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## APPLIED SCIENCE DIVISION

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J.H. Eto, J. McMahon, and P. Chan

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*FINANCIAL IMPACTS ON UTILITIES OF LOAD SHAPE CHANGES PROJECT*

*STAGE II TECHNICAL REPORT*

# The Pacific Gas and Electric Company


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# THE PACIFIC GAS AND ELECTRIC COMPANY

## I INTRODUCTION

The goal of this LBL project is to develop tools and procedures that measure the financial impacts of load shape changes to utility stockholders. In this application, we study the financial impacts of exogenous policies that raise the efficiencies of residential appliances. The analysis is based on detailed forecasts of energy use by computer simulation models developed at LBL. These models disaggregate both annual energy use and hourly system electric loads at the end-use level. This detail is essential for calculating production and capacity cost benefits, and tariff-class specific revenue changes. We are thus able to combine several analytical procedures commonly employed by the industry independent of one another into an integrated assessment of the impacts of load shape changes on utility shareholders.

This report is the technical documentation for our case study of the Pacific Gas and Electric Company (PG&E). The purpose is to provide the interested reader with the underlying assumptions and modeling procedures used to assess the financial impacts of policies that increase the efficiency of residential appliances. A separate document describes our conclusions.[1] This latter document also reports on case studies of the financial impacts of load shape changes on the Detroit Edison Company and the Virginia Electric and Power Company.[2,3]

We remind the reader that the present study is a simplified and stylized characterization of the Pacific Gas and Electric Company. For example, we have chosen to concentrate efforts on only the eight largest rate classes in the four most populous geographic regions of the Company. Together, these rate classes constitute 75 to 80 % of PG&E residential sales or about 25 % of total system sales. Similarly, we have described the structure of PG&E marginal production costs independent of specific financial assumptions regarding fuel prices.

Even a simplified characterization of an electric utility, however, requires substantial data to run the models and to calculate financial impacts. We were very fortunate in choosing PG&E as a case study because of the ready availability of the necessary input and load data in an easily accessed format. PG&E staff members were extremely helpful in providing the bulk of this information as well as timely advice and guidance.

The structure of the report is as follows. In the first section, we describe the energy forecast and hourly load models. The emphasis in this section is on data sources and input assumptions, and on procedures developed to calibrate the models to historic records of sales and demands. The second section describes the valuation of the energy and demand impacts forecast by the models as financial impacts on shareholders.

# II MODELING LOAD SHAPE CHANGES

## 1. Introduction

LBL has developed two complementary models for forecasting residential electricity consumption and load shapes. The first, the LBL Residential Energy Model,[4] is used to forecast annual residential electricity sales. The second model, the LBL Residential Hourly Demand and Peak Load Model, takes the output of the first model and distributes the annual data over the hours of the year.[5]

In this section, we describe how these models were used to forecast the load shape and energy impacts of policies to increase the efficiency of residential appliances in the PG&E service territory. The discussion is developed in four stages:

- The models and method employed to calculate the load shape and energy impacts of appliance efficiency standards.
- The identification of data sources for the LBL Residential Energy Model and the LBL Residential Hourly Demand and Peak Load Model.
- The calibration of the models using historic PG&E electricity sales and loads.
- The energy and demand results for the base- and policy-case simulations.

## 2. Models and Methods

The LBL Residential Energy Model was designed to provide a consistent framework for integrating engineering and economic data at the end-use level for residential energy use. It was originally developed at the Oak Ridge National Laboratory[6] and subsequently modified by LBL.[7] The inputs consist of economic, demographic, and engineering characteristics of and projections for the energy-using stock.

The second model, the LBL Residential Hourly and Peak Demand Model, is primarily an engineering model that relates empirical observations of electricity end-use to time of year and day, and, for weather-sensitive end-uses, temperature. The inputs required are weather data file of hourly temperatures, and the end-use specific forecasts of energy use generated by the first model.

For PG&E, we modeled the two largest residential rate classes in each of the four most populous geographic regions/rate zones of the service territory (R, S, T, and X). Together, the eight rate classes account for 75 to 80 % of PG&E's residential sales. Figure 1 illustrates these regions.

The method used to calculate the energy and load shape impacts of standards for minimum appliance efficiencies is straight forward. The models are first calibrated to historical data. Projections of future energy demands from the calibrated set of inputs constitutes a base or reference case. The policy case also begins with the set of calibrated inputs. At a point in the future, in this case 1987, standards are introduced. The effect of the standards is simulated by constraining the minimum appliance efficiency that the model can select. Since efficient appliances are more expensive, the model predicts not only reduced consumption per unit, but also a different pattern of appliance sales. Differences between the policy case and the base case are the impacts of the policy.

For PG&E, we evaluated two policies to raise the efficiency of residential appliances. The first was a standard that mandates minimum efficiencies consistent with those used in the Detroit Edison Co (DECO) study.[2] This policy case is comprised of across-the-board Level-8 appliance standards developed at LBL.[8] Since California already has appliance standards in place, albeit mandating efficiency levels different from LBL Level-8, we expected additional standards to have a small effect. For this reason, we also examined the impact of a technology-forcing air-conditioner standard in addition to Level-8. This standard, we hypothesized, would yield substantial capacity benefits. Table 1 summarizes the efficiencies called for in the standards.

Figure 1. Service territory of the Pacific Gas and Electric Company.

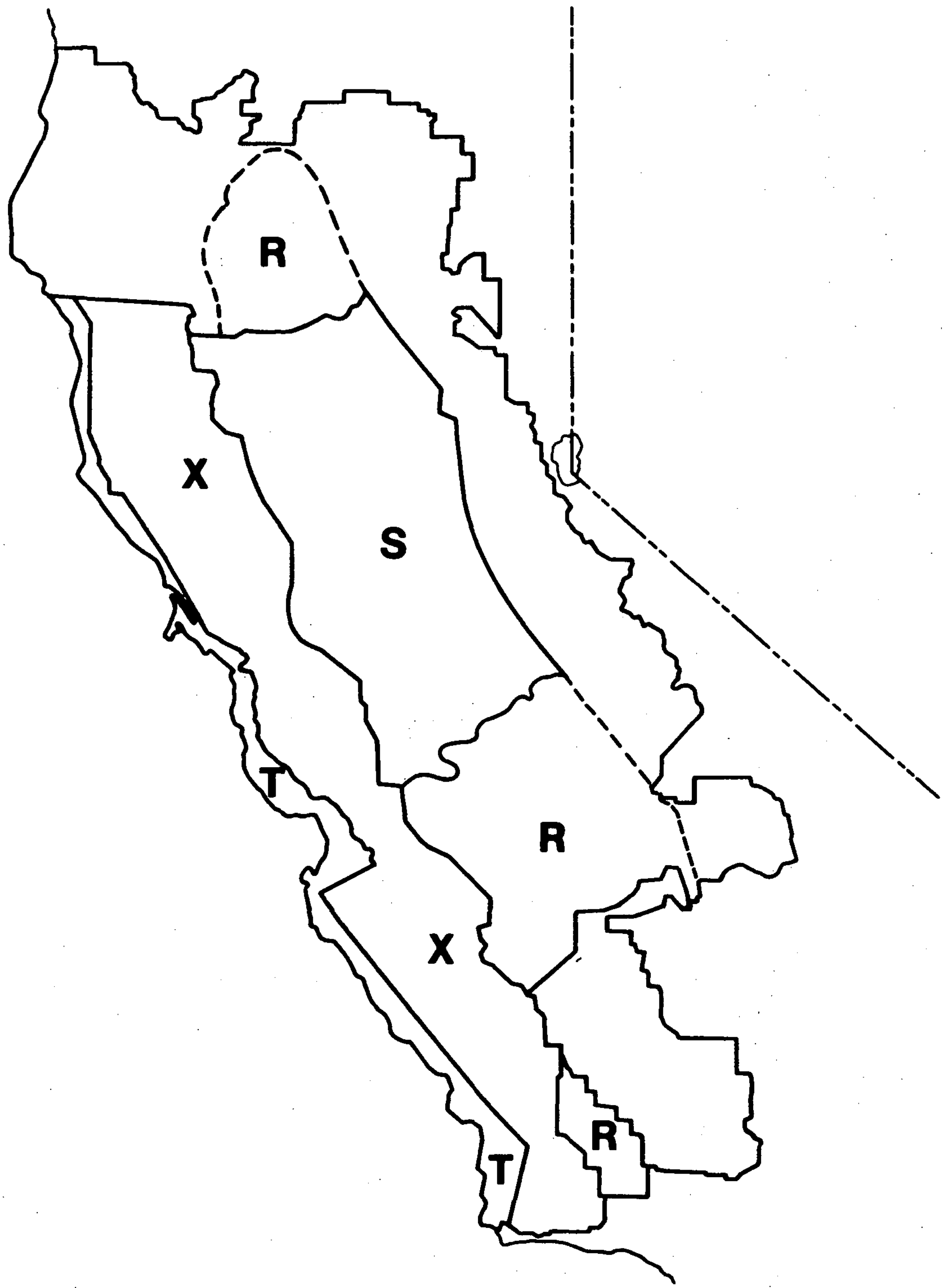


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Table 1. Policy Case Appliance Efficiencies

| Year | 1984 | 1988 | 1992 | 1996 | 2000 |
|---|---|---|---|---|---|
| Space Heating (AFUE)* | | | | | |
| electric | 100 | 100 | 100 | 100 | 100 |
| gas | 77 | 86 | 87 | 88 | 89 |
| oil | 86 | 91 | 91 | 91 | 91 |
| Air Conditioning | | | | | |
| room (EER) | 7.4 | 9.0 | 9.0 | 9.1 | 9.1 |
| central (SEER) | 7.0 | 8.5 | 8.6 | 8.7 | 8.8 |
| Water Heater (percent) | | | | | |
| electric | 82 | 93 | 93 | 93 | 93 |
| gas | 62 | 82 | 82 | 82 | 82 |
| Refrigerators ($ft^3$/kWh/d) | 7.1 | 11 | 11 | 11 | 11 |
| Freezers($ft^3$/kWh/d) | 13 | 22 | 22 | 22 | 22 |
| Ranges (percent) | | | | | |
| electric | 44 | 45 | 45 | 46 | 46 |
| gas | 26 | 32 | 34 | 35 | 35 |

* annual fuel use efficiency

## 3. Data Sources

As the output of the LBL Residential Energy Model is the primary input to the LBL Residential Hourly and Peak Demand Model, the bulk of this section is devoted to a review of the inputs to the first model. The presentation assumes some familiarity with the structure of the LBL Residential Energy Model. A complete description of the LBL Residential Energy Model can be found in Refs. 6 and 7.

The inputs to the LBL Residential Energy Model can be grouped into ten categories:

a. *Historic number of households by region.* The number of households in each region was an aggregation of historic PG&E customers into the current rate classes. That is, current PG&E rate classes represent consolidations of older rate classes.[9,10,11] Table 2 shows the historic number of customers by rate class.

**Table 2. PG&E Households by Region**

| Households (k) | 1981 | 1982 | 1983 |
|---|---|---|---|
| *TOTAL* | 3291.500 | 3373.600 | 3431.100 |
| Region *r* | 230.300 | 243.784 | 251.947 |
| Region *s* | 395.270 | 401.143 | 416.133 |
| Region *t* | 757.501 | 785.086 | 806.946 |
| Region *x* | 1085.403 | 1125.870 | 1152.022 |
| Other | 823.026 | 817.717 | 804.052 |

b. *Forecast number of households by region.* The total number of households in the PG&E service area (1984-2004) corresponds to the input assumptions used by the PG&E's residential forecasting model.[12] The number assigned to each region was this total (summing across all four housing types) weighted by the ratio of the average number of households in the region (from Refs. 9, 10, and 11, above) to the historic average total. Table 3 shows these fractions and Table 4 shows the total households.

**Table 3. Fractions of PG&E Households**

| Fraction | 1981 | 1982 | 1983 | Average |
|---|---|---|---|---|
| Region *r* | .069968 | .072262 | .073430 | .071887 |
| Region *s* | .120088 | .118907 | .121283 | .120093 |
| Region *t* | .230139 | .232715 | .235186 | .232680 |
| Region *x* | .329759 | .333730 | .335759 | .333083 |
| Other | .250046 | .242386 | .234342 | .242258 |

c. *Forecast additions to the housing stock by region.* The number of additions was based on the forecast number of households by region. Using 1982 as an example, we first calculated the difference in stocks in the PG&E service territory (1982 stock minus 1981 stock); this term is the increment in housing stock in this region for a single year. The total number of additions (from Ref. 12) minus the regional increments is the total number of replaced households. That is, replacement means a new house is constructed in place of one that is torn down, with no net change in the total number of households. Next, we assumed the number of houses replaced to be proportional to the housing stock. The number of replacements in a region is, thus, the fraction of the stock in the region multiplied by the total replacements. Appendix A contains a detailed

**Table 4. PG&E Households 1984-2000**

| Year | Households (k) |
|---|---|
| 1984 | 3492.8 |
| 1985 | 3559.3 |
| 1986 | 3623.9 |
| 1987 | 3687.3 |
| 1988 | 3748.4 |
| 1989 | 3802.7 |
| 1990 | 3861.8 |
| 1991 | 3924.1 |
| 1992 | 3998.5 |
| 1993 | 4072.3 |
| 1994 | 4150.1 |
| 1995 | 4230.5 |
| 1996 | 4316.6 |
| 1997 | 4402.5 |
| 1998 | 4489.8 |
| 1999 | 4577.1 |
| 2000 | 4665.6 |

example.

d. *Appliance holdings and vintages in 1981.* The saturations of most non-weather sensitive appliances were taken from a PG&E survey[13] which distinguishes these saturations by housing type, not region. We weighted and aggregated these saturations across housing types for each region (see Table 5).

For central air conditioning, the correspondence of California Energy Commission forecasting regions with LBL regions (see Table 6) allowed us to assign region-specific saturations.[14] Information disaggregated to this level was not available for the saturation of room air conditioning by region; we assumed that it was constant across all regions.

The saturations of electric space heating were taken from the rate class data in Refs. 9, 10, and 11. Customers with electric space heating are billed on a different rate schedule than those with non-electric space heating.

For the saturation of water heating by fuel type, we made assumptions that linked the choice of space heating fuel to the choice of water heating fuel. Briefly, all customers with electric space heating were assumed to have electric water heating, but some customers with non-electric space heating were assumed to have electric water heating. The discussion of the initialization process in the next section and Appendix B contain additional details.

