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APPLIED SCIENCE DIVISION

FINANCIAL IMPACTS ON UTILITIES OF LOAD SHAPE CHANGES

The Texas Utilities Electric Company

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

April 1986

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1. INTRODUCTION

The goal of this LBL project is to develop tools and procedures that measure the financial impacts of load shape changes to utility ratepayers and society. In this application, we study the financial impacts of 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 for the residential sector. This detail is essential for calculating production and capacity cost benefits, and tariff-class specific revenue changes. We use utility filings for the purchase of power from cogenerators to develop two methods for calculating avoided production cost. We are thus able to combine several analytical procedures commonly employed by the industry independent of one another to yield an integrated assessment of the financial impacts of load shape changes.

This report is the technical documentation for our case study of the Texas Power & Light (TP&L) service territory of the Texas Utilities Electric Company (TUEC). It provides the interested reader with the underlying assumptions, modeling procedures, and intermediate results used to assess the financial impacts of policies that increase the efficiency of residential appliances. A separate document describes the overall method and conclusions (Kahn, 1986a).

The TUEC case study is the fifth in a series of five utility case studies performed by LBL. In addition to TUEC, LBL has examined the financial impact of load shape changes on the Detroit Edison Company, the Pacific Gas and Electric Company, the Virginia Electric and Power Company, and the Nevada Power Company (Kahn, 1984; Pignone, 1984; Eto, 1984a; Eto, 1984b; Eto, 1986).

We remind the reader that the present study is a simplified and stylized characterization of the Texas Utilities Electric Company. For example, our study focuses on the residential class of the former Texas Power & Light service territory. Since 1984, TP&L, Dallas Power & Light, and Texas Electric Service Company have operated as a single company, TUEC, yet data was only readily available for the TP&L residential class. TP&L residential customers represent 47% of the TUEC residential class.

Even a simplified characterization of an electric utility, however, requires substantial data to run the models and to calculate financial impacts. TUEC staff members were extremely helpful in providing the bulk of this information as well as timely advice and guidance.[1]

The outline of the report is as follows. In the first section, we provide the setting for our case study with a description of the utility and details regarding the appliance efficiency standards. In the next section, we describe the energy forecasting 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 section concludes with a summary of the load shape impacts forecast by the models. The following section describes the valuation of the energy and demand impacts. We consider both ratepayer and societal perspectives. Much attention is devoted to the development of two methods for evaluating production cost benefits. The final section summarizes the results of our case study.

[1] We are especially grateful for the efforts of Mr. Art Eckholm, Mr. Rocky Miracle, and Mr. Don Simpson.

2. BACKGROUND

This section provides an introduction to the case study by summarizing major features of the utility and the appliance efficiency policies.

2.1 TEXAS UTILITIES ELECTRIC COMPANY

The subject of our case study is the residential class of the former Texas Power & Light (TP&L) service territory of the Texas Utilities Electric Company (TUEC). In 1984, Texas Power & Light, Dallas Power & Light, and Texas Electric Service were merged into the present TUEC. The TUEC is located in the northern half of the state of Texas. The TP&L service territory under examination is that portion of TUEC that surrounds, but does not include, the cities of Dallas and Fort Worth in the northeastern portion of the state (see Figure 2-1).

Through the consolidation of the three operating companies, TUEC has become one of the largest electric utilities in the country. Sales in 1985 were forecasted to be 77049 GWh and with a peak demand of 15595 MW. Total residential class sales account for 33% of system generation. These figures correspond roughly to those for the subject of a previous case study, the Pacific Gas and Electric Company, and are approximately ten times greater those for the subject of our companion case study, Nevada Power Company.

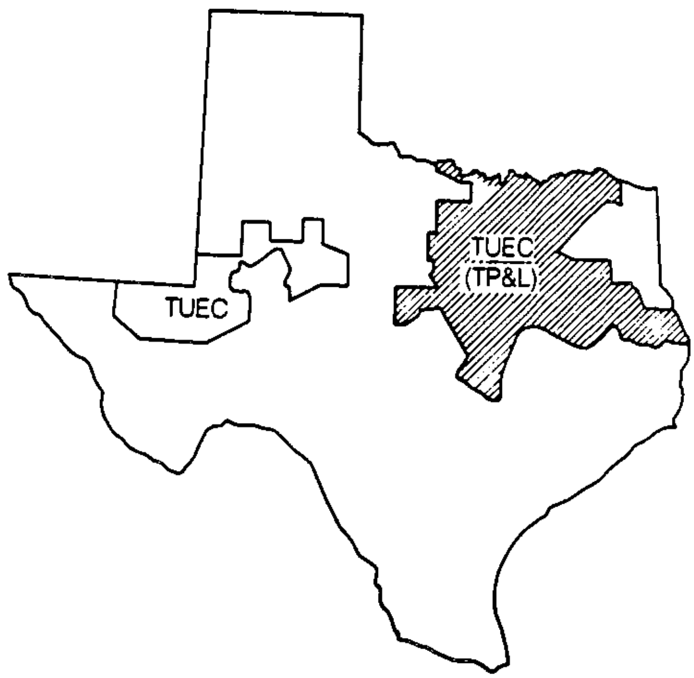

Figure 2.1 Texas Utilities Electric Company and former Texas Power & Light service territories.

