10.1	.0	3.9	12.8	6.6	3.4	6.4	.2	.1	-41.8	-21.4	-35.2	-18.0	-41.6	-21.3
1995	87.6	.0	112.1	7.1	14.1	.0	5.1	13.4	4.4	2.1	6.0	-3.0	-1.4	-43.5	-20.3	-39.0	-18.2	-46.4	-21.7
1996	113.8	.0	150.6	7.3	19.1	.0	12.7	19.1	12.7	5.4	27.3	20.9	8.8	-45.1	-19.1	-32.4	-13.7	-24.2	-10.3
1997	148.0	.0	189.2	7.6	25.8	.0	16.3	20.1	10.6	4.1	26.2	16.7	6.4	-45.6	-17.6	-34.9	-13.5	-28.9	-11.1
1998	192.4	.0	225.1	7.6	35.2	.0	20.9	19.6	5.3	1.9	25.5	11.2	3.9	-43.3	-15.2	-37.9	-13.3	-32.1	-11.2
1999	203.9	.0	260.9	7.6	40.2	.0	24.1	20.6	4.5	1.4	24.7	8.7	2.8	-45.3	-14.4	-40.8	-13.0	-36.6	-11.7
2000	216.2	.0	277.0	7.6	46.1	.0	27.4	9.7	-9.0	-2.6	24.2	5.5	1.6	-46.5	-13.5	-55.5	-16.1	-41.0	-11.9
2001	229.1	.0	293.2	7.6	53.1	.0	32.4	10.3	-10.5	-2.8	23.4	2.7	.7	-46.1	-12.1	-56.6	-14.9	-43.4	-11.4
2002	242.9	.0	311.2	7.6	61.2	.0	37.9	12.0	-11.3	-2.7	23.0	-.3	-.1	-45.7	-10.9	-57.0	-13.6	-46.0	-11.0
2003	257.5	.0	329.3	7.6	70.7	.0	52.1	12.7	-6.0	-1.3	51.0	32.4	7.1	-44.0	-9.6	-50.0	-10.9	-11.6	-2.5
2004	257.5	.0	329.3	7.6	74.3	.0	57.1	.0	-17.2	-3.4	49.2	32.0	6.3	74.3	14.7	57.1	11.3	106.3	21.0
2005	257.5	.0	329.3	7.6	78.0	.0	62.3	.0	-15.7	-2.8	47.9	32.2	5.8	78.0	14.0	62.3	11.2	110.2	19.8
2006	257.5	.0	329.3	7.7	81.9	.0	69.0	.0	-12.9	-2.1	46.8	33.9	5.5	81.9	13.4	69.0	11.3	115.8	18.9
2007	257.5	.0	329.3	7.7	86.0	.0	78.2	.0	-7.8	-1.2	45.5	37.8	5.6	86.0	12.8	78.2	11.6	123.7	18.4
5-yr horizon (to 1992):					6.0	.0	3.3	10.2		7.5	1.5		-1.2		-39.4		-31.9		-40.6
10-yr horizon (to 1997):					39.4	.0	20.9	42.9		24.5	32.9		14.5		-140.6		-116.1		-126.1
15-yr horizon (to 2002):					106.5	.0	61.5	64.7		19.7	68.5		23.4		-206.7		-187.0		-183.3
20-yr horizon (to 2007):					176.8	.0	118.2	67.5		8.9	112.3		53.7		-161.4		-152.5		-107.7
27-yr horizon (to 2014):					250.7	.0	185.5	67.5		2.2	151.5		86.2		-87.4		-85.2		-1.2
30-yr horizon (to 2017):					275.5	.0	208.0	67.5		-.0	164.6		97.0		-62.7		-62.7		34.4
40-yr horizon (to 2027):					336.1	.0	263.1	67.5		-5.5	196.7		123.7		-2.1		-7.6		121.5

All time horizons count 1987 as year 0. Beyond 2007 the benefit stream is assumed flat at the 2007 level.
Time horizon values of the raclr, teslr, voc.ch, cvl, and cv2 streams discounted at the utility discount rate.

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BASE : #115; BASE CASE WITH BOTH TES AND RAC CAPABILITY 7/15/87

***** compared to *******

POLICY : #127; POLICY CASE WITH RAC ON AND S-SIDE DEFERRALS 17JUL87

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BASIC ASSUMPTIONS

number of hours of peak averaging	:	150.00
utility discount rate (curr)	:	10.00
customer discount rate (curr)	:	10.00
societal discount rate (curr)	:	10.00
general inflation rate	:	5.00
retail price index for 1987	:	1.52
1987 tier2 price (c/kWh)	:	10.23
PGandE capacity cost (1987$/kW)	:	320.00
rac customer cap. cost (1987$/kW)	:	.00
tes customer cap. cost (1987$/kW)	:	.00
TES revenue loss factor (1987$/kW)	:	.00
sensitivity factor for pksavs.n	:	1.20
sens. factor for modest deferrals	:	1.10