We assumed the vintages of the initial stock of appliance to be the same as the age distribution of appliances sold nationally. For central air conditioners in one region, we used an arbitrary history of purchases to reconcile differences between 1981 purchases and saturations, and the saturations implied by the national age distribution.

e. *Marginal saturation of appliances.* The marginal saturations take their starting point with the 1981 values used by PG&E's model.[12] For subsequent years, they are calculated by the LBL Model's Market Shares algorithm (not held constant, as in Ref. 12). Table 7 shows the resulting marginal saturations.

f. *Unit energy consumption of 1981 appliance stock.* We adopted the Unit Energy Consumption (UEC) estimates used by PG&E's model, but adjusted them for each rate class (see Table 8). There are, however, definitional mismatches for the miscellaneous category. The LBL

**Table 5. 1981 Appliance Saturations (fraction of households)**

| | | R | S | T | X | Z |
|---|---|---|---|---|---|---|
| Space heat | Electric | .149 | .199 | .106 | .113 | .078 |
| | Gas | .708 | .452 | .792 | .759 | .726 |
| | Other | .142 | .339 | .092 | .118 | .186 |
| | None | .010 | .010 | .010 | .010 | .010 |
| Air conditioner | Central | .382 | .248 | .021 | .162 | .225 |
| | Room | .089 | for all regions | | | |
| Water heater | Electric | .082 | .131 | .070 | .074 | .051 |
| | Gas | .733 | .468 | .820 | .785 | .751 |
| | None | .185 | .401 | .110 | .140 | .198 |
| Refrigerator | | 1.18 | | for all regions | | |
| Freezer | | .33 | | " " " | | |
| Cooking | Electric | .562 | | " " " | | |
| | Gas | .402 | | " " " | | |
| | None | .036 | | " " " | | |
| Dryer | Electric | .458 | | " " " | | |
| | Gas | .140 | | " " " | | |
| | None | .402 | | " " " | | |
| Miscellaneous | Electric | .5 | | " " " | | |
| | Gas | .5 | | " " " | | |

**Table 6. Comparison of definitions of weather regions**

| LBL | | PG&E | | |
|---|---|---|---|---|
| Weather station | Region | Summer | Winter | CEC |
| Fresno | R | A | X | 3 |
| Stockton | S | B | X | 1,2 |
| Oakland | T | N | T | 5 |
| San Jose | X | C | X | 4 |

miscellaneous category for end-uses includes the following PG&E categories:

- For electric end-uses: dishwashers, clotheswashers, pool pumps, and miscellaneous.
- For natural gas end-uses: pool heaters and miscellaneous.

g. *Marginal unit energy consumption of new appliances.* The marginal unit energy consumption corresponds to that of the technology making the greatest penetration into the market (most rapid growth in saturation) according to Ref. 12 for 1981-82. We note that direct translation of these quantities from PG&E data may suffer from an aggregation bias. For example, in the case of gas cooking, the LBL data base seems to represent an average of a large number of designs, with a lower average efficiency than those of PG&E.[8] We attempted to correct for these incongruences by using estimates of the marginal UEC's of the PG&E technology options, expressed relative to LBL reference appliances (see Table 9).

h. *Economic drivers: electricity price, natural gas price, and income forecasts.* Electricity rates were derived at LBL for the financial impact calculations. The details are discussed in Section III, under Revenues. Natural gas rates came from Ref. 12 (see Table 10); other fuels were assumed to track natural gas.

**Table 7. 1981 Marginal Appliance Saturations (fraction of households)**

| | | R | S | T | X | Z |
|---|---|---|---|---|---|---|
| Space heat | Electric | .161 | .276 | .266 | .118 | .200 |
| | Gas | .683 | .397 | .694 | .845 | .700 |
| | Other | .129 | .326 | .039 | .036 | .090 |
| | None | .027 | .001 | .001 | .001 | .010 |
| Air conditioner | Central | .660 | .439 | .080 | .475 | .371 |
| | Room | .093 | for all regions | | | |
| Water heater | Electric | .142 | .237 | .229 | .100 | .171 |
| | Gas | .723 | .426 | .745 | .900 | .751 |
| | None | .135 | .337 | .026 | .000 | .078 |
| Refrigerator | | 1.15 | | for all regions | | |
| Freezer | | .325 | | " " " | | |
| Cooking | Electric | .796 | | " " " | | |
| | Gas | .168 | | " " " | | |
| | None | .036 | | " " " | | |
| Dryer | Electric | .600 | | " " " | | |
| | Gas | .093 | | " " " | | |
| | None | .307 | | " " " | | |
| Miscellaneous | Electric | .5 | | " " " | | |
| | Gas | .5 | | " " " | | |

**Table 8. 1981 Appliance Unit Energy Consumption**
(million Btu/year, where 11500 Btu = 1 kwh)

| | | R | S | T | X | Z |
|---|---|---|---|---|---|---|
| Space heat | Electric | 36.43 | 37.0 | 26.39 | 43.04 | 41.81 |
| | Gas/other | 46.87 | 49.87 | 45.52 | 50.05 | 45.96 |
| Air conditioner | Central | 20.88 | 14.77 | 0.35 | 11.93 | 20.24 |
| | Room | 5.48 | | for all regions | | |
| Water heater | Electric | 44.60 | | " " " | | |
| | Gas | 21.17 | | " " " | | |
| Refrigerator | | 13.12 | | " " " | | |
| Freezer | | 13.62 | | " " " | | |
| Cooking | Electric | 8.56 | | " " " | | |
| | Gas | 4.58 | | " " " | | |
| Dryer | Electric | 10.58 | | " " " | | |
| | Gas | 2.66 | | " " " | | |
| Miscellaneous | Electric | 87.85 | 83.94 | 26.09 | 53.75 | 47.27 |
| | Gas | 1.22 | for all regions | | | |

Income was calculated by aggregating county (or sub-county) projections by the Center for the Continuing Study of the California Economy[15] to the four regions.

i. *Thermal integrity of housing.* The relative UEC's for space conditioning of new buildings to those of the existing stock were used as estimates of the thermal integrity factors. The initial UEC's are generated by LBL using DOE-2 model runs of typical existing and new residential structures in different California climates.[16] Since the boundaries of the rate classes correspond to climatic regions in the state, we were able to use local weather data. Weather data for "typical years" in Fresno, Stockton, Oakland, and San Jose were used to represent conditions in regions,

**Table 9. Relative unit energy consumption**
(PG&E new unit compared to LBL reference)

| | | |
|---|---|---|
| Space heat | Electric | exogenous in LBL model |
| | Gas/other | .913 |
| Air conditioner | Central | .831 |
| | Room | .764 |
| Water heater | Electric | .856 |
| | Gas | .789 |
| Refrigerator | | .598 |
| Freezer | | .776 |
| Cooking | Electric | .877 |
| | Gas | .8 |
| Dryer | Electric | .991 |
| | Gas | 1.0 |
| Miscellaneous | Electric | 1.0 |
| | Gas | 1.0 |

**Table 10. PG&E Residential Gas Prices**

| Year | Price (1967 dollars/MBtu) |
|---|---|
| 1981 | 1.352 |
| 1982 | 1.414 |
| 1983 | 1.681 |
| 1984 | 1.635 |
| 1985 | 1.799 |
| 1986 | 1.834 |
| 1987 | 1.969 |
| 1988 | 2.322 |
| 1989 | 2.418 |
| 1990 | 2.417 |
| 1991 | 2.322 |
| 1992 | 2.360 |
| 1993 | 2.342 |
| 1994 | 2.341 |
| 1995 | 2.375 |
| 1996 | 2.483 |
| 1997 | 2.473 |
| 1998 | 2.530 |
| 1999 | 2.566 |
| 2000 | 2.604 |

R, S, T, and X, respectively.

For the first year (1981), DOE-2 predicts factors of 0.609 for electric space heat, 0.920 for natural gas space heat, and 0.714 for room and central air conditioning. Again, a detailed comparison of PG&E and LBL data bases on housing characteristics may yield a more accurate estimate of these initial values.

j. *Default values.* The following values were taken from the LBL default library (see Ref. 4):

- Engineering cost relationship for the technologies.
- Thermal integrity cost relationships.
- Market share elasticities.
- Usage elasticities.
- Floor area per household.
- Number of retrofits.
- Appliance lifetimes.
- Equipment costs.
- Appliance retirement functions.

The inputs to the LBL Residential Hourly Load and Energy Demand Model are the annual forecasts of electricity consumption by end-use produced by the LBL Residential Energy Model and a one year record of hourly dry-bulb temperatures. The weather data used to produce the DOE-2 building energy use simulation estimates for space-conditioning thermal integrity factors were used to spread the annual forecasts over the hours of the year.

## 4. Model Calibration

The models were calibrated by comparing forecasts generated based on historic data to actual recorded sales and load profiles for the years 1981-1983. To a lesser extent, the intermediate outputs of the Energy Model, particularly marginal saturations and UEC's, were also scrutinized and modified as necessary. Repetition of this process allowed us to "tune" the model inputs to match history.

In this section, we review four important features of the calibration process for PG&E:

- The definition of customer classes.
- The calibration for electric and gas appliance saturations.
- The revisions made to the time/temperature matrix for cooling space conditioning.
- The use of the miscellaneous category of end-use and the corresponding load profile.

*Customer class definition.* The first step in tuning the LBL Residential Energy Model was to distinguish between the two rate classes within each region. The reader will recall that the rate classes are defined by the space heating fuel used: H = electric space heating present; B = electric space heating absent.

The LBL Residential Energy Model was developed to model residential energy use by geographic regions, but does not distinguish appliance holdings by households. Within a region, the choice of space heating fuel is calculated endogenously. Hence, the fraction of the population with electric space heating, which puts those customers on a different PG&E rate schedule, changes over time. At the same time, the model projects energy consumed by other end-uses for the total population, which is undifferentiated with respect to space heating fuel choice. For the purpose of allocating total sales for all other end-uses to a rate class, we needed to first identify those customers with electric space heat and then separately quantify their consumption of electricity for other end-uses.

Our resolution of this problem was to run the model iteratively. The first run was used to identify the stock of households in each rate class based on the saturation of electric space heating. For the production runs, two separate runs were required (one for each class). One held the saturation of gas appliances at zero for the electric space heating customers (class H), while the other held the saturation of electric space heating at zero (class B).

We also developed several rules for modifying the other inputs required for the two production runs. These generally consisted of holding saturations and UEC's fixed across the two classes for electric-only end-uses (e.g. refrigerators) and, for the saturation of other appliances, linking the fuel choices for water heating, cooking, and dryers to the space heating fuel. Appendix B contains a detailed description of these rules and the resulting values used for each rate class. One exception to these general rules was the miscellaneous category. We used the UEC of this end-use as the final tuning for obtaining agreement with the 1981-83 historic sales. Where tuning of miscellaneous sales was unable to produce agreement with recorded sales by rate class, however, we questioned other assumptions. In the case of weather zone X, for example, agreement could only be obtained by reducing the UEC for space heating.

A final complication arose from the definitions of the rate classes, themselves. The rate classes we examined are the result of a recent consolidation of several older rate classes. Thus, historic sales had to be aggregated to correspond with the new rate classes in order to make the sales comparisons. Tables 11, 12, and 13 contain our aggregations for PG&E sales by rate class for 1981-83. Where rate class boundaries were redefined, however, history serves as no guide. In fact, such a redefinition took place with the predecessors to rate classes T and X in May 1981.

**Table 11. PG&E Residential Sales - 1981**

| Rate Class | # Bills (Millions) | Sales (TWh) | # Customers (Thousands) | Average Bill (kWh) | % Sales | % Bills |
|---|---|---|---|---|---|---|
| RBS | 1.209 | 0.852 | 201.541 | 704 | 4.84 | 3.61 |
| RBW | 1.001 | 0.527 | 166.803 | 526 | 3.00 | 2.99 |
| RHS | 0.173 | 0.174 | 28.759 | 1007 | 0.99 | 0.52 |
| RHW | 0.142 | 0.160 | 23.592 | 1133 | 0.91 | 0.42 |
| SBS | 1.899 | 1.156 | 316.426 | 609 | 6.57 | 5.67 |
| SBW | 1.544 | 0.811 | 257.337 | 525 | 4.61 | 4.61 |
| SHS | 0.473 | 0.447 | 78.844 | 946 | 2.54 | 1.41 |
| SHW | 0.416 | 0.518 | 69.259 | 1246 | 2.94 | 1.24 |
| TBS | 4.062 | 1.264 | 677.017 | 311 | 7.19 | 12.13 |
| TBW | 4.010 | 1.438 | 668.293 | 359 | 8.17 | 11.97 |
| THS | 0.483 | 0.231 | 80.484 | 477 | 1.31 | 1.44 |
| THW | 0.477 | 0.230 | 79.433 | 482 | 1.31 | 1.42 |
| XBS | 5.779 | 2.696 | 963.152 | 466 | 15.32 | 17.25 |
| XBW | 9.070 | 4.067 | 1511.617 | 448 | 23.12 | 27.08 |
| XHS | 0.734 | 0.355 | 122.251 | 484 | 2.02 | 2.19 |
| XHW | 1.124 | 0.834 | 187.302 | 742 | 4.74 | 3.36 |
| *TOTAL* | 32.593 | 15.758 | 2716.055 | 483 | 89.59 | 97.32 |

**Table 12. PG&E Residential Sales - 1982**

| Rate Class | # Bills (Millions) | Sales (TWh) | # Customers (Thousands) | Average Bill (kWh) | % Sales | % Bills |
|---|---|---|---|---|---|---|
| RBS | 1.242 | 0.725 | 206.968 | 584 | 4.22 | 3.66 |
| RBW | 1.252 | 0.631 | 208.707 | 504 | 3.68 | 3.69 |
| RHS | 0.221 | 0.186 | 36.816 | 841 | 1.08 | 0.65 |
| RHW | 0.217 | 0.240 | 36.242 | 1104 | 1.40 | 0.64 |
| SBS | 1.914 | 0.984 | 318.938 | 514 | 5.73 | 5.64 |
| SBW | 1.916 | 0.958 | 319.271 | 500 | 5.58 | 5.65 |
| SHS | 0.493 | 0.392 | 82.205 | 795 | 2.28 | 1.45 |
| SHW | 0.489 | 0.568 | 81.460 | 1162 | 3.31 | 1.44 |
| TBS | 4.019 | 1.217 | 669.833 | 303 | 7.09 | 11.84 |
| TBW | 4.028 | 1.418 | 671.381 | 352 | 8.26 | 11.87 |
| XBS | 5.992 | 2.580 | 998.694 | 431 | 15.03 | 17.66 |
| XBW | 5.867 | 2.926 | 977.773 | 499 | 17.05 | 17.29 |
| XHS | 0.763 | 0.349 | 127.176 | 457 | 2.03 | 2.25 |
| XHW | 0.760 | 0.581 | 126.664 | 765 | 3.38 | 2.24 |
| *TOTAL* | 30.212 | 14.332 | 2517.660 | 474 | 83.47 | 89.03 |

**Table 13. PG&E Residential Sales - 1983**

| Rate Class | # Bills (Millions) | Sales (TWh) | # Customers (Thousands) | Average Bill (kWh) | % Sales | % Bills |
|---|---|---|---|---|---|---|
| RBS | 1.281 | 0.820 | 213.519 | 640 | 4.64 | 3.69 |
| RBW | 1.283 | 0.652 | 213.838 | 508 | 3.69 | 3.69 |
| RHS | 0.231 | 0.214 | 38.428 | 929 | 1.21 | 0.66 |
| RHW | 0.231 | 0.252 | 38.473 | 1091 | 1.43 | 0.66 |
| SBS | 1.966 | 1.117 | 327.711 | 568 | 6.32 | 5.66 |
| SBW | 1.985 | 1.004 | 330.862 | 506 | 5.69 | 5.72 |
| SHS | 0.531 | 0.467 | 88.422 | 881 | 2.65 | 1.53 |
| SHW | 0.523 | 0.596 | 87.092 | 1141 | 3.38 | 1.50 |
| TBS | 4.297 | 1.371 | 716.151 | 319 | 7.76 | 12.37 |
| TBW | 4.288 | 1.551 | 714.680 | 362 | 8.78 | 12.35 |
| THS | 0.545 | 0.244 | 90.795 | 448 | 1.38 | 1.57 |
| THW | 0.546 | 0.359 | 90.940 | 658 | 2.03 | 1.57 |
| XBS | 6.124 | 2.839 | 1020.657 | 464 | 16.07 | 17.63 |
| XBW | 6.000 | 3.005 | 999.979 | 501 | 17.01 | 17.28 |
| XHS | 0.788 | 0.399 | 131.365 | 506 | 2.26 | 2.27 |
| XHW | 0.777 | 0.591 | 129.540 | 760 | 3.34 | 2.24 |
| *TOTAL* | 31.395 | 15.481 | 2616.227 | 493 | 87.64 | 90.40 |

*Electric and gas appliance saturations.* The trial runs for region R produced anomalous forecasts for the marginal saturation of electric space heaters (too low) and electric cooking (too high). We concluded that these odd fuel choices were manifestations of a single phenomenon.