TUEC anticipates continued strong demand growth into the 1990's. Electricity consumption is expected to increase at 3.3%/year from 1985 to 1999, and peak demand is expected to grow at 2.9%/year over the same period (according to the 1985 TUEC forecast). Growth should improve the TUEC system load factor, which is currently 56.4%. In general, the large fraction of TUEC sales accounted for by the residential class means that the load shape impacts of appliance efficiency policies will have important consequences for future system load factors.

TUEC costs are lower than national averages. In 1985, residential electric rates for 1000 kWh/mo were 0.070 $/kWh as compared to the national average of 0.076 $/kWh (DOE, 1985b). The utility is also in the process of phasing lower cost coal plants into the generation mix. Between 1985 and 1999, TUEC expects coal-fired generation to reduce the fraction of electricity generated by oil and gas from 52% to 18%. We expect that these relatively lower costs will have equally important consequences for our financial analyses of load shape modifications.

2.2 RESIDENTIAL APPLIANCE EFFICIENCY STANDARDS

In this case study, we examine the financial impacts of three appliance efficiency standards starting in 1987. These standards are imposed as the minimum efficiency requirement for new equipment. Table 2-1 compares the efficiencies mandated by each standard with existing efficiencies for each appliance. Existing efficiencies are described by both a stock-average or existing efficiency and a marginal or new appliance efficiency. Level 8 refers to a set of appliance efficiencies that are life-cycle cost-effective based on a nation-wide analysis. Level 8/12 refers to the same standard with the addition of an extremely high-efficiency central air conditioner standard. Level 12/AC refers to the isolated case of raising only room and central air conditioner efficiencies.

Table 2-1. Appliance Efficiency Comparison

Appliance	Existing	New	Level 8	Level 8/12	Level 12/AC
Space Heating (AFUE%)					
gas	63.79	70.18	85.72	85.72	--
oil	73.93	78.61	90.98	90.98	--
Air Conditioning					
room (EER)	6.54	7.17	8.87	8.87	8.87
central (SEER)	6.91	7.32	8.42	12.00	12.00
Water Heating (%)					
electric	80.75	81.31	93.60	93.60	--
gas	50.50	56.96	81.75	81.75	--
Refrigerators (ft^3/kWh/d)	4.88	6.35	11.28	11.28	--
Freezers (ft^3/kWh/d)	9.22	11.61	22.34	22.34	--
Ranges (%)					
electric	39.64	43.73	47.51	47.51	--
gas	16.29	29.27	20.27	20.27	--
Dryer (dry lbs/kWh)					
electric	2.72	2.88	2.96	2.96	--
gas (3413 Btu/kWh)	2.22	2.63	2.61	2.61	--

Source: LBL Energy Forecasting Model

3. MODELING LOAD SHAPE CHANGES

We use two unique models, both developed at LBL, to forecast the load shape impacts of policies that raise the efficiency of residential appliances. The first, the LBL Residential Energy Model, forecasts annual residential electricity sales by end-use and housing type. The second, the LBL Residential Hourly Demand and Peak Load Model, takes the output of the energy model and distributes annual electricity consumption, separately for each end-use, over the hours of the year. After describing the models in general terms, this section documents the input assumptions, benchmarking procedures, and load shape forecasts for our case study.

The LBL Residential Energy Model combines engineering information (costs and efficiencies of products available for purchase) and economic relationships (elasticities of demand separated into fuel choice, efficiency choice, and usage decisions) to provide simulations of future energy consumption at the end-use level. This approach considers the problem at a sufficient level of disaggregation to utilize engineering information without neglecting the important economic determinants of market behavior. The major improvements over earlier models include: representation of recent equipment efficiency trends; new techniques for forecasting future appliance efficiencies and annual appliance replacements; and extension of the model to include heat-pump space-conditioning systems (McMahon, 1986). The input assumptions to the model are numerous and we devote section 3.1 to a comprehensive review of these data.

The LBL Residential Hourly and Peak Demand Model is unique in representing diversified end-use load profiles for each hour of the year; most end-use load models simulate only selected day-types (Verzbinsky, 1984). The model is principally an engineering tool that disaggregates annual electricity sales by end-use, from the LBL Residential Energy Model, into seasonal and hourly loads. Space-conditioning end-use loads are specified as a function of both weather and time of day. In addition to the forecasts from the first model, the model requires hourly weather data.

Together, these two models provide an integrated forecast of electricity sales and hourly loads for the residential sector. A fully consistent forecast of electricity sales and loads by sector is unusual, even among electric utilities. Most utilities use either econometric models or load-factor analysis to estimate peak loads. Consequently, loads are often forecast as a function of sales, but without consistency between the end-use composition of sales and of load shapes. The Residential Energy Model also forecasts sales of alternative fuels (natural gas, heating oil, LPG); but, for studies of electric utilities, much less attention is given to these energy sources.

In operation, we first calibrate or benchmark the models to historical data on appliance saturations and electricity usage per customer. This process is described in section 3.2. The output of these efforts is a forecast of sales and hourly demands for a base or reference case. In 1987, appliance efficiency standards are imposed. The standards constrain 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. The effects of the appliance standards are the difference between the policy case and the base case. These impacts are summarized in section 3.3.