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	7.3	.0	.0	7.4	.9	.0	.2	.0	-.7	-.6	-.0	-.7	-.6	-22.9	-18.9	-23.6	-19.5	-23.6	-19.5
1990	11.4	.0	11.0	8.1	1.5	.0	1.2	4.1	3.8	2.8	.8	.4	.3	-23.8	-17.9	-20.1	-15.1	-23.4	-17.6
1991	17.7	.0	22.2	7.7	2.5	.0	1.5	4.3	3.3	2.3	.8	-.3	-.2	-25.8	-17.6	-22.5	-15.3	-26.0	-17.8
1992	27.7	.0	38.6	7.7	3.9	.0	2.0	6.7	4.9	3.0	.7	-1.2	-.7	-27.8	-17.3	-23.0	-14.3	-29.0	-18.0
1993	43.2	.0	55.2	7.7	6.2	.0	2.7	7.1	3.6	2.0	6.5	3.0	1.7	-73.3	-41.4	-69.7	-39.4	-70.3	-39.7
1994	67.4	.0	83.6	7.1	10.1	.0	3.9	12.8	6.6	3.4	6.4	.2	.1	-78.6	-40.3	-72.0	-36.9	-78.4	-40.2
1995	87.6	.0	112.1	7.1	14.1	.0	5.1	13.4	4.4	2.1	6.0	-3.0	-1.4	-84.3	-39.3	-79.9	-37.3	-87.3	-40.7
1996	113.8	.0	150.6	7.3	19.1	.0	12.7	19.1	12.7	5.4	27.3	20.9	8.8	-90.6	-38.4	-77.9	-33.0	-69.8	-29.6
1997	148.0	.0	189.2	7.6	25.8	.0	16.3	20.1	10.6	4.1	26.2	16.7	6.4	-96.2	-37.1	-85.5	-33.0	-79.5	-30.6
1998	192.4	.0	225.1	7.6	35.2	.0	20.9	19.6	5.3	1.9	25.5	11.2	3.9	-98.9	-34.7	-93.6	-32.8	-87.7	-30.7
1999	203.9	.0	260.9	7.6	40.2	.0	24.1	20.6	4.5	1.4	24.7	8.7	2.8	-105.9	-33.7	-101.4	-32.3	-97.2	-31.0
2000	216.2	.0	277.0	7.6	46.1	.0	27.4	9.7	-9.0	-2.6	24.2	5.5	1.6	-112.2	-32.5	-121.1	-35.1	-106.6	-30.9
2001	229.1	.0	293.2	7.6	53.1	.0	32.4	10.3	-10.5	-2.8	23.4	2.7	.7	-116.5	-30.7	-126.9	-33.4	-113.8	-30.0
2002	242.9	.0	311.2	7.6	61.2	.0	37.9	12.0	-11.3	-2.7	23.0	-.3	-.1	-121.5	-29.1	-132.8	-31.8	-121.8	-29.2
2003	257.5	.0	329.3	7.6	70.7	.0	52.1	12.7	-6.0	-1.3	51.0	32.4	7.1	-125.4	-27.3	-131.4	-28.6	-93.1	-20.3
2004	257.5	.0	329.3	7.6	74.3	.0	57.1	.0	-17.2	-3.4	49.2	32.0	6.3	74.3	14.7	57.1	11.3	106.3	21.[illegible]
2005	257.5	.0	329.3	7.6	78.0	.0	62.3	.0	-15.7	-2.8	47.9	32.2	5.8	78.0	14.0	62.3	11.2	110.2	19.[illegible]
2006	257.5	.0	329.3	7.7	81.9	.0	69.0	.0	-12.9	-2.1	46.8	33.9	5.5	81.9	13.4	69.0	11.3	115.8	18.9
2007	257.5	.0	329.3	7.7	86.0	.0	78.2	.0	-7.8	-1.2	45.5	37.8	5.6	86.0	12.8	78.2	11.6	123.7	18.4
5-yr horizon (to 1992):					6.0	.0	3.3	10.2		7.5	1.5		-1.2		-71.7		-64.2		-72.9
10-yr horizon (to 1997):					39.4	.0	20.9	42.9		24.5	32.9		14.5		-268.2		-243.8		-253.7
15-yr horizon (to 2002):					106.5	.0	61.5	64.7		19.7	68.5		23.4		-428.9		-409.2		-405.5
20-yr horizon (to 2007):					176.8	.0	118.2	67.5		8.9	112.3		53.7		-401.3		-392.4		-347.6
27-yr horizon (to 2014):					250.7	.0	185.5	67.5		2.2	151.5		86.2		-327.3		-325.1		-241.2
30-yr horizon (to 2017):					275.5	.0	208.0	67.5		-.0	164.6		97.0		-302.6		-302.6		-205.6
40-yr horizon (to 2027):					336.1	.0	263.1	67.5		-5.5	196.7		123.7		-242.0		-247.5		-118.4

All time horizons count 1987 as year 0. Beyond 2007 the benefit stream is assumed flat at the 2007 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

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BASE : #115; BASE CASE WITH BOTH TES AND RAC CAPABILITY 7/15/87

***** compared to *******

POLICY : #127; POLICY CASE WITH RAC ON AND S-SIDE DEFERRALS 17JUL87

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HIGH CUSTOMER COSTS IN EFFECT

BASIC ASSUMPTIONS

number of hours of peak averaging:	150.00
utility discount rate (curr):	10.00
customer discount rate (curr):	10.00
societal discount rate (curr):	10.00
general inflation rate :	5.00
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	10.23
PGandE capacity cost (1987$/kW) :	320.00
rac customer cap. cost (1987$/kW) :	.00
tes customer cap. cost (1987$/kW) :	.00
TES revenue loss factor (1987$/kW) :	.00
sensitivity factor for pksavs.n :	1.20
sens. factor for modest deferrals :	1.10