The model first expresses the efficiency of an appliance in terms of a first cost via a technology curve of engineering estimates of performance potentials versus cost. Then, given a projection of fuel prices, the model projects a penetration for the appliance and, ultimately, an annual energy consumption figure for the end-use.

For cooking, the efficiency of new units (gas and electric) was determined by the outputs of PG&E's own forecasting model.[17] The placement of these efficiencies on the technology cost curve resulted in a very high first cost for gas cooking appliances. Subsequently, when the model predicted fuel choice, the market shares were biased toward electric cooking appliances.

For electric space heating, the first cost was also the driving force for the choice of fuel. The first cost of heat pumps is substantially higher than that for resistance electric and gas furnaces. At the same time, the cost of electric space heating appliances is not explicitly differentiated between resistance- and heat pump-driven electric space heat. Instead, the model represents the cost of electric space heating by a composite appliance that weights the first cost by an assumed mix of heat pump and resistance heater sales. Since the majority of new electric space heating installations are heat pumps (based on national survey data), the first cost of the average new electric space heater is much higher than the average new gas heater. In this situation, the model forecasts declining electric space heating relative to gas furnaces.

The long-term solution for cooking is either a more careful mapping of the technologies in the PG&E data base to the technology cost curves in the LBL model, or the derivation of new technology cost curves consistent with the PG&E data base. For space heating, we believe there is a need for an explicit disaggregation of resistance from heat pump electric heating appliances. Our interim solution for these end-uses was to redefine the marginal efficiency of cooking appliances at a lower value, which avoids driving the first cost too high. For electric space heating, we assumed a lower penetration for heat pumps relative to conventional electric space heating appliances, rather than assign lower efficiencies to heat pumps.

*Central air conditioning time/temperature matrix.* For weather-sensitive end-uses, the data base of the LBL Hourly and Peak Demand Model contains empirical measurements of the response of the end-use to temperature as a function of the type (weekday vs. weekend, summer vs. winter) and time of day. The model uses these measurements as weights for hourly energy consumption by the end-use, given the type and time of day, and temperature contained in a weather data tape. These weights are then normalized and used to distribute the projected electricity consumed by the end-use to every hour in the year. Finally, the hourly electricity demands by end-use are summed to yield a diversified load for the class.

When we first began to compare the critical summer load shapes generated by the model with load data provided by PG&E,[18, 19] we noted an odd flatness in the summer peak day load shapes. On the summer peak day, for example, load would rise in step with temperature, as expected, and reach a maximum value around 3 p.m. (see Figure 2). This level would be maintained, in the face of increasing temperature, until about 10 p.m., when it would begin to decline with temperature. The PG&E load data indicated that the maximum value was not generally reached until 7 p.m. and that this maximum was higher and far more steeply peaked than our model indicated. Also, the baseload demand, which our results indicated contained a large cooling component, was much higher than indicated by the load data.

We resolved these inconsistencies by re-evaluating the empirical data base of the model with other PG&E load data. We obtained hourly, diversified load data for the hot Fresno and Stockton regions from a monitoring project of the PG&E Load Research Group.[20] We also located hourly temperatures corresponding to days selected in the study from the weather stations at the Fresno and Stockton airports.

Figure 2. Comparison of summer peak day load shapes - PG&E recorded vs. LBL unadjusted.

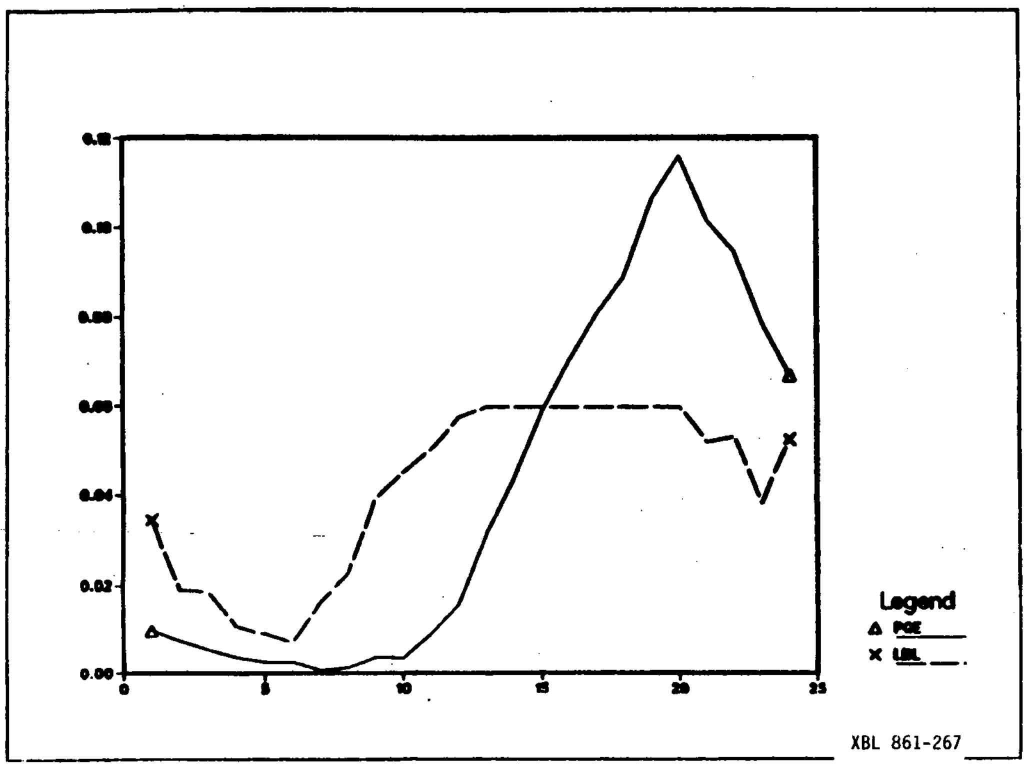
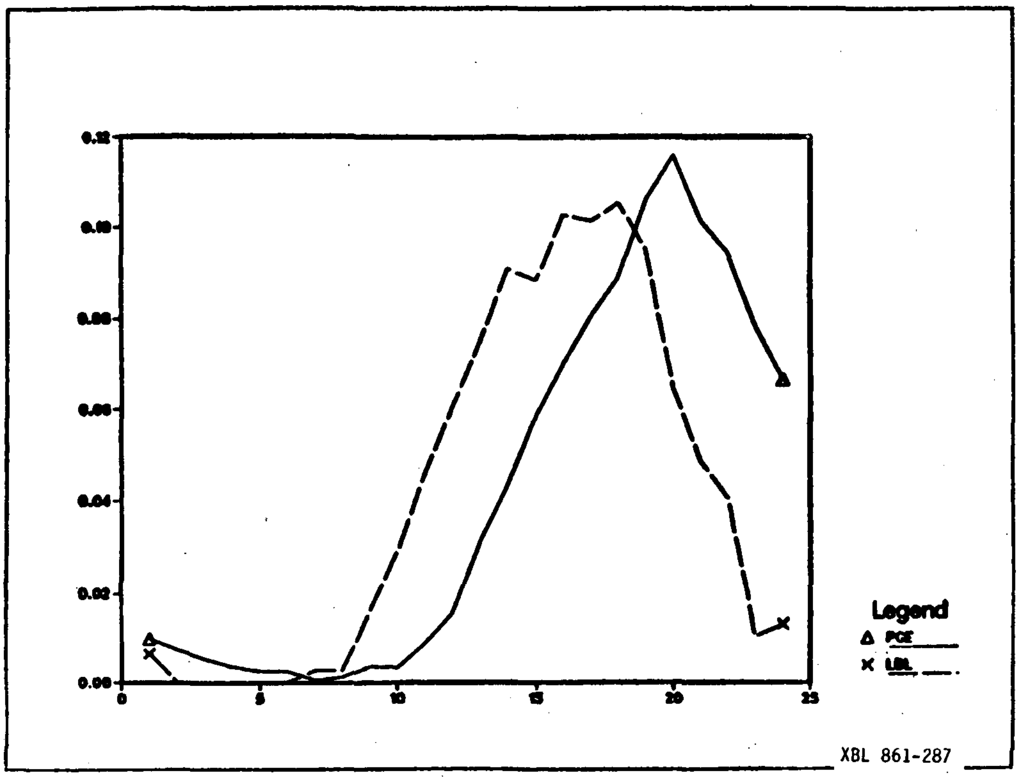


Figure 3. Comparison of summer peak day load shapes - PG&E recorded vs. LBL adjusted.




Hand calculations of the model's response to these temperatures confirmed our suspicion that the model's air conditioning response reached a maximum value at too low a temperature. By shifting the time/temperature matrix upward so that the peak was not reached at such low temperatures, we were able to approximate the monitored results much more closely. Figure 3 compares the monitored data to the model's modified response to temperature.

Figure 3 indicates that while the LBL model has succeeded in capturing the magnitude of PG&E's recorded peak, the issue of coincidence remains. The LBL model forecasts a peak demand approximately four hours earlier that recorded by PG&E. Reference to the data source for the LBL model may serve to explain the variance. The data for the LBL Residential Hourly and Peak Demand Model was derived from load data from a utility whose service area is more humid than PG&E's. The LBL time/temperature matrices do not currently incorporate humidity data (e.g. wet bulb temperature).

We were fortunate in finding such a simple interim fix to this problem. The experience suggests, however, that closer scrutiny of these and the other empirical correlations in the LBL Hourly Demand and Peak Load Model is warranted. This process may be facilitated by making further use of existing PG&E load studies.

*Miscellaneous end-use electricity consumption and load profile.* The miscellaneous category of electricity use and its load shape are also in need of additional study. The importance of this work is underscored by the substantial fraction of energy use represented by this category in our models. For PG&E, miscellaneous electricity sales accounted for up to 41 % of forecast sales (for the DECO study, the figure was nearly 30 %). The magnitude of sales for this end-use, however, compares favorably with PG&E predictions, which attribute 38 to 50 % of sales to this category.

Our preliminary attempts to match recorded sales showed good agreement for yearly totals, but systematic over-estimates of winter and under-estimates of summer sales. Since changes in one season must be offset in the other, we thought adjustments to the UECs of the thermal comfort appliances were the source of the mismatch. This hypothesis was contradicted by the absence of electric space heating in the class with the bulk of the sales and customers. Customers in Class B have no electric space heating, by definition.

Without space heating, the remaining candidate for adjustment is the miscellaneous category. The miscellaneous category is ill-defined, but is known to include televisions, clotheswashers, dishwashers, swimming pool pumps, and auxiliary power devices such as furnace fans for gas furnaces. Our experience with the data from the DECO study led us to weight the last appliance heavily, and so increase the winter portion of miscellaneous energy use over the summer. For PG&E, the DECO approach could not be applied directly because the direction of the mismatch was different and because California has a milder heating season. We also knew the composition of the miscellaneous category was different. Pool pumps are not a major concern in Detroit, but electric blankets are. Further, this composition may vary by region in PG&E; pool pumps may be concentrated in the warmer regions.

We began by making consistent adjustments to the distribution of miscellaneous electricity consumption between seasons. Unfortunately, the results were uneven between regions and, within regions, between rate classes. Closer agreement for the larger classes tended to be off-set slightly by additional small variance from recorded sales in the smaller classes. We concluded that additional research would prove most beneficial for this category of end-use.

## 5. Residential Energy Use and Peak Demand Forecasts for PG&E

For the initialization years, 1981-83, our results show good agreement with historic sales (within 10 %). Not surprisingly, we show even better agreement with the backcasts by the PG&E Model for those years.[12] That is, having relied on many of the same input assumptions, both end-use models generate similar results. Tables 14, 15, and 16 compare actual PG&E sales and LBL forecasts in aggregate and by rate class for these historic years. In examining these tables, it is important to remember that 1981 PG&E sales are for rate classes whose boundaries shifted during May. Also, LBL sales are based on the models' response to hypothesized, typical weather.

Figures 4 and 5 present the results of our model projections for residential class sales and peak demand from 1981 to 2000, respectively. Again, residential sales refer to the subset of PG&E's total residential class accounted for by the eight rate classes of this LBL study.

**Table 14. LBL Forecast (6/26) vs. PG&E Recorded Sales (TWH)**

Weather: PG&E = Actual LBL = Normal

| Region - Year | PG&E | LBL | Error (%) * |
|---|---|---|---|
| R - 1981 | 1.713 | 1.718 | .3 |
| R - 1982 | 1.782 | 1.816 | 1.9 |
| R - 1983 | 1.938 | 1.881 | -2.9 |
| S - 1981 | 2.932 | 3.039 | 3.6 |
| S - 1982 | 2.902 | 3.076 | 6.0 |
| S - 1983 | 3.184 | 3.185 | .0 |
| T - 1981 | 3.163 | 3.224 | 1.9 |
| T - 1982 | 3.212 | 3.319 | 3.3 |
| T - 1983 | 3.525 | 3.397 | -3.6 |
| X - 1981 | 7.952 | 6.399 | -19.5 |
| X - 1982 | 6.436 | 6.618 | 2.8 |
| X - 1983 | 6.834 | 6.766 | -1.0 |
| *Total - 1981* | 19.585 | 18.949 | -3.2 |
| *Total - 1982* | 19.131 | 19.378 | 1.3 |
| *Total - 1983* | 19.823 | 19.710 | - .6 |

* Error = ((LBL/PGE) - 1) × 100)

**Table 15. Rate Class B (Non-Electric Space Heating): LBL Forecast (6/27) vs. PG&E Recorded Sales**

Weather: PG&E = Actual LBL = Normal

| Region - Year | PG&E | LBL | Error (%) * |
|---|---|---|---|
| R - 1981 | 1.379 | 1.317 | -4.5 |
| R - 1982 | 1.356 | 1.391 | 2.6 |
| R - 1983 | 1.472 | 1.438 | -2.3 |
| S - 1981 | 1.967 | 2.070 | 5.2 |
| S - 1982 | 1.942 | 2.082 | 7.2 |
| S - 1983 | 2.121 | 2.129 | .4 |
| T - 1981 | 2.702 | 2.668 | -1.3 |
| T - 1982 | 2.635 | 2.696 | 2.3 |
| T - 1983 | 2.922 | 2.704 | -7.5 |
| X - 1981 | 6.763 | 5.425 | -19.8 |
| X - 1982 | 5.506 | 5.605 | 1.8 |
| X - 1983 | 5.844 | 5.722 | -2.1 |
| *Sum - 1981* | 12.811 | 11.480 | -10.4 |
| *Sum - 1982* | 11.439 | 11.774 | 2.9 |
| *Sum - 1983* | 12.359 | 11.993 | -3.0 |

**Table 16. Rate Class H (Electric Space Heating): LBL Forecast (6/27) vs. PG&E Recorded Sales**

Weather: PG&E = Actual LBL = Normal

| Region - Year | PG&E | LBL | Error (%) * |
|---|---|---|---|
| R - 1981 | .334 | .401 | 20.1 |
| R - 1982 | .426 | .425 | - .2 |
| R - 1983 | .466 | .443 | -4.9 |
| S - 1981 | .965 | .969 | .4 |
| S - 1982 | .960 | .994 | 3.5 |
| S - 1983 | 1.063 | 1.056 | - .7 |
| T - 1981 | .461 | .557 | 20.8 |
| T - 1982 | .577 | .622 | 7.8 |
| T - 1983 | .603 | .693 | 14.9 |
| X - 1981 | 1.189 | .974 | -18.1 |
| X - 1982 | .930 | 1.012 | 8.8 |
| X - 1983 | .990 | 1.044 | 5.5 |
| *Sum - 1981* | 2.949 | 2.901 | -1.6 |
| *Sum - 1982* | 2.893 | 3.053 | 5.5 |
| *Sum - 1983* | 3.122 | 3.236 | 3.7 |

Figure 4. LBL forecast of PG&E residential class sales.