3.1 INPUTS TO THE LBL RESIDENTIAL ENERGY MODEL

This section documents the data and assumptions used to model the residential class of the Texas Power & Light service territory of the Texas Utilities Electric Company. Specifically, the LBL Model requires data on:

- appliance and heating equipment saturations and changes in appliance saturations over time;
- the saturations of appliances in new homes (marginal saturations or penetrations);
- the annual energy use of each appliance in the hase or other reference year;
- number of households, historical and projected;
- income per household, historical and projected;
- residential fuel and electricity prices, historical and projected; and
- the thermal integrity of housing units.

From these inputs, the model forecasts energy use for ten end-uses and three housing types for up to 25 years.

3.1.1 Appliance Saturations and Marginal Saturations

Table 3-1 contains total and marginal appliance saturations for TP&L. The primary source of data was the results of TP&L residential appliance saturation surveys conducted in 1981 and 1983 (TPL, 1984). The LBL SEEDIS database of U.S. Census data for each of the 49 counties in the TP&L service territory was also consulted for data not requested in the TP&L surveys (LBL, 1982).

The 1983 TP&L survey contained extensive disaggregation and cross-tabulation of the results. We used data on appliance saturations for homes less than two years old to develop marginal saturations. Where we had no data on marginal saturations, we assumed that the saturation for existing homes was the marginal saturation. Saturations for LP water heat and LP cooking appliances were taken from LBL SEEDIS database.

Table 3-1. Appliance Saturations and Marginal Saturations (% of total)

Function	Appliance	1981 Stock	Marginal (New Homes)
Heating	Electric Furnace	0.300	0.310
	Gas Furnace	0.520	0.320
	Heat Pump	0.030	0.220
	Electric Non-cent	0.039	0.039
	Gas Non-cent	0.030	0.030
	LP Non-cent	0.081	0.081
Cooling	Elect Cent A/C (excluding heat pumps)	0.630	0.620
	Heat Pump	0.030	0.220
	One or more window A/C	0.270	0.097
	Avg # of window A/C for those who have them	1.700	1.700
	None	0.070	0.060
Water Heat	Electric	0.280	0.620
	Gas	0.590	0.270
	LP	0.110	0.110
	none	0.020	0.000
Cooking	Electric	0.460	0.750
	Gas	0.420	0.140
	LP	0.112	0.112
Clothes Drying	Electric	0.640	0.770
	Gas	0.120	0.047
Food Storage	Refrigerator (avg # per household)	1.107	1.100
	Freezer	0.470	0.450
Lighting	Lighting	1.000	1.000

Sources: *1983 TP&L Residential Appliance Saturation Survey*, 1984; LBL, 1982.

3.1.2 Appliance Energy Consumption

Table 3-2 summarizes the unit energy consumption (UEC) estimates developed for each appliance. UEC's for most appliances were obtained from data compiled by Dennis O'Neal at Texas A&M and adjusted, where appropriate, to an average Dallas weather year (O'Neal, 1985). The UEC for electric dryers and the weather adjusted UEC for heat pumps in the heating mode were taken from a conditional demand study performed by the Nevada Power Company (see Eto, 1986). We assumed that heat pumps in the cooling mode use the same amount of electricity as central air conditioners. Data on energy use by gas dryers was taken from the LBL library of default values (DOE, 1983b).

Table 3-2 Appliance Unit Energy Consumption (UEC)

Function	Appliance	UEC*
CentralHeat	Electric	56.38
	Natural Gas	45.87
	Heat Pump	40.30
Non-Central Heat	Electric	45.39
	Natural Gas	39.31
	LP	39.31
Cooling	Central A/C	58.73
	Room A/C	42.20
	Heat Pump	58.73
Water Heat	Electric	39.92
	Natural Gas	20.00
	LP	20.00
Cooking	Electric	13.78
	Natural Gas	9.50
Dryers	Electric	9.09
	Natural Gas	6.88
Food Storage	Refrigerator	16.10
	Freezer	16.04
Lighting	Lighting	9.78

* UEC = million Btu of resource energy (11,500 Btu/kWh).

Sources: O'Neal, 1985
DOE, 1983b
Eto, 1986

3.1.3 Existing and Projected Numbers of Customers

Our analysis used forecasted rates of growth in residential customers for the entire Texas Utilities Electric Company to project the number of customers. TUEC no longer forecasts growth in residential customers for each of its three component utilities separately, so only the aggregate forecast was available. Table 3-3 summarizes our estimates. The right hand column contains the number of new homes built each year, which equals the marginal change in the number of existing households plus one percent of existing households. This calculation is based upon an exponential retirement function for houses that requires that one percent of existing homes retire annually. The number of individually-metered residential customers for 1982 and 1983 were taken from TPL, 1983 and TPL, 1984, respectively. The number of customers in 1981 was interpolated from the 1982 value by using the forecasted growth rate above for the 1978-83 period. For the years 1978-83, the forecast predicted growth of 4.8%/yr; for the period 1983-88, it predicted growth at 3.6%/yr, but we used a growth rate of 3.7%/yr based on our interpretation of a personal communication with TUEC staff; and after 1988, TUEC forecasters expect the number of residential customers to grow at 3.8% annually (PUC of Texas, 1984; personal communication from TUEC).