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	7.3	.0	.0	7.4	.9	.0	.2	.0	-.7	-.6	-.0	-.7	-.6	-13.0	-10.7	-13.7	-11.3	-13.7	-11.3
1990	11.4	.0	11.0	8.1	1.5	.0	1.2	9.3	8.9	6.7	.8	.4	.3	-13.3	-10.0	-4.4	-3.3	-12.9	-9.7
1991	17.7	.0	22.2	7.7	2.5	.0	1.5	9.8	8.8	6.0	.8	-.3	-.2	-14.0	-9.6	-5.2	-3.6	-14.3	-9.8
1992	27.7	.0	38.6	7.7	3.9	.0	2.0	15.2	13.4	8.3	.7	-1.2	-.7	-14.7	-9.1	-1.3	-.8	-15.9	-9.9
1993	43.2	.0	55.2	7.7	6.2	.0	2.7	16.1	12.6	7.1	6.5	3.0	1.7	-40.3	-22.7	-27.7	-15.7	-37.3	-21.1
1994	67.4	.0	83.6	7.1	10.1	.0	3.9	29.0	22.8	11.7	6.4	.2	.1	-41.8	-21.4	-19.0	-9.7	-41.6	-21.3
1995	87.6	.0	112.1	7.1	14.1	.0	5.1	30.5	21.5	10.0	6.0	-3.0	-1.4	-43.5	-20.3	-22.0	-10.3	-46.4	-21.7
1996	113.8	.0	150.6	7.3	19.1	.0	12.7	43.3	36.9	15.6	27.3	20.9	8.8	-45.1	-19.1	-8.2	-3.5	-24.2	-10.3
1997	148.0	.0	189.2	7.6	25.8	.0	16.3	45.6	36.1	13.9	26.2	16.7	6.4	-45.6	-17.6	-9.4	-3.6	-28.9	-11.1
1998	192.4	.0	225.1	7.6	35.2	.0	20.9	44.5	30.2	10.6	25.5	11.2	3.9	-43.3	-15.2	-13.1	-4.6	-32.1	-11.2
1999	203.9	.0	260.9	7.6	40.2	.0	24.1	46.6	30.5	9.7	24.7	8.7	2.8	-45.3	-14.4	-14.8	-4.7	-36.6	-11.7
2000	216.2	.0	277.0	7.6	46.1	.0	27.4	22.0	3.3	1.0	24.2	5.5	1.6	-46.5	-13.5	-43.2	-12.5	-41.0	-11.9
2001	229.1	.0	293.2	7.6	53.1	.0	32.4	23.3	2.5	.7	23.4	2.7	.7	-46.1	-12.1	-43.6	-11.5	-43.4	-11.4
2002	242.9	.0	311.2	7.6	61.2	.0	37.9	27.1	3.9	.9	23.0	-.3	-.1	-45.7	-10.9	-41.8	-10.0	-46.0	-11.0
2003	257.5	.0	329.3	7.6	70.7	.0	52.1	28.7	10.0	2.2	51.0	32.4	7.1	-44.0	-9.6	-34.0	-7.4	-11.6	-2.5
2004	257.5	.0	329.3	7.6	74.3	.0	57.1	.0	-17.2	-3.4	49.2	32.0	6.3	74.3	14.7	57.1	11.3	106.3	21.0
2005	257.5	.0	329.3	7.6	78.0	.0	62.3	.0	-15.7	-2.8	47.9	32.2	5.8	78.0	14.0	62.3	11.2	110.2	19.8
2006	257.5	.0	329.3	7.7	81.9	.0	69.0	.0	-12.9	-2.1	46.8	33.9	5.5	81.9	13.4	69.0	11.3	115.8	18.9
2007	257.5	.0	329.3	7.7	86.0	.0	78.2	.0	-7.8	-1.2	45.5	37.8	5.6	86.0	12.8	78.2	11.6	123.7	18.4
5-yr horizon (to 1992):					6.0	.0	3.3	23.1		20.4	1.5		-1.2		-39.4		-19.0		-40.6
10-yr horizon (to 1997):					39.4	.0	20.9	97.3		78.8	32.9		14.5		-140.6		-61.8		-126.1
15-yr horizon (to 2002):					106.5	.0	61.5	146.7		101.6	68.5		23.4		-206.7		-105.1		-183.3
20-yr horizon (to 2007):					176.8	.0	118.2	152.9		94.3	112.3		53.7		-161.4		-67.1		-107.7
27-yr horizon (to 2014):					250.7	.0	185.5	152.9		87.6	151.5		86.2		-87.4		.2		-1.2
30-yr horizon (to 2017):					275.5	.0	208.0	152.9		85.4	164.6		97.0		-62.7		22.7		34.4
40-yr horizon (to 2027):					336.1	.0	263.1	152.9		79.9	196.7		123.7		-2.1		77.8		121.5

All time horizons count 1987 as year 0. Beyond 2007 the benefit stream is assumed flat at the 2007 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

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BASE : #115; BASE CASE WITH BOTH TES AND RAC CAPABILITY 7/15/87

***** compared to *******

POLICY : #127; POLICY CASE WITH RAC ON AND S-SIDE DEFERRALS 17JUL87

****

BASIC ASSUMPTIONS

number of hours of peak averaging:	150.00
utility discount rate (curr):	10.00
customer discount rate (curr):	10.00
societal discount rate (curr):	10.00
general inflation rate :	5.00
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	10.23
PGandE capacity cost (1987$/kW) :	725.00
rac customer cap. cost (1987$/kW) :	.00
tes customer cap. cost (1987$/kW) :	.00
TES revenue loss factor (1987$/kW) :	.00
sensitivity factor for pksavs.n :	1.20
sens. factor for modest deferrals :	1.10