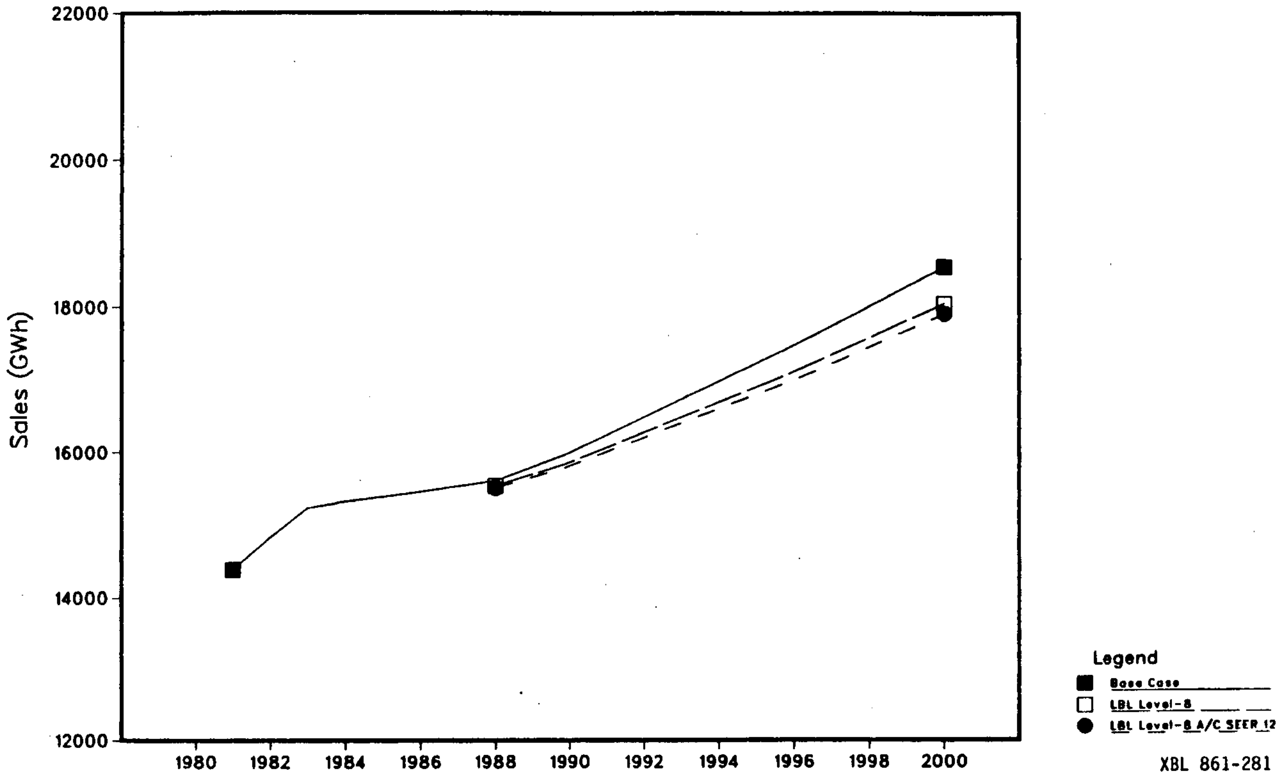
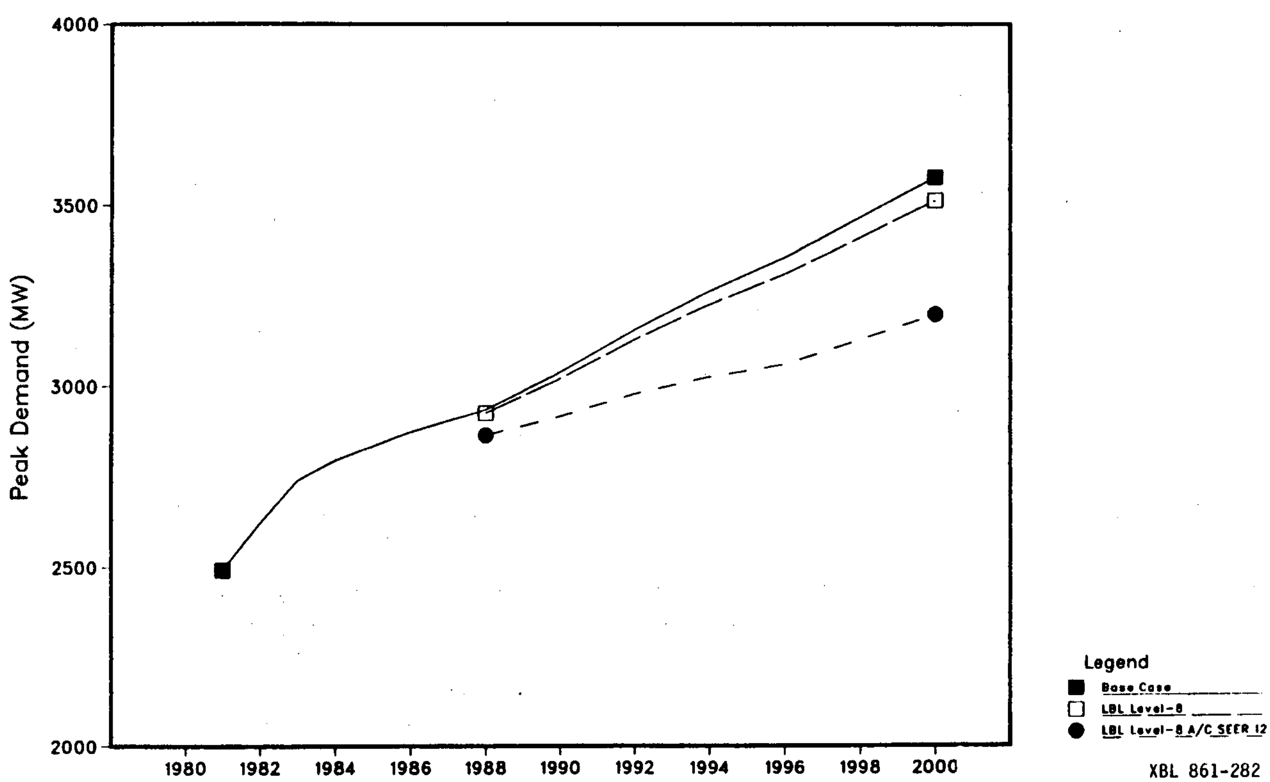



Figure 5. LBL forecast of PG&E residential class peak demands.



Since the available projections of residential sales and peaks do not distinguish between individual rate classes, we compare growth rates for the entire residential class. Projecting our base case into the future results in an average growth rate in residential sales of 1.2 %/yr. between 1984 and 2000. This growth rate is close to the 1980-2002 forecast of the California Energy Commission (CEC) for PG&E's residential class of 1.7 %/yr.[21] Our projected growth rate, however, falls well short of PG&E's projected growth rate of 2.3 %/yr. for all individually-metered residential sales between 1984-2000.[17]

To isolate the source of variance between PG&E's and LBL's forecast growth rate, we examined the implied forecast sales per customer (see Figure 6). Since our forecasts are in agreement for the historic years, we first conclude that the differences in absolute levels of sales result from higher than average sales to the sectors of PG&E's residential class that were omitted from the LBL study. Of more importance is the upturn in sales per customer predicted by the PG&E model for the final years in the forecast. The LBL model predicts gradually decreasing sales over the same period.

We hypothesize that the cause of this divergence may be attributed to sales accounted for by the mysterious miscellaneous category of end-use. Figure 7 confirms this hypothesis by comparing the LBL and PG&E forecasts of the percent of total sales to the miscellaneous category (the PG&E percentages include all the categories included in the LBL miscellaneous category). The LBL model predicts fairly constant fractions for the category of 40 %, while PG&E forecasts increasing fractions from 38 % to over 50 % by 2004.

With respect to peak demand, we forecast an average growth for the class of 1.6 %/yr. Again, by way of comparison, CEC forecasts peak demand growth of 1.8 %/yr. for PG&E's residential class from 1980-2002.[21] PG&E does not forecast either coincident or non-coincident peak demands for the residential class.

Turning now to the effects of the policy cases, the LBL Level-8 appliance standards introduced in 1987 reduce the average sales growth rate between 1986 and 2000 from 1.3 %/yr. to 1.0 %/yr. Similarly, peak demand growth is reduced from 1.6 %/yr to 1.5 %/yr. As expected, the prior existence of appliance standards in California has the effect of diminishing the impact of the LBL standards. For DECO the percentage change in sales from the base case in 1996 is 4.0 %[2] while for PG&E the corresponding change in 1996 is 2.1 %.

For the technology-forcing air conditioning version of the LBL Level-8 standards, much more dramatic peak demand reductions are accompanied by small additional sales reductions. Peak demand for the class increases at only 0.8 %/yr from 1986-2000, while sales grow at 1.1 %/yr. In terms of a percentage change from the base case in 1996, the demand is reduced by 8.8 % or nearly 300 MW compared to only 1.4 % in the Level-8 standard. By comparison, sales decline by 2.7 % versus 2.1 % in the Level-8 only standard in the same year.

The effect of the standards on individual end-uses can be seen by examining the percentage change in sales on a monthly basis for the two policy cases in 1996 (see Figure 8). The Level-8 standard appears to have little effect on heating end-uses. Rather, the effect is uniformly distributed throughout the year with some peaking during the summer. These summer savings are most likely due to the modest increases in air conditioning efficiency contained in the standard. As expected, the results for the second policy case, which includes a technology-forcing air conditioning standard, are identical during the winter months (when there is no significant need for air conditioning). During the summer months, however, the savings are nearly twice the Level-8 savings.

Figure 6. Comparison of PG&E and LBL forecasts of residential sales per customer.

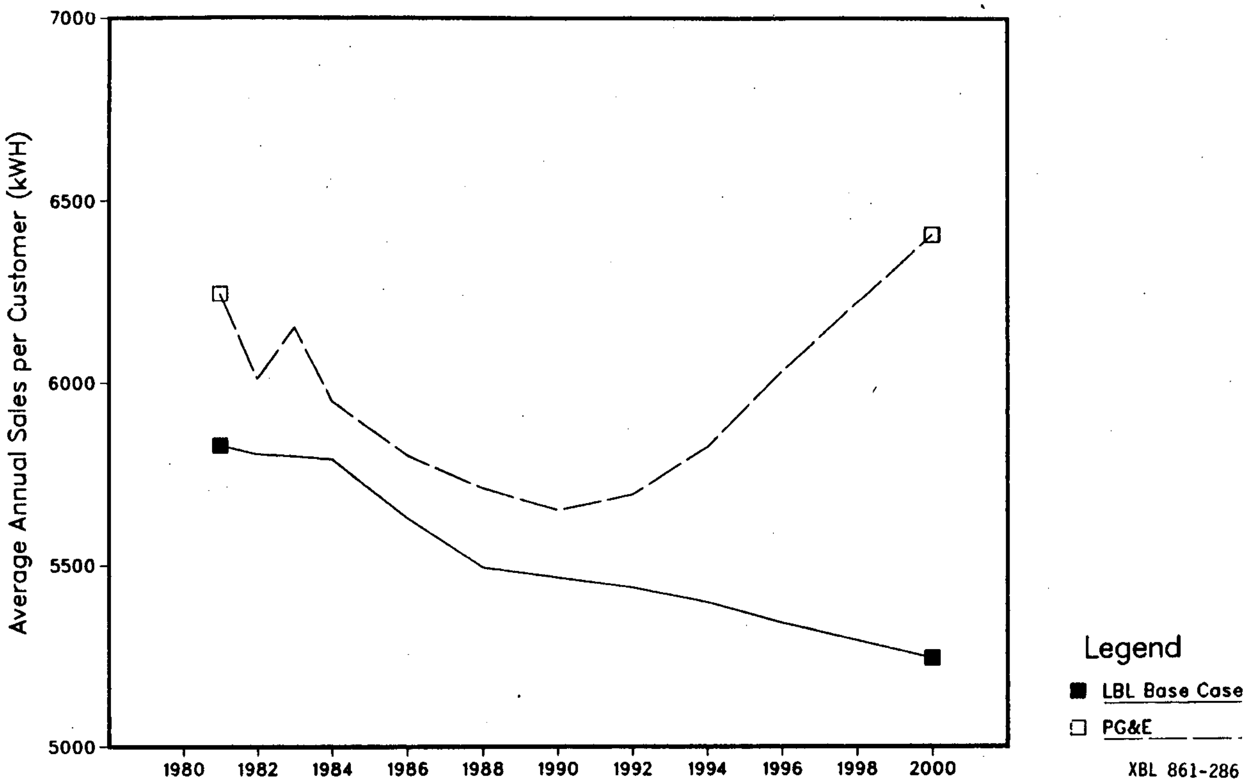



Figure 7. Comparison of PG&E and LBL forecasts of residential sales per customer for the miscellaneous class of end-uses.