Table 3-3 Number of Customers and Number of New Homes 1980-1995

Year	Total Customers	New Homes
1981	632920	0
1982	663300	38152
1983	688152	31485
1984	713614	32343
1985	740017	33539
1986	767398	34780
1987	795792	36067
1988	825236	37402
1989	856595	39611
1990	889146	41116
1991	922933	42679
1992	958005	44300
1993	994409	45984
1994	1032196	47731
1995	1071420	49545

Sources: TPL, 1984;
PUC of Texas, 1984.

3.1.4 Housing Type

Table 3-4 shows the distribution of housing by type in 1981. Due to the dominance of single family housing and the lack of data by end-use (e.g. unit energy consumption), we forecast only the average customer.

Table 3-4 Housing Type (1981)

Housing Type	Percent
Single family detached	84%
Multifamily	11%
Mobile Home	5%

Source: TPL, 1984.

3.1.5 Historical and Projected Income per Household

The data for 1981-84 were obtained from the BEA Survey of Current Business (BEA, 1985) and converted to 1975$ using the Consumer Price Index. Household income may grow at a slightly different rate than per capita income, but these two growth rates will be comparable as long as the number of persons per household does not change drastically.

To derive projected growth rates for personal income per capita, we first obtained the forecast of total personal income and population developed by the Bureau of Business Research at the University of Texas, Austin, for the state of Texas (BBR, 1985). We then adjusted the growth rates derived from the above forecasts, which were developed for the entire state of Texas, because the same study also notes tbat the Dallas-Ft. Worth area is expected to have higher population growth and lower total personal income growth relative to the entire State. With this adjustment, the forecasted annual rate of growth in per capita income drops by two tenths of a percentage point, resulting in forecasted rates of income growth of 2.2% annually (1984-94) and 2.3% annually for 1995-2010. Table 3-5 summarizes these estimates.

Table 3-5 Historical and Projected Personal Income

Year	Income (1975$/capita)
1981	6398
1982	6347
1983	6317
1984	6550
1985	6694
1990	7463
1995	8329

Source: Bureau of Business Research, Austin, 1985.

3.1.6 Residential Electricity Prices

Historical prices to the residential sector are shown in Table 3-6 (in 1975 dollars per million Btu of resource energy, calculated at 11,500 Btu per kWh): The 1981 and 1982 prices were obtained from The Energy Information Administration's "Statistics of Privately-Owned Utilities (Class A and B)", and the 1983 and 1984 prices were obtained from TUEC FERC Form 1 filings for 1983 and 1984 (DOE 1983a; DOE 1984;; TUEC, 1984a; TUEC, 1985a). TUEC projects that electricity prices will increase at 7% per year and that inflation will average 5% (personal communication from TUEC, 1985). These forecasts imply that TUEC expects 2% real growth in the electricity price for each year of the forecasting period (1985-1996).

3.1.7 Historical and Projected Residential Natural Gas Prices

Table 3-6 contains historical and projected prices for natural gas in the TP&L service territory. The prices were obtained from the local natural gas supplier, Lone Star Gas Company in Dallas (personal communication from Lone Star Gas Company, 1985). The price in 1984 includes a fixed charge per customer that has been spread over the average usage per customer. Lone Star Gas expects residential natural gas prices to increase at 7% per year from 1985-1993, and 6% per year from 1993-2008. Since TUEC estimates that inflation will average 5% per year during these periods, the real growth rates used for these periods are 2% and 1%, respectively.

3.1.8 Liquefied Gas Prices

To estimate prices for liquefied gases (LP), we used a price forecast from the World Oil/Fossil National Energy Model, authored by the Energy Projections and Analysis Division of the U.S. DOE (DOE, 1985a). The prices used in our analysis are contained in Table 3-6.

Table 3-6 Historical and Projected Energy Prices (1975$/MMBtu)

Year	Electricity*	Natural Gas	LPG
1981	2.888	2.187	4.814
1982	3.117	2.544	4.535
1983	3.226	2.708	4.272
1984	3.019	2.840	4.024
1985	3.080	2.897	3.899
1990	3.400	3.198	3.331
1995	3.754	3.462	3.900

*Electricity valued at 11,500 Btu/kWh, by convention.

Sources: DOE 1983a;
DOE 1984;
DOE, 1985a;
TUEC, 1984a;
TUEC, 1985a;
personal communication from TUEC;
personal communication from Lone Star Gas Co.

3.1.9 Thermal Integrity and Heating Loads of Housing Units

The LBL Residential Energy Demand Model requires estimates of the annual heating and cooling loads of both an average existing and a new house. NPC supplied information on annual heating and cooling loads for the average existing house and we used the DOE-2 building energy-use model (Curtis, 1984) to develop estimates of these loads for new houses. The DOE-2 outputs were not, however, used directly. Instead, we performed two simulations, one of an average existing house and a second of new house, both using an hourly weather tape for the Dallas-Fort Worth area. Both prototypes were developed from data on the thermal characteristics or thermal integrity (TI) of the average new and average existing house in the TP&L service from the 1983 TP&L Residential Appliance Saturation Survey (TPL, 1984). We then calculated the ratios (called the thermal integrity ratio) of annual heating and cooling loads for two houses. Formally,

$$\text{Thermal Integrity Ratio} = \text{Load}_{\text{new}} / \text{Load}_{\text{stock}}$$

where:

Load_{new} = heating or cooling load for new homes
$\text{Load}_{\text{stock}}$ = heating or cooling load for stock or average home

We used these ratios, not the actual DOE-2 outputs, to adjust data from TP&L on actual heating and cooling loads for the average existing house to those of new house. For cooling loads, we calculated a TI ratio of 0.888; for heating, we calculated a TI ratio of 0.788.