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	7.3	.Ø	.Ø	7.4	.9	.Ø	.2	.Ø	-.7	-.6	.Ø	-.7	-.6	-13.Ø	-1Ø.7	-13.7	-11.3	-13.7	-11.3
199Ø	11.4	.Ø	11.Ø	8.4	1.5	.Ø	1.7	4.1	4.3	3.2	.9	1.Ø	.8	-13.3	-1Ø.Ø	-9.1	-6.8	-12.3	-9.2
1991	17.7	.Ø	22.2	7.6	2.5	.Ø	2.3	4.3	4.1	2.8	.9	.6	.4	-14.Ø	-9.6	-9.9	-6.8	-13.4	-9.1
1992	27.7	.Ø	38.6	7.7	3.9	.Ø	3.3	6.7	6.2	3.8	.6	-.Ø	-.Ø	-14.7	-9.1	-8.5	-5.3	-14.7	-9.1
1993	43.2	.Ø	55.2	7.7	6.2	.Ø	4.8	7.1	5.7	3.2	6.6	5.2	2.9	-4Ø.3	-22.7	-34.6	-19.5	-35.1	-19.8
1994	67.4	.Ø	83.6	7.1	1Ø.1	.Ø	7.6	12.8	1Ø.3	5.3	6.5	4.Ø	2.1	-41.8	-21.4	-31.5	-16.1	-37.8	-19.4
1995	87.6	.Ø	112.1	7.1	14.1	.Ø	1Ø.Ø	13.4	9.3	4.4	6.3	2.2	1.Ø	-43.5	-2Ø.3	-34.1	-15.9	-41.3	-19.3
1996	113.8	.Ø	15Ø.6	7.3	19.1	.Ø	25.2	19.1	25.2	1Ø.7	27.5	33.6	14.2	-45.1	-19.1	-19.9	-8.4	-11.5	-4.9
1997	148.Ø	.Ø	189.2	7.6	25.8	.Ø	32.3	2Ø.1	26.6	1Ø.3	26.2	32.7	12.6	-45.6	-17.6	-18.9	-7.3	-12.9	-5.Ø
1998	192.4	.Ø	225.1	7.6	35.2	.Ø	41.5	19.6	25.9	9.1	25.5	31.8	11.1	-43.3	-15.2	-17.3	-6.1	-11.5	-4.Ø
1999	2Ø3.9	.Ø	26Ø.9	7.6	4Ø.2	.Ø	47.9	2Ø.6	28.3	9.Ø	24.6	32.4	1Ø.3	-45.3	-14.4	-17.Ø	-5.4	-12.9	-4.1
2ØØØ	216.2	.Ø	277.Ø	7.6	46.1	.Ø	54.6	9.7	18.2	5.3	24.1	32.6	9.4	-46.5	-13.5	-28.3	-8.2	-13.9	-4.Ø
2ØØ1	229.1	.Ø	293.2	7.6	53.1	.Ø	64.5	1Ø.3	21.6	5.7	23.3	34.7	9.1	-46.1	-12.1	-24.5	-6.4	-11.4	-3.Ø
2ØØ2	242.9	.Ø	311.2	7.6	61.2	.Ø	75.3	12.Ø	26.1	6.2	22.9	37.Ø	8.9	-45.7	-1Ø.9	-19.6	-4.7	-8.7	-2.1
2ØØ3	257.5	.Ø	329.3	7.6	7Ø.7	.Ø	1Ø4.4	12.7	46.3	1Ø.1	5Ø.9	84.6	18.4	-44.Ø	-9.6	2.3	.5	4Ø.6	8.8
2ØØ4	257.5	.Ø	329.3	7.6	74.3	.Ø	114.8	.Ø	4Ø.5	8.Ø	48.9	89.5	17.7	74.3	14.7	114.8	22.7	163.7	32.4
2ØØ5	257.5	.Ø	329.3	7.6	78.Ø	.Ø	125.6	.Ø	47.6	8.6	47.6	95.2	17.1	78.Ø	14.Ø	125.6	22.6	173.2	31.2
2ØØ6	257.5	.Ø	329.3	7.7	81.9	.Ø	139.3	.Ø	57.4	9.4	46.3	1Ø3.7	17.Ø	81.9	13.4	139.3	22.8	185.6	3Ø.3
2ØØ7	257.5	.Ø	329.3	7.7	86.Ø	.Ø	157.6	.Ø	71.6	1Ø.6	45.2	116.8	17.4	86.Ø	12.8	157.6	23.4	2Ø2.8	3Ø.1
5-yr horizon (to 1992):					6.Ø	.Ø	5.1	1Ø.2		9.2	1.6		.6		-39.4		-3Ø.2		-38.8
1Ø-yr horizon (to 1997):					39.4	.Ø	39.5	42.9		43.Ø	33.3		33.4		-14Ø.6		-97.5		-1Ø7.1
15-yr horizon (to 2ØØ2):					1Ø6.5	.Ø	12Ø.1	64.7		78.4	68.7		82.3		-2Ø6.7		-128.3		-124.4
2Ø-yr horizon (to 2ØØ7):					176.8	.Ø	234.3	67.5		125.Ø	112.4		169.9		-161.4		-36.3		8.5
27-yr horizon (to 2Ø14):					25Ø.7	.Ø	369.9	67.5		186.6	151.2		27Ø.4		-87.4		99.2		183.Ø
3Ø-yr horizon (to 2Ø17):					275.5	.Ø	415.2	67.5		2Ø7.2	164.3		3Ø4.Ø		-62.7		144.5		241.3
4Ø-yr horizon (to 2Ø27):					336.1	.Ø	526.3	67.5		257.7	196.1		386.3		-2.1		255.6		384.2

All time horizons count 1987 as year Ø. Beyond 2ØØ7 the benefit stream is assumed flat at the 2ØØ7 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

****

BASE : #124; BASE CASE WITH DOUBLING OF OIL PRICES 7/28/87

***** compared to *******

POLICY : #132; RAC CASE WITH SS DEF & DOUBLING OF OIL PRICES 8/8/87

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BASIC ASSUMPTIONS

number of hours of peak averaging:	15Ø.ØØ
utility discount rate (curr):	1Ø.ØØ
customer discount rate (curr):	1Ø.ØØ
societal discount rate (curr):	1Ø.ØØ
general inflation rate :	5.ØØ
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	1Ø.23
PGandE capacity cost (1987$/kW) :	32Ø.ØØ
rac customer cap. cost (1987$/kW) :	.ØØ
tes customer cap. cost (1987$/kW) :	.ØØ
TES revenue loss factor (1987$/kW) :	.ØØ
sensitivity factor for pksavs.n :	1.2Ø
sens. factor for modest deferrals :	1.1Ø