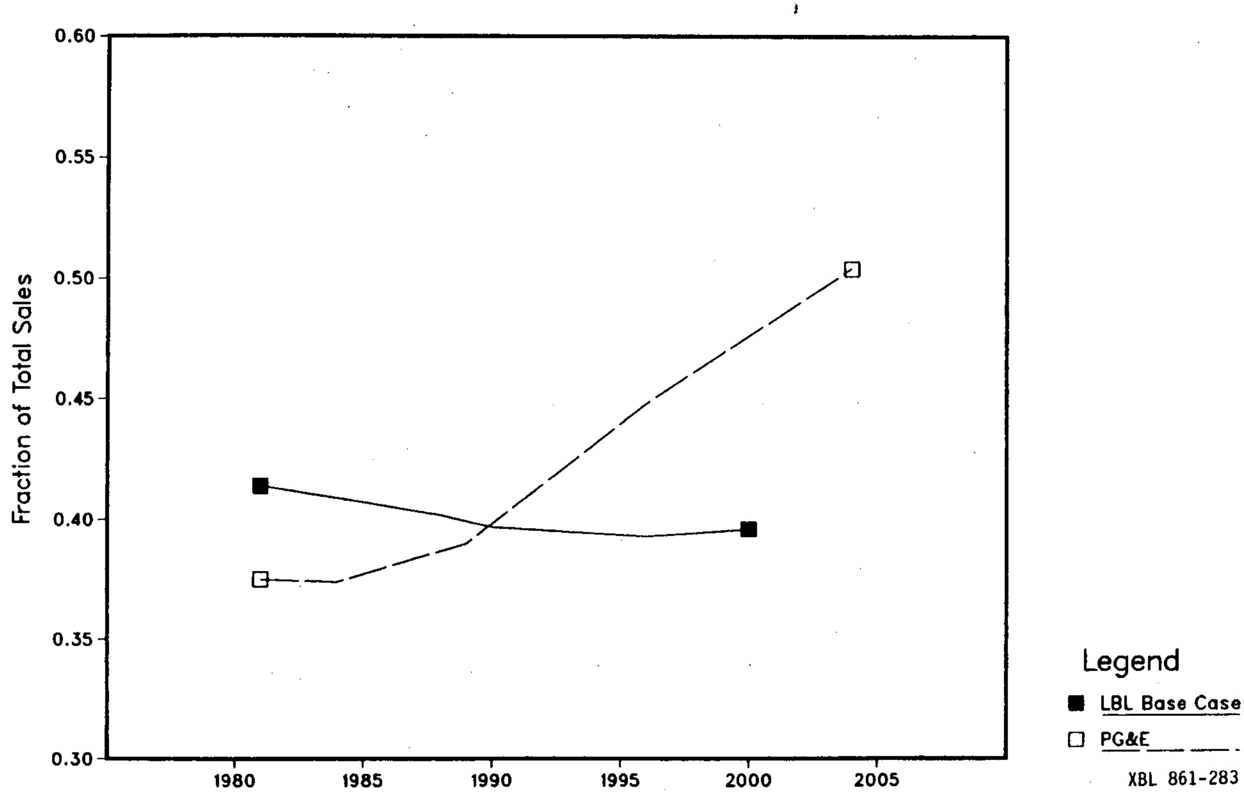
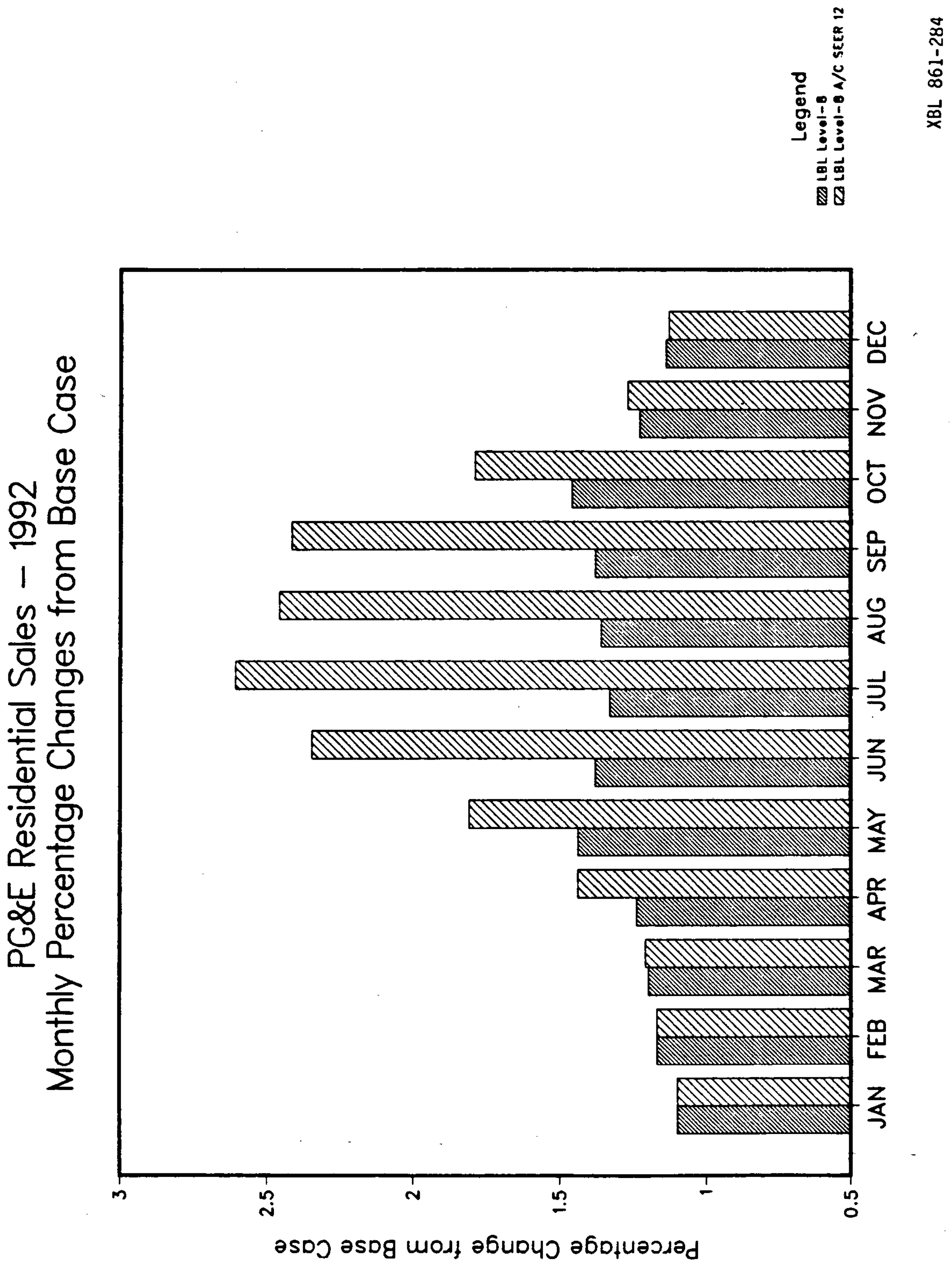


Figure 8. Monthly percentage changes in sales for the LBL policy cases.



# III FINANCIAL IMPACTS OF LOAD SHAPE CHANGES

## 1. Introduction

The bottom-line for the load shape changes described in the previous section is the financial impact on the stockholders of PG&E. We describe and motivate the methods for calculating financial impacts in our summary document.[1] The purpose of this section is to provide additional background on the methods, document data sources, and summarize intermediate findings.

We evaluate three components to determine the financial impacts of load shape changes stemming from policies to increase the efficiency of residential appliances:

- The changes in revenues due to decreased electricity sales.
- The avoided fuel or purchases of electricity resulting from reduced electricity production.
- A capacity credit for reliability benefits conferred by reduced electrical demands during peak periods for the system.

The first two, revenue changes and avoided production costs, are hypothetical for this utility. Regulatory policy in California is unique in that forecasting risks are not borne by the utility. The Electric Revenue Adjustment Mechanism (ERAM) ensures that revenue requirements will be met without regard to mismatches between actual and forecast sales. Hence, under-forecasts, resulting from an exogenous load shape change, do not affect the earnings of this utility. We, nevertheless, calculated this quantity to illustrate an effect that would show up on the balance sheet, in the absence of this regulatory policy. Economists might term this change in the operating margin the "value" of ERAM to PG&E stockholders.

The Pacific Gas and Electric Company does not enjoy the comfortable reserve margin that characterizes the Detroit Edison Company. Reductions in electricity demand during times of system peaks, consequently, have value beyond fuel savings in the form of reliability benefits. These benefits are, in fact, the only financial impact that would affect PG&E earnings, given the existence of ERAM. Therefore, load shape changes that reduce system peak loads will always have a positive impact on earnings.

In calculating the financial impacts for PG&E, we introduced a crude model of regulatory response to the policy-induced load shape change. This model bounds the regulatory response by limiting the changes in operating margin to four and eight years. That is, we hypothesize four to eight years must pass after the introduction of appliance standards before the operating margin changes can be identified and reconciled through the regulatory process. We note, however, that capacity benefits continue to accrue beyond this period due to the life of the appliances.

In fact, not only will efficient appliances "live" beyond the four to eight year regulatory lag, they will also continue to be sold after operating margin changes are reconciled. Our earlier hypothesis that appliance standards only temporarily increase the penetration of efficient appliances is one way of limiting these benefits. That is, until the efficiency of new appliances in the policy cases is attained by appliances in the base case, a capacity benefit for the stockholders will continue to result from the policy case. Under this view, the efficiency of new appliances in the base case will eventually "catch up" to those in the policy cases.

Finally, we wish to stress that, in calculating the value of each of these components, we have utilized a stylized representation of the utility for our analyses. We recognize that many of the assumptions used to complete this characterization are not endorsed by the Company. Examples of where better information would be of particular value include the specific rate levels at each tier in a tariff and further disaggregation, by time of day/season, of the marginal cost structure and of the distribution of Loss of Load Probabilities.

**2. Revenues**

Selling less electricity, as a result of policies that modify the utility's load shape, means that revenues are reduced from what they would have been. In the absence of ERAM, these changes in revenues represent a cost to shareholders of the policy-induced improvements in the efficiency of appliances. Changes in revenues are a function of three components:

$$\text{Change in Revenues} = \sum_i [\, A_i - A_i' \,] * P_i \,,$$

$A_i'$ = Policy-case electricity sales in tier i,
$A_i$ = Base-case electricity sales in tier i,
$P_i$ = Price of electricity in tier i.

The first two terms, when summed over all tiers, are outputs of the modeling efforts described in the previous section. We direct our discussion here to the forecasts of the distribution of sales over the tiers and prices of electricity in each tier.

The residential rate structure for PG&E is an inverted one consisting of three tiers. Tier boundaries are set independently for each geographic region (R, S, T, and X) and, within regions, for customers with and without electric space heating (Classes H and B). Tier prices, on the other hand, are constant for all regions/rate classes. See Ref. 22 for a discussion of this process. The cumulative sales frequency distributions for each rate class, provided to us by the rate department of PG&E,[23] is the starting point for determining the distribution of sales over tiers. As these rate classes were in the process of being implemented at the time of our study, the distributions are, in fact, the merged distributions of the predecessors to the current rate classes. The tier boundaries are reproduced from the latest PG&E residential rate schedule in Figure 9.

For both the base and policy cases, we modeled the effect on revenues of changing levels of sales over time with the Block Adjustment Method. This technique is commonly used by the rate departments of utilities to measure the revenue impact of small changes in sales. The essence of the method is to adjust the tier boundaries for the existing distribution rather than attempt to generate a revised cumulative sales frequency distribution for each change in sales (real or hypothesized). In operation, the technique is to linearize changes in the tier boundaries in inverse proportion to changes in the mean levels of consumption. Analytically:

$$\text{Tier Boundary}' = \text{Tier Boundary} * [\text{Mean} \,/\, \text{Mean}'\,].$$

For the reductions in mean levels of use that result from increased appliance efficiencies, this method has the effect of decreasing the fractions of total sales taking place in the top tiers. For a utility with an inverted block rate structure (such as PG&E and DECO), this procedure results in estimating larger revenue losses than would result from simply multiplying an average price by the new level of sales.

An example of the effect of this adjustment over time for the base case summer sales in single rate class is presented in Figure 10. This figure indicates that sales per customer are declining since the trend has larger fractions of sales shifting to the lower tiers.

The basis for projected rates is current rates and the differentials between them. From each tier price in the current rate schedule, we subtracted the average cost of fuels used to generate electricity. The remaining component is called the base rate and represents the return on rate base, as well as other non-fuel costs. To these base rates, we added a levelized or trended rate base quantity to represent the amortization of the Diablo Canyon nuclear power plant and the Helms Creek pumped storage facility. This quantity resulted in a 50 % increase in the base rate of each tier. No effort was made to vary the assumed level of expenses allowed into the rate base for these projects.

Figure 9. PG&E residential class tariff sheet.

Pacific Gas and Electric Company
San Francisco, California

Revised Cal. P.U.C. Sheet No. 8764-E
Cancelling Revised Cal. P.U.C. Sheet No. 8727-E

SCHEDULE NO. D-1 -- RESIDENTIAL SERVICE

APPLICABILITY: This schedule is applicable to single-phase residential service in single-family dwellings and in flats and apartments separately metered by the Utility; to single-phase service in common areas in a multi-family complex; and to all single-phase farm service on the premises operated by the person whose residence is supplied through the same meter.

TERRITORY: The entire territory served.

RATES:

| ENERGY CHARGE: | | Per Meter Per Month |
|---|---|---|
| TIER I | BASELINE QUANTITIES, per kWh .................................. | $.06318 |
| TIER II | TIER II QUANTITIES, per kWh .................................. | $.08213 |
| TIER III | EXCESS, per kWh .............................................. | $.10677 |

MINIMUM CHARGE: $2.00.

SPECIAL CONDITIONS:

1. ANNUAL CONTRACT: For customers who use service for only part of the year this schedule is applicable only on an annual contract.
2. BASELINE RATES: Baseline rates are applicable only to separately metered residential usage. The Utility may require the customer to complete and file with it a Declaration of Eligibility for Baseline Quantities for Residential Rates.
3. TIER I (BASELINE) AND TIER II QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline and Tier II usage (see Rule No. 19 for additional quantities for medical needs):

BASELINE AND TIER II QUANTITIES (kWh PER MONTH)

| Baseline Territory* | Code B - Basic Quantities | | | | Code H - All Electric Quantities** | | | |
|---|---|---|---|---|---|---|---|---|
| | Summer | | Winter | | Summer | | Winter | |
| | Tier I | Tier II | Tier I | Tier II | Tier I | Tier II | Tier I | Tier II |
| R | 520 | 400 | 350 | 250 | 740 | 510 | 1,200 | 700 |
| S | 440 | 300 | 350 | 230 | 660 | 420 | 1,200 | 700 |
| T | 220 | 150 | 250 | 170 | 390 | 310 | 850 | 540 |
| V | 290 | 190 | 340 | 210 | 540 | 340 | 1,100 | 650 |
| W | 540 | 460 | 320 | 210 | 800 | 650 | 1,000 | 660 |
| X | 310 | 210 | 330 | 210 | 400 | 360 | 1,000 | 640 |
| Y | 350 | 250 | 360 | 250 | 480 | 310 | 1,200 | 790 |
| Z | 250 | 230 | 400 | 300 | 400 | 320 | 1,400 | 880 |

*The applicable baseline territory is described in Part A of the Preliminary Statement.
**Permanently installed electric heating as primary heat source.

4. Summer and winter Tier I (baseline) and Tier II quantities will normally be billed without seasonal proration for six consecutive billing periods beginning in the middle of the May and November billing cycles as described in Rule No. 9.
5. STANDARD MEDICAL QUANTITIES (Code M - Basic Plus Medical Quantities, Code S - All Electric Plus Medical Quantities): Additional medical quantities are available as provided in Rule No. 19.
6. ADDITIONAL METERS ON PREMISES: Additional meters on residential premises may be billed as baseline Code B - Basic or may be supplied under the applicable general service schedule.