3.1.10 Default values

The following values were taken from the LBL default library (DOE, 1983b):

- cost vs. energy use curve for each appliance
- cost vs. energy-use curve for thermal integrity improvements
- market share elasticities
- usage elasticities
- floor area per household
- appliance lifetimes
- equipment costs
- appliance retirement functions
- unit energy consumption for gas dryers

3.2 MODEL CALIBRATION

The first step in using the LBL models to forecast future residential energy use and peak demands is calibration to historic data. The calibration takes the form of running the model with historic inputs and comparing the results to actual recorded demand and energy use.

The calibration process is limited only by the availability of data on historic consumption. For the TUEC case study, we examined both historic monthly sales and peak day hourly load shapes for 1981. Little additional data, notably time-series data, were available. Before discussing the results of the calibration, we describe two important components of any calibration to historic data: weather and the load shape for miscellaneous end-uses.

Unit energy consumptions for weather-dependent end-uses (space conditioning) were adjusted from their 1981 values to agree with average weather. Scaling was done by heating and cooling degree-days, calculated at base 65 F. Average weather was used to drive the LBL Residential Hourly and Peak Demand Model.

The load shape for miscellaneous end-uses was assumed to be flat over all hours of the year. Since we do not know the composition of end-uses comprising the miscellaneous category, the true load profile is unknown. The alternative to a flat load profile is a derived one, which reduces the mismatch with the total residential load shape. For now, we are content to report that mismatch without using this handle to minimize it. We simply note that the assumed flat profile for miscellaneous contributes to some mismatch in the total residential load shape.

3.2.1 Monthly Sales

Monthly sales for 1980-81 were compared with model results for 1981. For this comparison, no attempt was made to adjust the model results to reflect actual weather; an average weather year is assumed in these model results. However, the total residential electricity consumed for the year was calibrated to agree with the total reported billing by TP&L. (Note that the model year was calendar 1981, but TP&L used October 1980 to September 1981. This means that for the months of October to December, two different years are being compared: 1981 for the model, and 1980 for the TP&L data.)

Space conditioning, which includes heat pumps, air conditioning, and electric space heating, represents about 56% of the TP&L residential sales (in 1981), so fluctuations of 10% in the weather could produce differences between estimates based on normal weather and actual residential sales of about 6%. Table 3-9 shows the results. Seven of the twelve months show errors of approximately 6% or less. The errors range from -21 to +19.1%, with a mean absolute percent error of 8.2%.

The model results agree well with the peak months of July and August (within 4%). Note that there is a strong seasonal dependence in TP&L sales; summer month sales are typically 2-2.5 times greater than those in the other six months of the year. The model also gives good agreement in the winter (within 5%, December to February).

The largest errors occur in spring and fall. Since the sales are lowest in these months, the large percentage errors correspond to smaller absolute errors. Possible sources of error in spring and fall are that there were more dramatic differences in weather from year to year, and that the model tends to overestimate cooling in the spring. We note that this finding is similar to that found in the Nevada Power Company and Detroit Edison case studies in which summer-like temperature profiles occur in spring, yet energy consumption patterns indicate that people open their windows rather than use the air conditioners (Eto, 1986; Pignone, 1984). The model underestimates in the fall are a phenomenon not observed for other utilities. For TP&L, the average weather in October and November leads the model to expect little heating or cooling. Apparently more space conditioning occurred in fall of 1980 than is reflected in the model's estimate based on average weather.

Table 3-9. LBL Backcast Compared to TP&L Monthly Residential Sales (GWh)

	LBL	TP&L	% difference
Jan	599.3	616.2	-2.7%
Feb	519.1	548.4	-5.3
Mar	463.9	389.5	+19.1
Apr	446.5	402.2	+11.0
May	588.2	535.0	+9.9
Jun	829.1	824.8	+0.5
Jul	1002.3	970.0	+3.3
Aug	1004.6	970.0	+3.6
Sep	754.3	804.1	-6.2
Oct	486.8	616.2	-21.0
Nov	422.0	471.6	-10.5
Dec	541.6	569.7	-4.9
Year	7657.7	7717.7	-0.8

Source: Unpublished Bill-Frequency Distributions supplied by TUEC.

3.2.2 Hourly Load Shapes

Hourly load shapes for the summer and winter peak days in 1981 were compared with model estimates. While we did not have a full weather tape for the year, we obtained hourly temperature readings (dry- and wet-bulb) from TUEC for these two days. We then calibrated total residential sales each day to the area under the TP&L hourly residential load curve. The model, driven by hourly temperatures, apportioned the energy. A fraction of the annual UEC of the non-weather-sensitive end-uses is assigned to the day, according to the season. Hourly loads are apportioned according to their daily load profiles. The space conditioning electricity consumption is calculated as the residual (total minus sum of non-weather-sensitive energy use). Then the relative electricity load for space conditioning each hour is obtained from the time/temperature matrix.