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	7.3	.Ø	.Ø	7.4	.9	.Ø	.2	.Ø	-.7	-.6	-.Ø	-.7	-.6	-13.Ø	-1Ø.7	-13.7	-11.3	-13.7	-11.3
199Ø	11.4	.Ø	11.Ø	8.1	1.5	.Ø	1.2	4.1	3.8	2.8	.8	.4	.3	-13.3	-1Ø.Ø	-9.6	-7.2	-12.9	-9.7
1991	17.7	.Ø	22.2	7.7	2.5	.Ø	1.5	4.3	3.3	2.2	.8	-.3	-.2	-14.Ø	-9.6	-1Ø.7	-7.3	-14.3	-9.8
1992	27.7	.Ø	38.6	7.7	3.9	.Ø	2.Ø	6.7	4.9	3.Ø	.7	-1.2	-.7	-14.7	-9.1	-9.8	-6.1	-15.9	-9.9
1993	43.2	.Ø	55.2	7.7	6.2	.Ø	2.7	7.1	3.6	2.Ø	6.5	3.Ø	1.6	-4Ø.3	-22.7	-36.7	-2Ø.7	-37.3	-21.1
1994	67.4	.Ø	83.6	7.1	1Ø.1	.Ø	3.9	12.8	6.6	3.3	6.4	.2	.1	-41.8	-21.4	-35.2	-18.Ø	-41.6	-21.3
1995	87.6	.Ø	112.1	7.1	14.1	.Ø	5.1	13.4	4.4	2.Ø	6.Ø	-3.Ø	-1.3	-43.5	-2Ø.3	-39.Ø	-18.2	-46.4	-21.7
1996	113.8	.Ø	15Ø.6	7.3	19.1	.Ø	12.7	19.1	12.7	5.2	27.3	2Ø.9	8.6	-45.1	-19.1	-32.4	-13.7	-24.2	-1Ø.3
1997	148.Ø	.Ø	189.2	7.6	25.8	.Ø	16.3	2Ø.1	1Ø.6	4.Ø	26.2	16.7	6.2	-45.6	-17.6	-34.9	-13.5	-28.9	-11.1
1998	192.4	.Ø	225.1	7.6	35.2	.Ø	2Ø.9	19.6	5.3	1.8	25.5	11.2	3.8	-43.3	-15.2	-37.9	-13.3	-32.1	-11.2
1999	2Ø3.9	.Ø	26Ø.9	7.6	4Ø.2	.Ø	24.1	2Ø.6	4.5	1.4	24.7	8.7	2.6	-45.3	-14.4	-4Ø.8	-13.Ø	-36.6	-11.7
2ØØØ	216.2	.Ø	277.Ø	7.6	46.1	.Ø	27.4	9.7	-9.Ø	-2.5	24.2	5.5	1.5	-46.5	-13.5	-55.5	-16.1	-41.Ø	-11.9
2ØØ1	229.1	.Ø	293.2	7.6	53.1	.Ø	32.4	1Ø.3	-1Ø.5	-2.6	23.4	2.7	.7	-46.1	-12.1	-56.6	-14.9	-43.4	-11.4
2ØØ2	242.9	.Ø	311.2	7.6	61.2	.Ø	37.9	12.Ø	-11.3	-2.6	23.Ø	-.3	-.1	-45.7	-1Ø.9	-57.Ø	-13.6	-46.Ø	-11.Ø
2ØØ3	257.5	.Ø	329.3	7.6	7Ø.7	.Ø	52.1	12.7	-6.Ø	-1.2	51.Ø	32.4	6.7	-44.Ø	-9.6	-5Ø.Ø	-1Ø.9	-11.6	-2.5
2ØØ4	257.5	.Ø	329.3	7.6	74.3	.Ø	57.1	.Ø	-17.2	-3.2	49.2	32.Ø	6.Ø	74.3	14.7	57.1	11.3	1Ø6.3	21.Ø
2ØØ5	257.5	.Ø	329.3	7.6	78.Ø	.Ø	62.3	.Ø	-15.7	-2.6	47.9	32.2	5.4	78.Ø	14.Ø	62.3	11.2	11Ø.2	19.8
2ØØ6	257.5	.Ø	329.3	7.7	81.9	.Ø	69.Ø	.Ø	-12.9	-2.Ø	46.8	33.9	5.2	81.9	13.4	69.Ø	11.3	115.8	18.9
2ØØ7	257.5	.Ø	329.3	7.7	86.Ø	.Ø	78.2	.Ø	-7.8	-1.1	45.5	37.8	5.2	86.Ø	12.8	78.2	11.6	123.7	18.4
5-yr horizon (to 1992):					5.9	.Ø	3.3	1Ø.1		7.4	1.5		-1.2		-39.4		-31.9		-4Ø.6
1Ø-yr horizon (to 1997):					38.3	.Ø	2Ø.3	41.8		23.9	31.9		14.Ø		-14Ø.6		-116.1		-126.1
15-yr horizon (to 2ØØ2):					1Ø2.3	.Ø	59.Ø	62.7		19.3	65.8		22.5		-2Ø6.7		-187.Ø		-183.3
2Ø-yr horizon (to 2ØØ7):					168.2	.Ø	112.1	65.3		9.2	1Ø7.Ø		5Ø.9		-161.4		-152.5		-1Ø7.7
27-yr horizon (to 2Ø14):					236.Ø	.Ø	173.8	65.3		3.1	142.9		8Ø.7		-87.4		-85.2		-1.2
3Ø-yr horizon (to 2Ø17):					258.2	.Ø	194.Ø	65.3		1.1	154.6		9Ø.5		-62.7		-62.7		34.4
4Ø-yr horizon (to 2Ø27):					311.4	.Ø	242.4	65.3		-3.7	182.8		113.8		-2.1		-7.6		121.5

All time horizons count 1987 as year Ø. Beyond 2ØØ7 the benefit stream is assumed flat at the 2ØØ7 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

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BASE : #115; BASE CASE WITH BOTH TES AND RAC CAPABILITY 7/15/87

***** compared to *******

POLICY : #127; POLICY CASE WITH RAC ON AND S-SIDE DEFERRALS 17JUL87

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BASIC ASSUMPTIONS

number of hours of peak averaging: 15Ø.ØØ
utility discount rate (curr): 1Ø.4Ø
customer discount rate (curr): 1Ø.ØØ
societal discount rate (curr): 1Ø.ØØ
general inflation rate : 5.ØØ
retail price index for 1987 : 1.52
1987 tier2 price (c/kWh) : 1Ø.23
PGandE capacity cost (1987$/kW) : 32Ø.ØØ
rac customer cap. cost (1987$/kW) : .ØØ
tes customer cap. cost (1987$/kW) : .ØØ
TES revenue loss factor (1987$/kW) : .ØØ
sensitivity factor for pksavs.n : 1.2Ø
sens. factor for modest deferrals : 1.1Ø