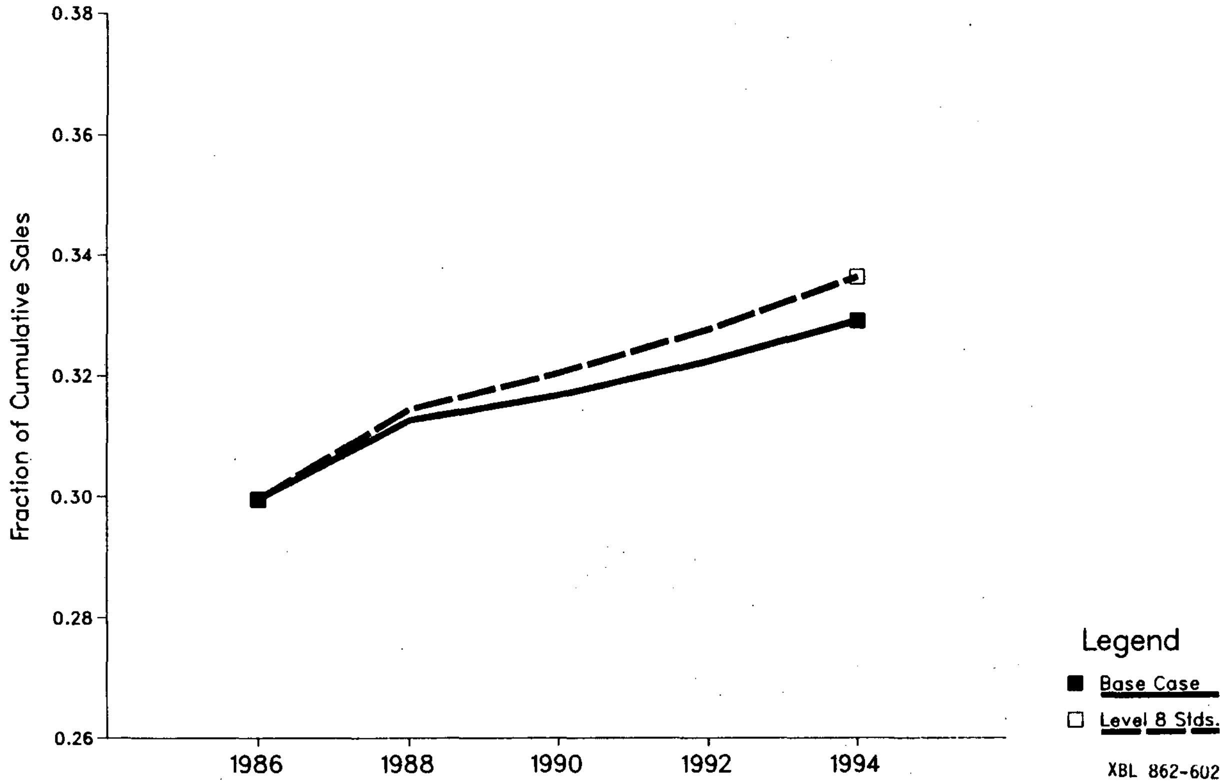
Advice Letter No. 1036-E
Decision No. 84-08-118

JONE15(J01) p.14

Issued By
W. M. Gallavan
Vice-President
Rates and Economic Analysis

Date Filed August 10, 1984
Effective August 12, 1984
Resolution No.

Figure 10. Adjusted tier fractions for PG&E residential rate class R, summer season.




Finally, a quantity representing future average real costs of fuel was added to complete our estimation of future rates. The fuel costs were taken from the results of an electricity production cost simulation, which will be more fully described in the next section. We did not make any attempt to change the rate differentials between tiers; instead, we chose to hold these differentials fixed and distribute the additional rate base and fuel costs among them evenly. The rates used in the analysis are presented in Table 16.

The net impacts of the revenue changes for the base and policy cases are summarized in Table 17. For the LBL Level-8 appliance standards case, residential sales decline by 68.3 GWh (0.4 %) and 210.1 (1.3 %) in 1988 and 1992, respectively. Revenues, on the other hand, decline by 10.6 million (0.6 %) and 31.4 million (1.8 %) dollars, for the same years. The effect of the block adjustment method has been to reduce sales disproportionately in the highest priced, upper tiers. This trend is consistent both for other years and for the technology-forcing version of standards; selling less electricity places relatively more sales in the lower tiers. Had we used the average price in 1994, we would have understated the revenue loss of the Level-8 standard by nearly four million dollars (or about 11 % of the predicted loss).

We can represent the dynamic impacts of this policy by the time trend of the elasticities of changes in sales to changes in revenue. For the LBL Level-8 standard, the ratio of the percentage changes in kWh sales to revenues for 1988 is .683 increasing to .886 by 1994. We distinguish two effects. The first, that the ratio is less than unity, is just a restatement of the effect of using average prices and the block adjustment method in estimating revenue losses. The ratio would be unity, if average prices had been used. The second, that the ratio is increasing toward unity over time, indicates the revenue losses are getting smaller on a per unit basis. The driving force is our assumed trajectory of tier prices. Increases in these prices are more than compensating for the the effect of greater fractions of sales taking place in the lower tiers. That is, since we know average sales per customer are decreasing, we know that the block adjustment method is shifting sales to lower, less expensive tiers. Thus, if more sales are in lower price tiers while per unit revenue losses do not also decline, then prices must be increasing.

**Table 16. PG&E Tier Prices (1975 ¢/kWh)**

| | ELFIN Fuel Price | Tiers * I | II | III |
|---|---|---|---|---|
| 1984 | 1.23 | 3.09 | 3.99 | 5.11 |
| 1985 | 1.22 | 4.01 | 5.36 | 7.04 |
| 1986 | 1.26 | 4.05 | 5.40 | 7.08 |
| 1987 | 1.31 | 4.10 | 5.45 | 7.13 |
| 1988 | 1.35 | 4.14 | 5.49 | 7.17 |
| 1989 | 1.38 | 4.17 | 5.52 | 7.20 |
| 1990 | 1.41 | 4.20 | 5.55 | 7.23 |
| 1991 | 1.46 | 4.25 | 5.60 | 7.28 |
| 1992 | 1.52 | 4.31 | 5.66 | 7.34 |
| 1993 | 1.59 | 4.38 | 5.73 | 7.41 |
| 1994 | 1.67 | 4.46 | 5.81 | 7.49 |
| 1995 | 1.77 | 4.56 | 5.91 | 7.59 |
| 1996 | 1.88 | 4.67 | 6.02 | 7.70 |
| 1997 | 1.92 | 4.71 | 6.06 | 7.74 |

* Calculated as: ELFIN + 1.86, 2.76, 3.88 for 1984, and 2.79, 4.14, 5.82 afterwards.

**Table 17. PG&E Revenues Changes**

| | Sales (GWh) | Base Case Revenues (M1984dollars) | Sales (GWh) | Level-8 Revenues (M1984dollars) | Sales (GWh) | Level-8 & A/C Revenues (M1984dollars) |
|---|---|---|---|---|---|---|
| 1986 | 15465.8 | 1631.3 | 15465.8<br>(0) * | 0<br>(0) | 15465.8<br>(0) | 0<br>(0) |
| 1988 | 15612.1 | 1655.2 | 15543.8<br>(68.3) | 1644.6<br>(10.6) | 15515.5<br>(96.6) | 1642.0<br>(13.2) |
| 1990 | 15999.3 | 1701.4 | 15863.1<br>(136.2) | 1683.4<br>(18.0) | 15815.2<br>(184.1) | 1676.7<br>(24.7) |
| 1992 | 16485.7 | 1775.1 | 16275.6<br>(210.1) | 1743.6<br>(31.4) | 16206.7<br>(279.0) | 1736.3<br>(38.7) |
| 1994 | 16981.1 | 1857.4 | 16696.3<br>(284.8) | 1822.3<br>(35.1) | 16605.1<br>(376.0) | 1809.4<br>(48.1) |

* Differences from base case in parentheses.

### 3. Avoided Production Costs

The corollary to selling less electricity is producing less electricity. The value of these reductions, moreover, is properly valued at marginal cost of generation, which, is the most expensive to the utility on an incremental basis. This value represents a benefit to the shareholders of a utility in the form of reduced operating costs.

Unlike DECO, there are significant cost transitions in the marginal cost curve for PG&E. These transitions fluctuate in time, both within years and across them. Since we expected load modifications that would not be evenly distributed over the year, we had to represent the avoided costs on a time-scale that was commensurable with these savings. The "very ticklish problem of coincidence" that could be cleverly side-stepped for DECO[2] had to be met head-on for PG&E. Its resolution forced us to abandon production costing techniques that rely on an annual load duration curve and seek out a more detailed representation of PG&E generation mix through time.

The major cost transition for PG&E occurs when the marginal fuel switches from oil or gas to geothermal and, to a lesser extent, hydro. The transition point varies monthly according to the seasonal availability of low-cost hydro power and yearly, as the generation mix is modified.

Calculations of the optimal dispatching of generation units for a given future load are typically performed by sophisticated computer models. We used the results of one such model to develop a structural characterization of the PG&E generating system over time. This model, called ELFIN, provides an explicit representation of the monthly marginal cost structure, which is only implicit in PG&E's in-house production costing model.[24] Given this representation, we could then utilize recent cost data from the company to complete our characterization. We recognize that, in addition to standard disputes over the correct set of input assumptions, substantive differences in calculational procedures exist between models.

We distinguished three components of the PG&E marginal cost structure. They are the average annual heat rate of the system, the annual non-oil and -gas fraction, and the monthly distribution of these fractions. We observed, first, that an annual non-oil and -gas fraction (thinking now in terms of an annual load duration curve) could be roughly correlated with an average annual heat rate (see Figure 11). These annual fractions appeared to be uniquely related to a distribution of such fractions for individual months (see Figure 12). Modifications in the generation mix over time, then, have the effect of attenuating the distribution of monthly transitions to non-oil and -gas fuels uniformly over the year.

We used these observations in the following manner. First, a trajectory of annual non-oil and -gas fractions was chosen to represent a near-term excess of capacity, which declines linearly to a low point in the mid 1990's. To each year, an annual average heat rate was then assigned corresponding to an interpolation from Figure 11. These assumptions are contained in Table 18. Finally, a monthly distribution of non-oil and -gas fractions was chosen corresponding to a distribution from the ELFIN year, whose annual non-oil and -gas fraction is closest to the one used in the trajectory.

Into this structure of marginal costs, we derived average monthly marginal costs by using the future prices for oil/gas, and geothermal energy presented in recent testimony from PG&E.[25] See Table 19 for these future prices and the resulting monthly average marginal costs. Once again, we stress the "PG&E-like" nature of our analysis and recognize that our desire to capture the flavor of PG&E's marginal costs may have produced results that are in variance with existing projections of these costs.

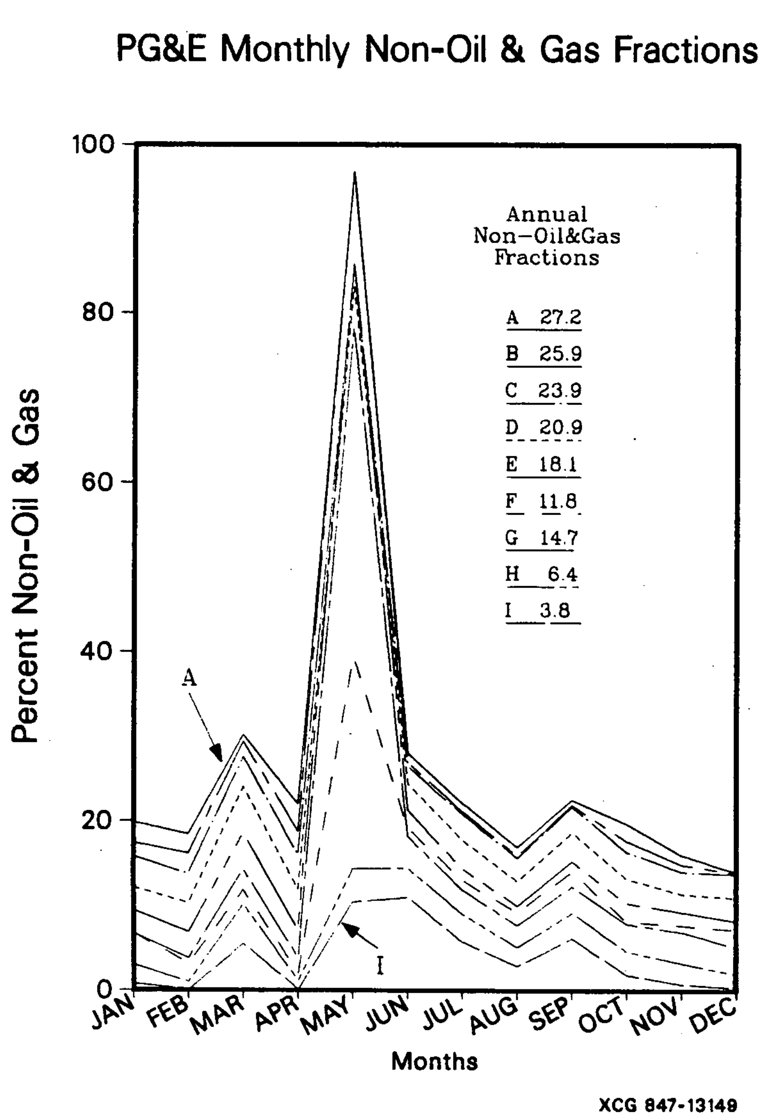



Figure 12. PG&E Monthly Non-Oil and Gas Fractions.

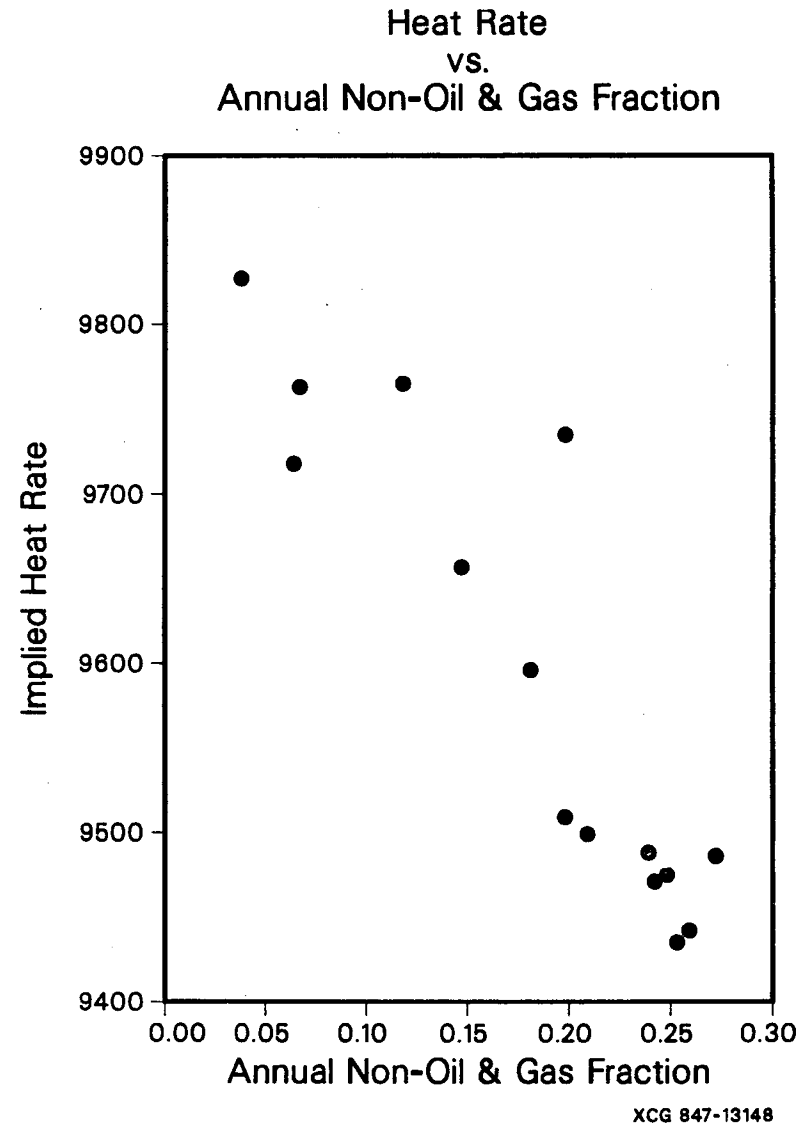



Figure 11. Heat Rate vs. Annual Non-Oil and Gas Fraction.