This approach is limited, compared to the usual method of comparing a model backcast using a full year of actual weather since, in the single day comparison, the space conditioning energy is determined as the residual, dependent on all the non-weather-sensitive UEC's and load profiles. With a full year of data, the space conditioning UEC's can be estimated independently.

Figure 3-1 shows the results for the winter peak day. The model produced a bimodal curve with peaks at 8AM and 7PM. The actual curve is also bimodal, but with a much larger morning peak. The model shows that heating dominates the load shape. Given the use of proxy unit energy consumption data, not from the utility being modeled, it is difficult to draw strong conclusions about the model performance. Thermostat settings were not adjusted to improve the fit between model estimates and reported load curves.

Figure 3-2 shows that the summer peak day profile from the model gives better agreement with actual. The summer profile shows a single peak late in the day (6PM). The model shows a single peak at 7PM, slightly below the magnitude of the actual peak. The model disaggregation by end-use indicates that cooling comprises nearly 75% of the summer load.

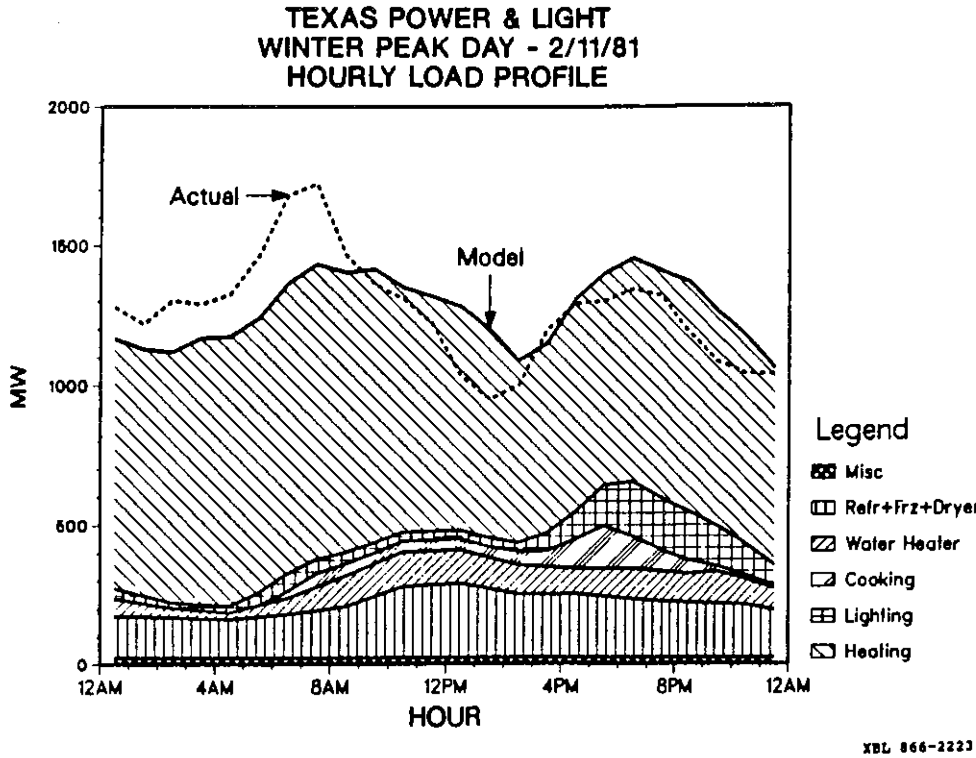

Figure 3.1 Comparison of predicted winter peak day load shape with TP&L recorded data.