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	7.3	.0	.0	7.4	.9	.0	.2	.0	-.7	-.6	-.0	-.7	-.6	-13.0	-10.7	-13.7	-11.3	-13.7	-11.3
1990	11.4	.0	11.0	8.1	1.5	.0	1.2	9.3	8.9	6.6	.8	.4	.3	-13.3	-10.0	-4.4	-3.3	-12.9	-9.7
1991	17.7	.0	22.2	7.7	2.5	.0	1.5	9.8	8.8	5.9	.8	-.3	-.2	-14.0	-9.6	-5.2	-3.6	-14.3	-9.8
1992	27.7	.0	38.6	7.7	3.9	.0	2.0	15.2	13.4	8.1	.7	-1.2	-.7	-14.7	-9.1	-1.3	-.8	-15.9	-9.9
1993	43.2	.0	55.2	7.7	6.2	.0	2.7	16.1	12.6	6.9	6.5	3.0	1.6	-40.3	-22.7	-27.7	-15.7	-37.3	-21.1
1994	67.4	.0	83.6	7.1	10.1	.0	3.9	29.0	22.8	11.4	6.4	.2	.1	-41.8	-21.4	-19.0	-9.7	-41.6	-21.3
1995	87.6	.0	112.1	7.1	14.1	.0	5.1	30.5	21.5	9.7	6.0	-3.0	-1.3	-43.5	-20.3	-22.0	-10.3	-46.4	-21.7
1996	113.8	.0	150.6	7.3	19.1	.0	12.7	43.3	36.9	15.1	27.3	20.9	8.6	-45.1	-19.1	-8.2	-3.5	-24.2	-10.3
1997	148.0	.0	189.2	7.6	25.8	.0	16.3	45.6	36.1	13.4	26.2	16.7	6.2	-45.6	-17.6	-9.4	-3.6	-28.9	-11.1
1998	192.4	.0	225.1	7.6	35.2	.0	20.9	44.5	30.2	10.2	25.5	11.2	3.8	-43.3	-15.2	-13.1	-4.6	-32.1	-11.2
1999	203.9	.0	260.9	7.6	40.2	.0	24.1	46.6	30.5	9.3	24.7	8.7	2.6	-45.3	-14.4	-14.8	-4.7	-36.6	-11.7
2000	216.2	.0	277.0	7.6	46.1	.0	27.4	22.0	3.3	.9	24.2	5.5	1.5	-46.5	-13.5	-43.2	-12.5	-41.0	-11.9
2001	229.1	.0	293.2	7.6	53.1	.0	32.4	23.3	2.5	.6	23.4	2.7	.7	-46.1	-12.1	-43.6	-11.5	-43.4	-11.4
2002	242.9	.0	311.2	7.6	61.2	.0	37.9	27.1	3.9	.9	23.0	-.3	-.1	-45.7	-10.9	-41.8	-10.0	-46.0	-11.0
2003	257.5	.0	329.3	7.6	70.7	.0	52.1	28.7	10.0	2.1	51.0	32.4	6.7	-44.0	-9.6	-34.0	-7.4	-11.6	-2.5
2004	257.5	.0	329.3	7.6	74.3	.0	57.1	.0	-17.2	-3.2	49.2	32.0	6.0	74.3	14.7	57.1	11.3	106.3	21.0
2005	257.5	.0	329.3	7.6	78.0	.0	62.3	.0	-15.7	-2.6	47.9	32.2	5.4	78.0	14.0	62.3	11.2	110.2	19.8
2006	257.5	.0	329.3	7.7	81.9	.0	69.0	.0	-12.9	-2.0	46.8	33.9	5.2	81.9	13.4	69.0	11.3	115.8	18.9
2007	257.5	.0	329.3	7.7	86.0	.0	78.2	.0	-7.8	-1.1	45.5	37.8	5.2	86.0	12.8	78.2	11.6	123.7	18.4
5-yr horizon (to 1992):					5.9	.0	3.3	22.8		20.1	1.5		-1.2		-39.4		-19.0		-40.6
10-yr horizon (to 1997):					38.3	.0	20.3	94.7		76.8	31.9		14.0		-140.6		-61.8		-126.1
15-yr horizon (to 2002):					102.3	.0	59.0	142.0		98.7	65.8		22.5		-206.7		-105.1		-183.3
20-yr horizon (to 2007):					168.2	.0	112.1	147.9		91.8	107.0		50.9		-161.4		-67.1		-107.7
27-yr horizon (to 2014):					236.0	.0	173.8	147.9		85.7	142.9		80.7		-87.4		.2		-1.2
30-yr horizon (to 2017):					258.2	.0	194.0	147.9		83.7	154.6		90.5		-62.7		22.7		34.4
40-yr horizon (to 2027):					311.4	.0	242.4	147.9		78.9	182.8		113.8		-2.1		77.8		121.5

All time horizons count 1987 as year 0. Beyond 2007 the benefit stream is assumed flat at the 2007 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

****

BASE : #115; BASE CASE WITH BOTH TES AND RAC CAPABILITY 7/15/87

***** compared to *******

POLICY : #127; POLICY CASE WITH RAC ON AND S-SIDE DEFERRALS 17JUL87

****

BASIC ASSUMPTIONS

number of hours of peak averaging:	150.00
utility discount rate (curr):	10.40
customer discount rate (curr):	10.00
societal discount rate (curr):	10.00
general inflation rate :	5.00
retail price index for 1987 :	1.52
1987 tier2 price (c/kWh) :	10.23
PGandE capacity cost (1987$/kW) :	725.00
rac customer cap. cost (1987$/kW) :	.00
tes customer cap. cost (1987$/kW) :	.00
TES revenue loss factor (1987$/kW) :	.00
sensitivity factor for pksavs.n :	1.20
sens. factor for modest deferrals :	1.10