**Table 18. PG&E Annual Non-Oil-and-Gas Fractions and Heat Rates**

| Year | Non-Oil-and-Gas Fraction | ELFIN Year | ELFIN Actual | Heat Rate |
|---|---|---|---|---|
| 1984 | 27 | 1985 | 27.2 | 9480 |
| 1986 | 23 | 1989 | 23.9 | 9540 |
| 1988 | 19 | 1993 | 18.1 | 9600 |
| 1990 | 15 | 1994 | 14.7 | 9660 |
| 1992 | 11 | 1998 | 11.8 | 9720 |
| 1994 | 7 | 1995 | 6.4 | 9780 |
| 1996 | 3 | 1996 | 3.8 | 9840 |

**Table 19. PG&E Marginal Costs**

| Year | 1986 | 1988 | 1990 | 1992 | 1994 | 1996 |
|---|---|---|---|---|---|---|
| Geo Price (mills) | 27.88 | 30.11 | 34.41 | 41.47 | 48.81 | 65.39 |
| Oil Price (dollars/MBTU) | 5.74 | 6.80 | 8.06 | 9.79 | 11.74 | 14.05 |
| Heat Rate | 9540 | 9600 | 9660 | 9720 | 9780 | 9840 |
| ELFIN Year | 1989 | 1993 | 1994 | 1998 | 1995 | 1996 |
| Month | Marginal Cost * | Marginal Cost | Marginal Cost | Marginal Cost | Marginal Cost | Marginal Cost |
| Jan | 50.51 | 61.97 | 74.97 | 91.57 | 112.84 | 137.73 |
| Feb | 51.06 | 62.86 | 76.21 | 93.45 | 114.18 | 138.22 |
| Mar | 47.34 | 58.75 | 71.64 | 88.78 | 108.08 | 134.24 |
| Apr | 50.46 | 62.77 | 76.17 | 94.05 | 114.06 | 138.16 |
| May | 31.86 | 35.07 | 43.83 | 73.95 | 105.28 | 130.59 |
| Jun | 47.63 | 57.81 | 69.97 | 84.86 | 105.27 | 130.18 |
| Jul | 49.17 | 60.23 | 72.70 | 88.19 | 108.85 | 134.08 |
| Aug | 50.55 | 61.76 | 74.51 | 90.17 | 111.44 | 136.13 |
| Sep | 48.92 | 59.91 | 72.50 | 87.60 | 108.74 | 133.74 |
| Oct | 50.36 | 61.65 | 74.43 | 90.78 | 111.75 | 136.90 |
| Nov | 50.99 | 62.02 | 74.87 | 91.05 | 112.69 | 137.73 |
| Dec | 51.06 | 62.40 | 77.86 | 95.16 | 114.82 | 138.25 |
| 0 % Non-O&G | 54.76 | 65.28 | 77.86 | 95.16 | 114.82 | 138.25 |

* Marginal costs in current mills/kWh.

To calculate the production costs avoided by the exogenous load shape change, we translated the monthly changes in kWh sales into generation-level reductions by accounting for transmission and distribution losses. Recent PG&E testimony provided us with a factor of 6 % to use in making this translation.[26] Next, we multiplied the monthly differences in sales by the monthly average marginal costs and summed for the year. Formally:

$$\text{Avoided Production Cost} = \sum_i \left[ (\text{Sales}_i - \text{Sales}_i') * \text{loss factor} * \text{Marginal Cost}_i \right],$$

$\text{sales}_i$ = base case sales in month i,

$\text{sales}_i'$ = policy case sales in month i,

loss factor = 1.06 (generation kWh/ sales kWh),

$\text{marginal cost}_i$ = marginal production cost in month i.

For the policy case that contains a technology forcing air-conditioning standard, we valued the additional kWh savings (beyond those already calculated) using a 0 % non-oil-and-gas fraction. The logic is similar to that used in the DECO analysis; these load reductions take place at times of the day when the utility is will avoid oil and gas, exclusively.

**4. Capacity Credit**

The final component of financial impact and only tangible one for PG&E, given ERAM, is a capacity credit for the reliability benefits conferred on the system by reduced loads at times of system peaks. We measured the capacity impact by examining the magnitude of load modifications during periods of critical system loads. We valued this avoided capacity by applying published PG&E offers for fifteen years of firm capacity, which is the average lifetime for efficient appliances.

Loss of Load Probabilities (LOLP) are standard statistics used for quantifying the reliability of generating systems.[27] PG&E uses hourly calculations of these values to determine both costing periods and, for these periods, allocation factors for the demand-related generation and transmission components of cost.[26] We conclude from the exponential nature of LOLP's and the concentration of the LOLP in the summer peak period that the critical periods for the PG&E system are concentrated in a relative handful of hours during the summer peak period.

With this understanding, we represented the capacity savings of our policy scenarios by the average kW change occurring during the hours of noon to 8 p.m. on four summer class peak days. PG&E load studies show that class peak days are strongly correlated with system peak days; hot weather is the common driving force.[18, 19] We then weighted these changes upward by 6 % for transmission losses and 20 % for a reserve margin allowance to represent the total, generation-level savings.

We treated these savings as firm capacity being sold to the utility. PG&E offers payments for firm capacity from cogenerators and small power producers with a levelized offer for variable contract lengths.[28] Figure 13 is a reproduction of a recent set of offers. We used the payments offered for a fifteen year contract as our starting point (the expected average lifetime of the appliances). The capacity payments for cogenerators and small power producers are based on the avoided revenue requirements associated with the purchase of a combustion turbine. For the calculation of the capacity value of the policy-induced shifts in demand, we reduced the payments offered to small power producers to isolate the component of revenue requirements represented by capital expenses (see Ref. 29 for a worked example of this relationship). We have approximated the relationship by a simple ratio of 1.7. Finally, the fifteen year annuity is discounted at the company's real cost of capital (8%). For savings taking place with starting years beyond those in the PG&E schedule, we made a simple linear extrapolation (see Table 20). Formally:

$$\text{Capacity Value} = (\text{MW} + \text{lf} + \text{rmf}) * \text{CP}(15) * \text{CRRf} * \text{PV}(15\text{ yr}, 8\%),$$

S = average change in demand between 12 pm and 8 pm on four summer peak days,
lf = loss factor (6 %),
rmf = reserve margin factor (20 %),
CP(15) = PG&E capacity payment for 15 year term,
CRRf = capital component of revenue requirement factor (1/1.7),
PV(15 yr, 8%) = present value of a 15 year annuity at 8 %.

Figure 13. PG&E firm capacity price offers.

**TABLE E**

**PACIFIC GAS AND ELECTRIC COMPANY**

**FIRM CAPACITY PRICE SCHEDULE**
**(Levelized $/kW-Year)**

**STANDARD OFFER #2**

**EFFECTIVE JANUARY 1, 1984**

| Actual Operation Date (Year) | Term of Agreement 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 20 | 25 | 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1983 | 72 | 111 | 96 | 88 | 84 | 85 | 88 | 91 | 93 | 96 | 98 | 100 | 102 | 104 | 106 | 115 | 122 | 128 |
| 1984 | 156 | 111 | 95 | 88 | 89 | 92 | 95 | 98 | 100 | 103 | 105 | 108 | 110 | 112 | 114 | 124 | 131 | 137 |
| 1985 | 60 | 58 | 59 | 66 | 73 | 79 | 84 | 88 | 92 | 95 | 99 | 102 | 104 | 107 | 110 | 121* | 127* | 135 |
| 1986 | 56 | 58 | 69 | 78 | 85 | 90 | 95 | 99 | 103 | 106 | 110 | 113 | 116 | 118 | 121 | 132 | 141 | 148 |
| 1987 | 61 | 77 | 88 | 95 | 101 | 105 | 109 | 113 | 117 | 120 | 124 | 127 | 130 | 132 | 135 | 147 | 156 | 163 |
| 1988 | 96 | 104 | 110 | 115* | 119 | 122 | 126 | 129 | 133 | 136 | 139 | 142 | 145 | 148 | 151 | 163 | 173 | 180 |

* In its Application for Rehearing and/or Petition for Modification of CPUC Decision 83-12-068 (December 22, 1983) filed on February 6, 1984, PGandE requests correction of three numbers which were incorrectly presented in the Firm Capacity Price Schedule included in that decision (page 349, Table VI-4). The correct number for 1985 for a 20-year contract life should be $120/kW-year; and for a 25-year contract life, the correct number should be $129/kW-year. The correct number for 1988 for a 4-year contract life should be $114/kW-year. When the CPUC issues an order correcting these numbers, PGandE shall correct the Firm Capacity Price Schedule accordingly.

**Table 20. Capacity Credit**

| Year | Capacity Price 15-Year Term | Capacity Price (1984 dollars/kW-yr) * | Capital (1984 dollars/kW-yr) | Capacity Credit (1984 dollars/kW-15yr) |
|---|---|---|---|---|
| 1985 | 110 | | | |
| 1986 | 121 | | | |
| 1987 | 135 | | | |
| 1988 | 151 | 124.23 | 73.08 | 625.57 |
| trend | (1.111) | (1.058) | (1.058) | |
| 1989 | 167.82 | | | |
| 1990 | 186.51 | 139.18 | 81.87 | 700.81 |
| 1991 | 207.28 | | | |
| 1992 | 230.37 | 163.72 | 96.31 | 824.41 |
| 1993 | 256.03 | | | |
| 1994 | 284.54 | 174.68 | 102.75 | 879.54 |
| 1995 | 316.23 | | | |
| 1996 | 351.45 | 195.70 | 115.12 | 985.43 |
| 1997 | | | | |
| 1998 | 434.10 | 219.25 | 128.97 | 1103.98 |
| 1999 | | | | |
| 2000 | 536.18 | 245.63 | 144.49 | 1236.83 |

* Inflation at 5 %/yr.

## 5. Financial Impacts on PG&E

The avoided production costs are summarized along with the results for the operating margin changes (i.e., including the revenue losses) in Tables 21 and 22 for the Level-8 and Level-8 with technology-forcing air conditioner standards, respectively. The changes in the operating margins are roughly the same. The Level-8 standard differs from the special, air-conditioning version by inducing smaller sales losses (see Residential Energy Use and Peak Demand Forecasts for PG&E). Smaller sales losses mean that per unit revenue losses are slightly less due to the block adjustment method. The per unit operating margin changes are further exaggerated between the two cases by the higher average production costs resulting from the zero percent non-oil and -gas fraction assumed for the additional air conditioning savings.

**Table 21. Operating Margin Changes Level-8 Appliance Standards**

| Year | Sales Changes (GWh) | Revenue Changes (M1984dollars) | Production Cost (1984 mills) | Avoided Costs (M1984dollars) | Operating Margin (M1984dollars) |
|---|---|---|---|---|---|
| 1988 | 68.3 | 10.6 | 48.83 | 3.5 | -7.1 |
| 1990 | 136.2 | 18.0 | 53.28 | 7.7 | -10.3 |
| 1992 | 210.1 | 31.4 | 60.09 | 13.4 | -18.0 |
| 1994 | 284.8 | 35.1 | 67.86 | 20.5 | -14.7 |

**Table 22. Operating Margin Changes Level-8 Appliance Standards A/C SEER=12**

| Year | Sales Changes (GWh) | Revenue Changes (M1984dollars) | Production Cost (1984 mills) | Avoided Costs (M1984dollars) | Operating Margin (M1984dollars) |
|---|---|---|---|---|---|
| 1988 | 96.6 | 13.2 | 50.50 | 5.2 | -8.0 |
| 1990 | 184.1 | 24.7 | 54.53 | 10.7 | -14.0 |
| 1992 | 279.0 | 38.7 | 61.16 | 18.1 | -20.6 |
| 1994 | 376.0 | 48.1 | 68.50 | 27.3 | -20.8 |

The gap between the two components of the operating margin decreases over time. For the Level-8 standards, the per unit revenue loss decline from 0.16 dollars/kWh to 0.15 dollars/kWh from 1988 to 1992. The per unit production costs, on the other hand, increase from 0.05 dollars/kWh to 0.06 dollars/kWh for the same years. If these rates continued, parity would be reached between 2004 and 2005.

Tables 23 and 24 summarize impact of the capacity credit for the two policy cases. For the Level-8 standard, the capacity credit serves to reduce the operating margin losses slightly. A more meaningful comparison can be made by treating the capacity credit as a special kind of avoided cost savings. Expressed in this format, the capacity credit is 0.05 dollars/kWh in 1988, roughly equivalent to the avoided energy cost. By 1992, this quantity has declined to 0.02 dollars/kWh.

For the technology-forcing air conditioning standard, however, the value of capacity credit is substantial. All operating margin losses are more than compensated for by this credit. Expressed as a dollar value per conserved kWh, the capacity credit is worth 0.25 dollars/kWh in 1988 and 0.09 dollars/kWh in 1992.

Table 23. PG&E Capacity Savings: Level-8 Appliance Standards (M 1984 dollars)

| Year | Base Case Avg. Load (MW) | Stds Case Avg. Load (MW) | Delta (MW) | Tran. Loss + Res. Margin (6 %, 20 %) | Incremental Savings (MW) | Capacity Payment (dollars/kW-15yr) | Capacity Value * (M dollars) |
|---|---|---|---|---|---|---|---|
| 1988 | 2398.53 | 2390.04 | 8.49 | 10.80 | 10.80 | 625.57 | 6.8 |
| 1990 | 2484.28 | 2467.33 | 16.95 | 21.56 | 10.76 | 700.81 | 7.5 |
| 1992 | 2580.61 | 2554.50 | 26.11 | 33.21 | 11.65 | 824.41 | 9.6 |
| 1994 | 2666.22 | 2631.08 | 35.14 | 44.70 | 11.49 | 879.54 | 10.1 |
| 1996 | 2740.00 | 2695.66 | 44.34 | 56.40 | 11.70 | 985.43 | 11.5 |
| 2000 | 2917.86 | 2856.30 | 61.56 | 78.03 | 21.90 | 1236.83 | 27.1 |

Table 24. PG&E Capacity Savings: Level-8 Appliance Standards A/C SEER=12 (M 1984 dollars)

| Year | Base Case Avg. Load (MW) | Stds Case Avg. Load (MW) | Delta (MW) | Tran. Loss + Res. Margin (6 %, 20 %) | Incremental Savings (MW) | Capacity Payment (dollars/kW-15yr) | Capacity Value * (M dollars) |
|---|---|---|---|---|---|---|---|
| 1988 | 2398.53 | 2338.53 | 60.00 | 76.32 | 76.32 | 625.57 | 47.7 |
| 1990 | 2484.28 | 2378.95 | 105.33 | 133.98 | 57.66 | 700.81 | 40.4 |
| 1992 | 2580.61 | 2427.71 | 152.90 | 194.49 | 60.51 | 824.41 | 49.9 |
| 1994 | 2666.22 | 2462.23 | 203.99 | 259.48 | 65.00 | 879.54 | 57.2 |
| 1996 | 2740.00 | 2486.16 | 253.84 | 322.88 | 63.40 | 985.43 | 62.5 |
| 2000 | 2917.86 | 2592.53 | 325.33 | 413.82 | 90.94 | 1236.83 | 112.5 |

# IV CONCLUSIONS FROM MODELING PG&E

Our case study of PG&E benefited greatly from the experiences gained from the DECO study. We were able to tie the modeling effort much more closely to the financial impact calculations with rewards for both components of the study. In particular, the decision to study individual rate classes resulted in increased flexibility for tuning the models and greater accuracy in calculating revenue impacts. The price for this increased level of detail was a far greater data requirement. In this respect, we were fortunate to have chosen PG&E because much of this information had already been collected in an easily accessed format.