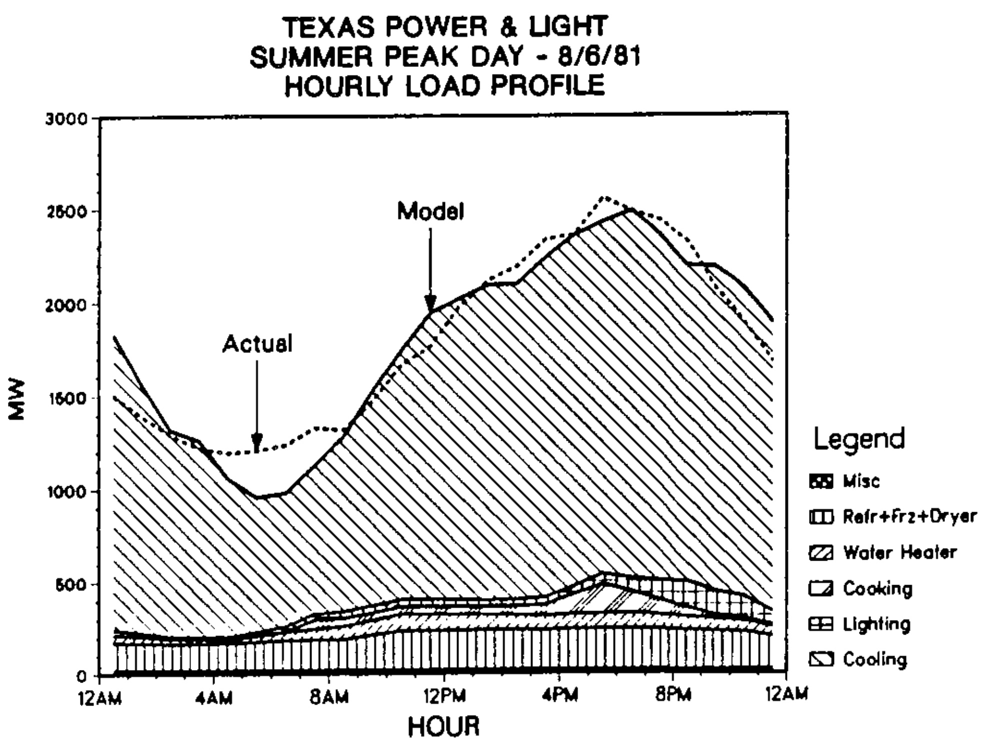

Figure 3.2 Comparison of predicted summer peak day load shape with TP&L recorded data.

3.3 LOAD SHAPE IMPACTS

We used the LBL models to forecast the load shape impacts of three levels of mandatory efficiency standards for new residential appliances. The levels called for by the standards were reviewed in Section 2.2. Briefly, they are a modest standard applied to all end-uses, Level 8; this same standard with a higher level efficiency for central air conditioners, Level 8/12; and a standard singling out only space cooling appliances (room and central air conditioners), Level 12/AC. In this section, we describe the load shape impacts of these standards on residential loads in the Texas Power & Light service territory of the Texas Utilities Electric Company.

In the base case, we expect TP&L residential electricity sales to grow from 9,520 GWh in 1987 to 12,900 GWh in 1996 (see Figure 3-3). The Level 8 and Level 12/AC standards produce similar reductions in sales growth, to about 12,100 and 11,900 GWh, respectively. The Level 8/12 standard reduces sales in 1996 to 11500 GWh.

Examination of the projected peak demand gives a different picture of the effects of the policies (see Figure 3-4). In the base case, we expect TP&L residential peak demand to grow from 2,630 MW in 1987 to over 3,450 MW in 1996. Level 8 standards reduce the 1996 peak to 3,180 MW. The Level 12/AC standard, while saving slightly more electricity than the Level 8 standard, reduces load growth about twice as much, to about 2,950 MW in 1996. The Level 8/12 standard achieves a slight additional decrease in load growth from the Level 12/AC standard of 2,880 MW.

Average sales per customer are expected to decline slightly over time in the base case (see Figure 3-5). The decrease is due to increasing equipment efficiency and tighter building shells. Implementation of the Level 8 and Level 12/AC standards reduces sales per customer in 1996 by an additional 6.4% and 8% to 10,900 and 10,700 kWh/customer, respectively. The Level 8/12 standard reduces per customer sales to about 10,300 kWh per customer in 1996.

The seasonal nature of sales reductions due to the standards analyzed is shown in Figure 3-6. For all cases, sales are reduced more in the summer months than in other months. The Level 8 standards reduce sales approximately 3% in winter and 8% in summer. With Level 12/AC standards, sales are slightly increased in winter (due to decreased investment in thermal integrity improvements),* but are reduced nearly 14% in summer. With Level 8/12 standards, winter sales are reduced about 3%, and summer sales are reduced 17%.

The effects on the hourly residential load shape for the peak summer day of 1996 are shown in Figure 3-7. The magnitude of peak savings increases from General standards to Stringent AC-only standards, to Combined standards. The reduction in off-peak load also occurs in the same order, but with smaller differences among the cases in off-peak periods.

*The LBL Energy Forecasting Model includes interaction between thermal integrity measures and appliance efficiency improvements. The model minimizes the life-cycle cost of homes based on market discount rates, fuel prices, and engineering/economic cost vs. energy-use curves for both appliances and thermal integrity measures.