FINANCIAL EFFECTS

year	rac (GWh)	tes (GWh)	chpk (MW)	plf (%)	raclr (M$)	teslr (M$)	voc.ch (M$)	cv1 (M$)	nbpg1 (M$)	pvpg1 (M87$)	cv2 (M$)	nbpg2 (M$)	pvpg2 (M87$)	nbcu1 (M$)	pvcu1 (M87$)	nbso1 (M$)	pvso1 (M$)	nbso2 (M$)	pvso2 (M$)
1989	7.3	.0	.0	7.4	.9	.0	.2	.0	-.7	-.6	.0	-.7	-.6	-13.0	-10.7	-13.7	-11.3	-13.7	-11.3
1990	11.4	.0	11.0	8.4	1.5	.0	1.7	4.1	4.3	3.2	.9	1.0	.8	-13.3	-10.0	-9.1	-6.8	-12.3	-9.2
1991	17.7	.0	22.2	7.6	2.5	.0	2.3	4.3	4.1	2.8	.9	.6	.4	-14.0	-9.6	-9.9	-6.8	-13.4	-9.1
1992	27.7	.0	38.6	7.7	3.9	.0	3.3	6.7	6.2	3.8	.6	-.0	-.0	-14.7	-9.1	-8.5	-5.3	-14.7	-9.1
1993	43.2	.0	55.2	7.7	6.2	.0	4.8	7.1	5.7	3.1	6.6	5.2	2.9	-40.3	-22.7	-34.6	-19.5	-35.1	-19.8
1994	67.4	.0	83.6	7.1	10.1	.0	7.6	12.8	10.3	5.2	6.5	4.0	2.0	-41.8	-21.4	-31.5	-16.1	-37.8	-19.4
1995	87.6	.0	112.1	7.1	14.1	.0	10.0	13.4	9.3	4.2	6.3	2.2	1.0	-43.5	-20.3	-34.1	-15.9	-41.3	-19.3
1996	113.8	.0	150.6	7.3	19.1	.0	25.2	19.1	25.2	10.3	27.5	33.6	13.8	-45.1	-19.1	-19.9	-8.4	-11.5	-4.9
1997	148.0	.0	189.2	7.6	25.8	.0	32.3	20.1	26.6	9.9	26.2	32.7	12.2	-45.6	-17.6	-18.9	-7.3	-12.9	-5.0
1998	192.4	.0	225.1	7.6	35.2	.0	41.5	19.6	25.9	8.7	25.5	31.8	10.7	-43.3	-15.2	-17.3	-6.1	-11.5	-4.0
1999	203.9	.0	260.9	7.6	40.2	.0	47.9	20.6	28.3	8.6	24.6	32.4	9.9	-45.3	-14.4	-17.0	-5.4	-12.9	-4.1
2000	216.2	.0	277.0	7.6	46.1	.0	54.6	9.7	18.2	5.0	24.1	32.6	9.0	-46.5	-13.5	-28.3	-8.2	-13.9	-4.0
2001	229.1	.0	293.2	7.6	53.1	.0	64.5	10.3	21.6	5.4	23.3	34.7	8.7	-46.1	-12.1	-24.5	-6.4	-11.4	-3.0
2002	242.9	.0	311.2	7.6	61.2	.0	75.3	12.0	26.1	5.9	22.9	37.0	8.4	-45.7	-10.9	-19.6	-4.7	-8.7	-2.1
2003	257.5	.0	329.3	7.6	70.7	.0	104.4	12.7	46.3	9.5	50.9	84.6	17.4	-44.0	-9.6	2.3	.5	40.6	8.8
2004	257.5	.0	329.3	7.6	74.3	.0	114.8	.0	40.5	7.5	48.9	89.5	16.6	74.3	14.7	114.8	22.7	163.7	32.4
2005	257.5	.0	329.3	7.6	78.0	.0	125.6	.0	47.6	8.0	47.6	95.2	16.0	78.0	14.0	125.6	22.6	173.2	31.2
2006	257.5	.0	329.3	7.7	81.9	.0	139.3	.0	57.4	8.8	46.3	103.7	15.8	81.9	13.4	139.3	22.8	185.6	30.3
2007	257.5	.0	329.3	7.7	86.0	.0	157.6	.0	71.6	9.9	45.2	116.8	16.1	86.0	12.8	157.6	23.4	202.8	30.1
5-yr horizon (to 1992):					5.9	.0	5.0	10.1		9.1	1.6		.6		-39.4		-30.2		-38.8
10-yr horizon (to 1997):					38.3	.0	38.3	41.8		41.9	32.3		32.4		-140.6		-97.5		-107.1
15-yr horizon (to 2002):					102.3	.0	115.2	62.7		75.6	66.1		79.1		-206.7		-128.3		-124.4
20-yr horizon (to 2007):					168.2	.0	222.2	65.3		119.3	107.0		161.1		-161.4		-36.3		8.5
27-yr horizon (to 2014):					236.0	.0	346.5	65.3		175.8	142.7		253.2		-87.4		99.2		183.0
30-yr horizon (to 2017):					258.2	.0	387.2	65.3		194.3	154.4		283.4		-62.7		144.5		241.3
40-yr horizon (to 2027):					311.4	.0	484.7	65.3		238.6	182.3		355.7		-2.1		255.6		384.2

All time horizons count 1987 as year 0. Beyond 2007 the benefit stream is assumed flat at the 2007 level.
Time horizon values of the raclr, teslr, voc.ch, cv1, and cv2 streams discounted at the utility discount rate.

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BASE : #124; BASE CASE WITH DOUBLING OF OIL PRICES 7/28/87

***** compared to *******

POLICY : #132; RAC CASE WITH SS DEF & DOUBLING OF OIL PRICES 8/8/87

****

BASIC ASSUMPTIONS

number of hours of peak averaging	:	150.00
utility discount rate (curr)	:	10.40
customer discount rate (curr)	:	10.00
societal discount rate (curr)	:	10.00
general inflation rate	:	5.00
retail price index for 1987	:	1.52
1987 tier2 price (c/kWh)	:	10.23
PGandE capacity cost (1987$/kW)	:	320.00
rac customer cap. cost (1987$/kW)	:	.00
tes customer cap. cost (1987$/kW)	:	.00
TES revenue loss factor (1987$/kW)	:	.00
sensitivity factor for pksavs.n	:	1.20
sens. factor for modest deferrals	:	1.10

Appendix E

LMSTM Load Shapes for the Residential Airconditioning Decrement

season: 1 daytype: 4 av. peak dec.: 0 MW av. dec.: 2 MWh no. days: 6

.000	.000	.000	.000	.000	.000	.800	.800	.000	.800	.000	.000
.000	.000	.000	1.000	.000	.000	.000	.000	.000	.000	.000	.000

season: 1 daytype: 3 av. peak dec.: 9 MW av. dec.: 50 MWh no. days: 38

.000	.000	.011	.011	.000	.036	.036	.050	.022	.000	.069	.187
.408	.598	.738	.948	1.000	.755	.311	.080	.041	.000	.000	.000

season: 1 daytype: 2 av. peak dec.: 25 MW av. dec.: 134 MWh no. days: 42

.000	.004	.004	.000	.004	.004	.007	.009	.005	.008	.059	.168
.416	.732	.946	1.000	.868	.587	.297	.060	.013	.008	.004	.000

season: 1 daytype: 1 av. peak dec.: 28 MW av. dec.: 171 MWh no. days: 34

.004	.000	.004	.008	.009	.004	.008	.012	.004	.056	.132	.299
.610	.850	.974	1.000	.933	.655	.310	.096	.039	.000	.018	.000

season: 2 daytype: 4 av. peak dec.: 486 MW av. dec.:3809 MWh no. days: 4

.037	.008	.006	.003	.003	.003	.004	.012	.054	.188	.363	.558
.800	.958	1.000	.976	.873	.766	.555	.292	.149	.102	.066	.060

season: 2 daytype: 3 av. peak dec.: 351 MW av. dec.:2702 MWh no. days: 14

.032	.015	.007	.006	.005	.004	.004	.019	.056	.141	.287	.460
.714	.923	1.000	.991	.903	.784	.588	.350	.173	.100	.070	.053

season: 2 daytype: 2 av. peak dec.: 207 MW av. dec.:1481 MWh no. days: 48

.028	.011	.006	.003	.003	.001	.001	.010	.033	.100	.213	.407
.647	.861	.965	1.000	.936	.765	.546	.272	.135	.095	.061	.047

season: 2 daytype: 1 av. peak dec.: 246 MW av. dec.:1861 MWh no. days: 26

.039	.020	.009	.006	.004	.001	.002	.017	.050	.123	.252	.444
.706	.920	.988	1.000	.939	.785	.574	.295	.147	.106	.064	.054

season: 3 daytype: 4 av. peak dec.: 0 MW av. dec.: 2 MWh no. days: 6

1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

season: 3 daytype: 3 av. peak dec.: 18 MW av. dec.: 114 MWh no. days: 34

.000	.000	.006	.006	.006	.019	.030	.032	.008	.051	.141	.303
.561	.870	1.000	.970	.814	.643	.405	.155	.071	.051	.040	.043