The availability of a much richer data base not only gave us increased confidence in our results but also allowed us to identify areas where the models could be further refined. We noted three such tasks:

- The explicit disaggregation of resistance and heat pump electric space heating appliances (and link to central air conditioning for heat pumps).
- Additional validation and refinement of the empirical data base of the Hourly and Peak Demand Model, specifically, the end-use load shapes.
- The introduction of additional end-use categories to reduce the fraction of sales in the miscellaneous category.

We developed a detailed and flexible structure for the analysis of the financial impacts of load shape changes for PG&E. This structure allowed us to calculate individual rate class revenues changes seasonally, monthly avoided production costs, and annual capacity benefits. The generic nature of our representation could be easily updated to agree with more recent PG&E data or, perhaps more importantly, to assess the relative importance of foreseeable changes in the form of sensitivity studies.

Our results illustrated the value of appliance standards that target end-uses. The Level-8 standards induced small, relatively uniform changes in the load shape. Uniform changes, when average revenues exceed marginal costs and capacity benefits are small, result in financial losses to PG&E stockholders (see Table 25). When the same standards were coupled with a technology-forcing high efficiency air conditioner standard, however, substantial capacity benefits accrued (see Table 26). These benefits, moreover, arise from the individual circumstances of the PG&E system; they would be of little value to a utility with excess capacity (e.g., DECO). These benefits far outweighed the operating margin losses and suggest that the returns would have been even greater for a standard that did nothing but increase the efficiency of air conditioning appliances.

The interested reader is directed to our summary document for an overview of all three case studies.[1] This document provides additional motivation for our decision to study the financial impacts on utilities of load shape changes and discusses the general approaches we used to do so. Finally, for each utility studied to date, companion technical reports detailing specific modeling procedures and intermediate results are also available.[2, 3]

**Table 25. PG&E Financial Impact Summary Level-8 Appliance Standards**

| Year | Sales Changes (GWh) | Operating Margin (M1984$) | Capacity Credit (M1984$) | Net Gain/Loss (M1984$) |
|---|---|---|---|---|
| 1988 | 68.3 | -7.1 | 6.8 | -0.3 |
| 1990 | 136.2 | -10.3 | 7.5 | -2.8 |
| 1992 | 210.1 | -18.0 | 9.6 | -8.4 |
| 1994 | 284.8 | -14.7 | 10.1 | -4.6 |

**Table 26. PG&E Financial Impact Summary Level-8 Appliance Standards A/C SEER=12**

| Year | Sales Changes (GWh) | Operating Margin (M1984$) | Capacity Credit (M1984$) | Net Gain/Loss (M1984$) |
|---|---|---|---|---|
| 1988 | 96.6 | -8.0 | 47.7 | 39.7 |
| 1990 | 184.1 | -14.0 | 40.4 | 26.4 |
| 1992 | 279.0 | -20.6 | 49.9 | 29.3 |
| 1994 | 376.0 | -20.8 | 57.2 | 36.4 |

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# APPENDICES

# Appendix A

## Sample Calculation of Household Additions by Region.

*1) Data and calculations.* Total additions for the PG&E service area, plus stock of households each year are provided. The decay rate (for retirement of houses) is calculated for the total service area and assumed constant for all regions. Decay rate = (additions - increment) / stock. For PG&E, the stock changes from 3291.5 thousand households in 1981 to 3373.6 in 1982, or an increment of 82.1 . Total additions are 139.1 . The decay rate is (139.1 - 82.1) / 3291.5 = 0.0173 .

*2) Additions = increment plus replacements.* The total number of households added to a region (additions) is the sum of two terms: first, the increase in the number of households in the region; and second, the number of replacements (retirement of one household compensated by construction of one household). Increments are calculated from two years of stock by region; replacements are the product of stock and decay rate. Table A-1 illustrates the data and calculations for 1982.

Table A-1. Household additions by region, PG&E 1982.

| Region | Stock | | Increment | Replacement | Additions |
|---|---|---|---|---|---|
| | 1982 | 1981 | | | |
| R | 243.8 | 230.3 | 13.5 | 4.0 | 17.5 |
| S | 401.1 | 395.2 | 5.8 | 6.8 | 12.6 |
| T | 756.9 | 757.5 | -0.6 | 13.1 | 12.5 |
| X | 1125.9 | 1085.4 | 40.5 | 18.8 | 59.3 |
| Z | 845.9 | 823.0 | 22.9 | 14.3 | 37.2 |
| Total | 3373.6 | 3291.5 | 82.1 | 57.0 | 139.1 |

The increment is calculated as the difference between the 1982 and 1981 stocks. Replacement is the product of decay rate times 1981 stock. Additions are the sum of increment and replacement.

Note that in the projected years 1985-2004, where the stock of households by region is proportional to the total stock, the calculation can be simplified. Each region's share of the total increment is the same fraction as its share of the stock..

# Appendix B

## Assignment of Appliance Saturations by Rate Class

The steps involved in obtaining a forecast for one region are:

1) Define initial appliance saturations for region. Perform first forecast with initial inputs, including marginal unit energy consumption (EUNN), to obtain discount rates for efficiency choice.
2) Second forecast uses constant discount rates for efficiency choice.
3) Separate appliance holdings into rate classes, based on saturation of electric space heat.
   a) Separate electric heat from non-electric heated households.
   b) Within non-electrically heated households, separate into gas and non-gas use for each end use.
   c) Within each class, separate non-gas use for each end use into electric and non-electric.
4) Final sales forecast is performed by rate class within each region, using constant discount rates for efficiency choice.

This appendix outlines step 3, as executed for the analysis of Pacific Gas and Electric Company (PG&E). The two rate classes are: B (no electric space heating) and H (with electric space heating). PG&E defines class H as all customers who are not gas customers. Therefore, all gas consumption for all end uses is assigned to class B. In both rate classes, for end uses other than space heating, electricity can be used, or the appliance may be absent. The proportion of non-gas households lacking an appliance is kept constant across rate classes. This is equivalent to maintaining the fraction of competing electric appliances constant in non-gas households.

The number of households in class H each year is the product of the saturation of electric space heating times the total number of households. In the following, region S is used as an example. The initial saturations of appliances are derived for each rate class as follows.

*SPACE HEAT.* All electrically heated households, and only electrically heated households, are in class H. The saturation of electrically heated households in the region is 19.9%. In class H, the saturation of electrically heated households becomes 100%. In class B, the saturation of gas households becomes the regional saturation (45.2%) divided by the regional saturation of non-electric heating systems (100-19.9 = 80.1%), namely 56.4%. The analogous calculation is performed for "other fuel" and "none" in class B. (See Figure 1.)

*REFRIGERATOR, FREEZER.* Regional saturation assumed constant across rate classes.

*WATER HEATING.* From above, 80.1% of the households in the region are in class B. All gas water heating must occur in class B. Since 46.8% of the households in the region have gas water heating, the saturation of gas water heaters in class B households is 46.8/80.1 = 58.4%. The remainder of the households in class B (100-58.4 = 41.6%) must have electric water heating or none. The shares of electric and none in this class are assumed proportional to the regional shares. The regional share of electric water heaters in households without gas water heaters is the ratio of regional saturation of electric water heaters divided by the sum of saturations of electric and none (13.1/(13.1+40.1) = 24.6%). Since 24.6% of the households without gas water heaters have electric water heaters, then 24.6% of class H households have electric water heaters, and 24.6% of class B households without gas water heaters have electric water heaters. Therefore, 24.6 x 41.6 = 10.2% of class B households have electric water heaters. Similarly, 75.4 x 41.6 = 31.4% of class B households have neither electric nor gas water heaters. (See Figure 2.)

*COOKING, DRYING.* The procedure is the same as for water heating. All gas consumption is assigned to class B, then the regional saturations of electric and none are apportioned between classes B and H.

*MISCELLANEOUS.* The saturation of miscellaneous is a fictional device to allow future penetration of phantom appliances, that is, end uses which are not explicitly modeled. In order to maintain the average initial saturation of miscellaneous at 50%, the saturation by rate class is adjusted in the same manner as for water heaters, cooking, and clothesdryers. All the miscellaneous gas consumption is assigned to class B, and electric consumption is apportioned between the two rate classes.

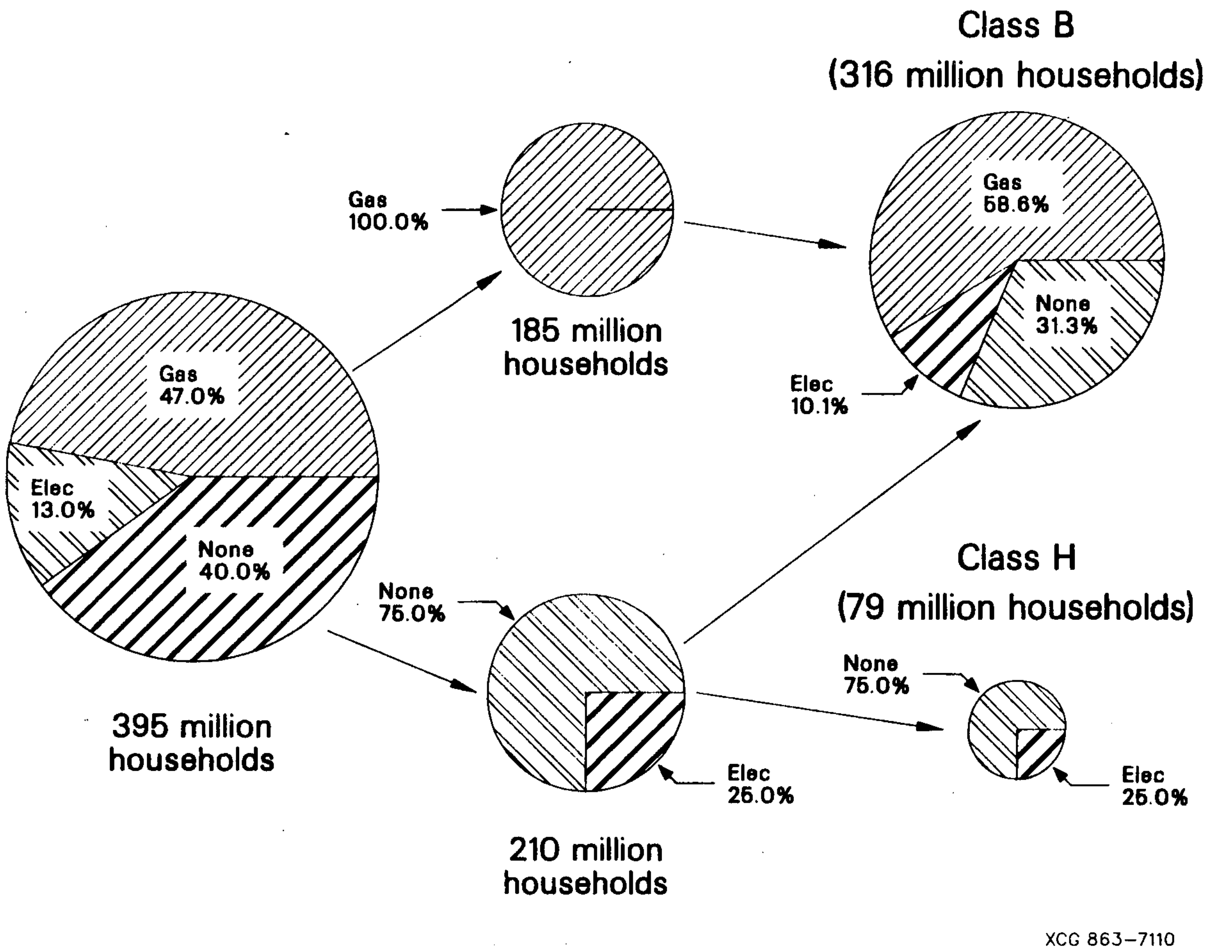


Figure 1. Rate Classes in PG&E Region S, 1981

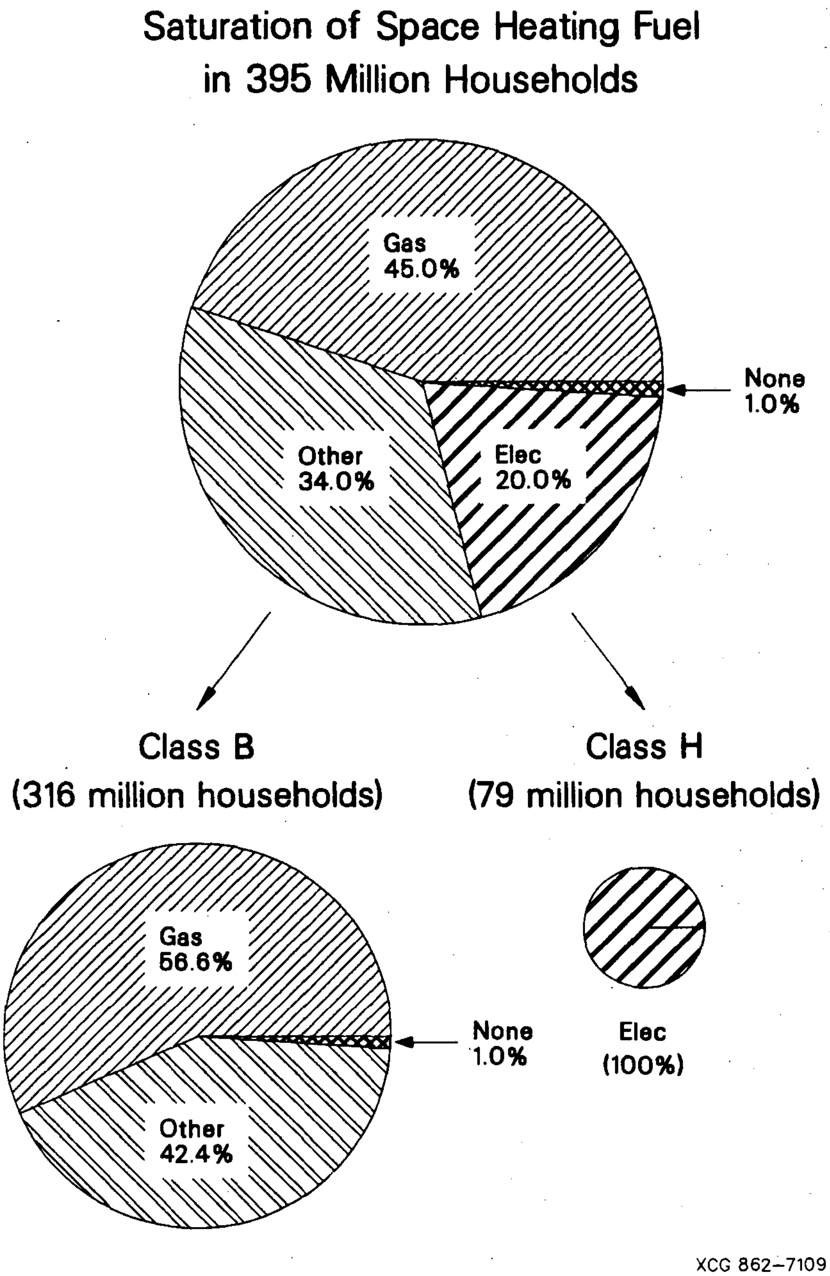


Figure 2. Water Heating Fuel Saturations (PG&E Region S, 1981)

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