season: 3 daytype: 2 av. peak dec.: 48 MW av. dec.: 287 MWh no. days: 26

.018	.000	.000	.000	.000	.000	.000	.000	.006	.049	.140	.354
.612	.803	.974	1.000	.965	.524	.251	.089	.047	.053	.032	.037

season: 3 daytype: 1 av. peak dec.: 33 MW av. dec.: 178 MWh no. days: 26

.000	.000	.000	.000	.000	.005	.011	.005	.005	.000	.046	.181
.439	.709	.927	1.000	.875	.518	.314	.099	.066	.062	.030	.026

season: 4 daytype: 4 av. peak dec.: 401 MW av. dec.:3132 MWh no. days: 3

.009	.000	.000	.000	.000	.000	.000	.029	.054	.208	.373	.583
.803	.985	1.000	.980	.915	.802	.605	.284	.091	.051	.017	.014

season: 4 daytype: 3 av. peak dec.: 271 MW av. dec.:2155 MWh no. days: 3

.006	.006	.000	.000	.000	.000	.000	.016	.045	.174	.259	.488
.772	.996	.982	1.000	.984	.863	.667	.355	.120	.104	.048	.048

season: 4 daytype: 2 av. peak dec.: 101 MW av. dec.: 680 MWh no. days: 37

.018	.005	.000	.000	.000	.000	.000	.002	.017	.061	.164	.343
.589	.849	.980	1.000	.934	.726	.509	.289	.128	.065	.025	.015

season: 4 daytype: 1 av. peak dec.: 132 MW av. dec.: 953 MWh no. days: 18

.008	.002	.000	.000	.000	.000	.000	.000	.027	.075	.250	.446
.674	.884	1.000	.988	.905	.784	.582	.320	.112	.069	.033	.025

Appendix F

Table A6.1

Forecast Numbers of Customers in the Rate Regions

(potential room and central air customers - thousands)

year	D		R		S		T		X	
	no.	ch.	no.	ch.	no.	ch.	no.	ch.	no.	ch.
1987	258.30	12.30	292.21	13.91	362.46	17.26	809.52	8.02	1208.37	29.47
1988	271.21	12.91	306.83	14.61	380.58	18.12	817.61	8.10	1238.58	30.21
1989	284.78	13.56	322.17	15.34	399.61	19.03	825.79	8.18	1269.55	30.96
1990	299.01	14.24	338.28	16.11	419.59	19.98	834.04	8.26	1301.28	31.74
1991	313.97	14.95	355.19	16.91	440.57	20.98	842.38	8.34	1333.82	32.53
1992	329.66	15.70	372.95	17.76	462.60	22.03	850.81	8.42	1367.16	33.35
1993	346.15	16.48	391.60	18.65	485.73	23.13	859.32	8.51	1401.34	34.18
1994	363.45	17.31	411.18	19.58	510.02	24.29	867.91	8.59	1436.37	35.03
1995	381.63	18.17	431.73	20.56	535.52	25.50	876.59	8.68	1472.28	35.91
1996	400.71	19.08	453.32	21.59	562.29	26.78	885.35	8.77	1509.09	36.81
1997	420.74	20.04	475.99	22.67	590.41	28.11	894.21	8.85	1546.82	37.73
1998	441.78	21.04	499.79	23.80	619.93	29.52	903.15	8.94	1585.49	38.67
1999	463.87	22.09	524.78	24.99	650.93	31.00	912.18	9.03	1625.13	39.64
2000	487.06	23.19	551.01	26.24	683.47	32.55	921.30	9.12	1665.75	40.63
2001	511.42	24.35	578.57	27.55	717.65	34.17	930.52	9.21	1707.40	41.64
2002	536.99	25.57	607.49	28.93	753.53	35.88	939.82	9.31	1750.08	42.68
2003	563.84	26.85	637.87	30.37	791.20	37.68	949.22	9.40	1793.83	43.75

assuming that escalations are fixed 1980-2003,
and the trajectory passes through the 1986 point
percent growth rates assumed are: D = 5, R = 5, S = 5, T = 1, X = 2

Table A6.2

Forecast Numbers of Customers in the Rate Regions

(potential heat pump customers - thousands)

year	D		R		S		T		X	
	no.	ch.	no.	ch.	no.	ch.	no.	ch.	no.	ch.
1987	69.62	3.31	52.58	2.50	97.80	4.66	102.62	1.02	155.48	3.79
1988	73.10	3.48	55.21	2.63	102.69	4.89	103.64	1.03	159.37	3.89
1989	76.75	3.65	57.97	2.76	107.82	5.13	104.68	1.04	163.35	3.98
1990	80.59	3.84	60.87	2.90	113.21	5.39	105.73	1.05	167.44	4.08
1991	84.62	4.03	63.92	3.04	118.87	5.66	106.78	1.06	171.62	4.19
1992	88.85	4.23	67.11	3.20	124.82	5.94	107.85	1.07	175.91	4.29
1993	93.29	4.44	70.47	3.36	131.06	6.24	108.93	1.08	180.31	4.40
1994	97.96	4.66	73.99	3.52	137.61	6.55	110.02	1.09	184.82	4.51
1995	102.85	4.90	77.69	3.70	144.49	6.88	111.12	1.10	189.44	4.62
1996	108.00	5.14	81.58	3.88	151.72	7.22	112.23	1.11	194.18	4.74
1997	113.40	5.40	85.65	4.08	159.30	7.59	113.35	1.12	199.03	4.85
1998	119.07	5.67	89.94	4.28	167.27	7.97	114.49	1.13	204.01	4.98
1999	125.02	5.95	94.43	4.50	175.63	8.36	115.63	1.14	209.11	5.10
2000	131.27	6.25	99.15	4.72	184.41	8.78	116.79	1.16	214.33	5.23
2001	137.83	6.56	104.11	4.96	193.63	9.22	117.95	1.17	219.69	5.36
2002	144.72	6.89	109.32	5.21	203.31	9.68	119.13	1.18	225.18	5.49
2003	151.96	7.24	114.78	5.47	213.48 10.17	120.33	1.19	230.81	5.63	

assuming that escalations are fixed 1980-2003,
and the trjectory passes through the 1986 point
growth rates assumed are: D = 5, R = 5, S = 5, T = 1, X = 2