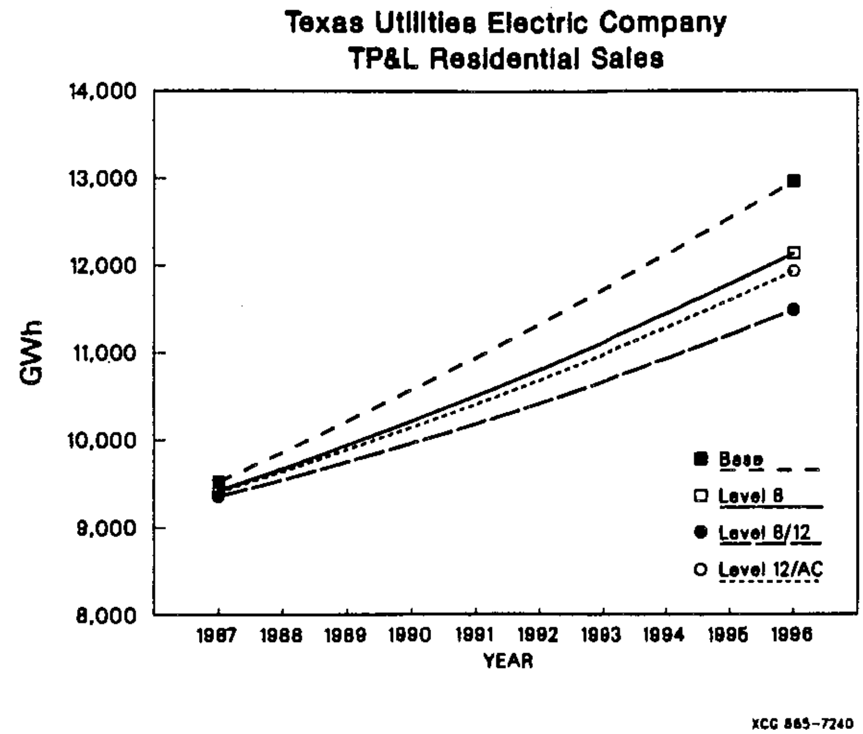

Figure 3.3 LBL forecasts of annual sales for the TP&L residential class.

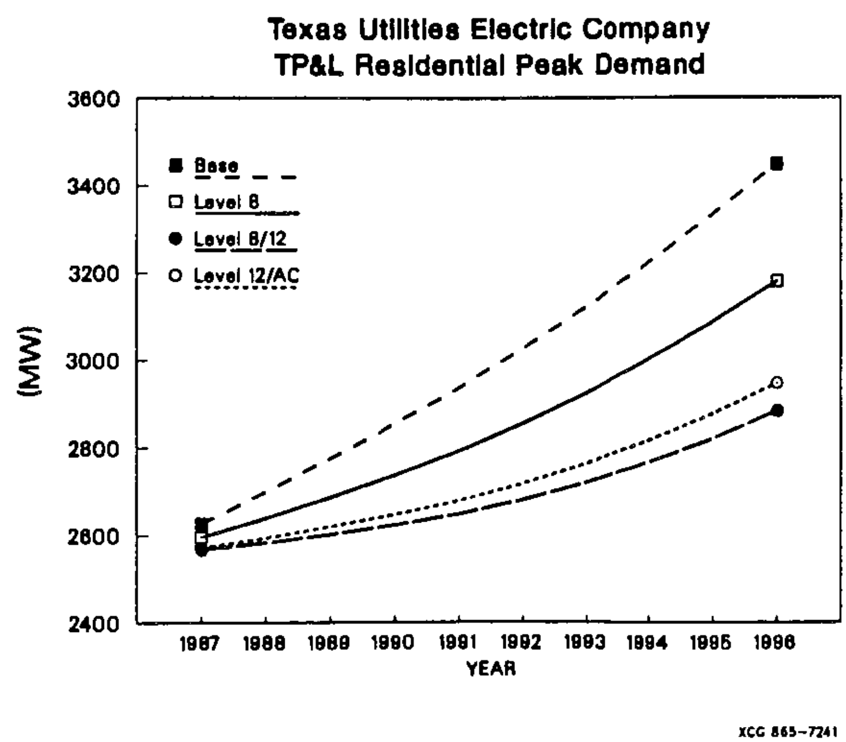

Figure 3.4 LBL forecasts of peak demands for the TP&L residential class.

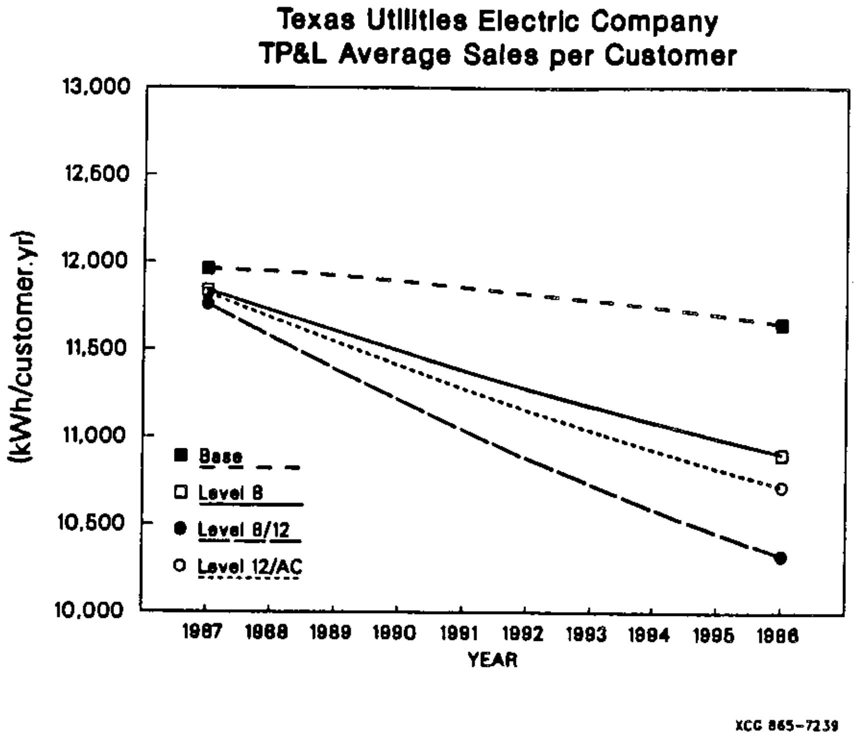

Figure 3.5 LBL forecasts of average annual sales per customer for the TP&L residential class.

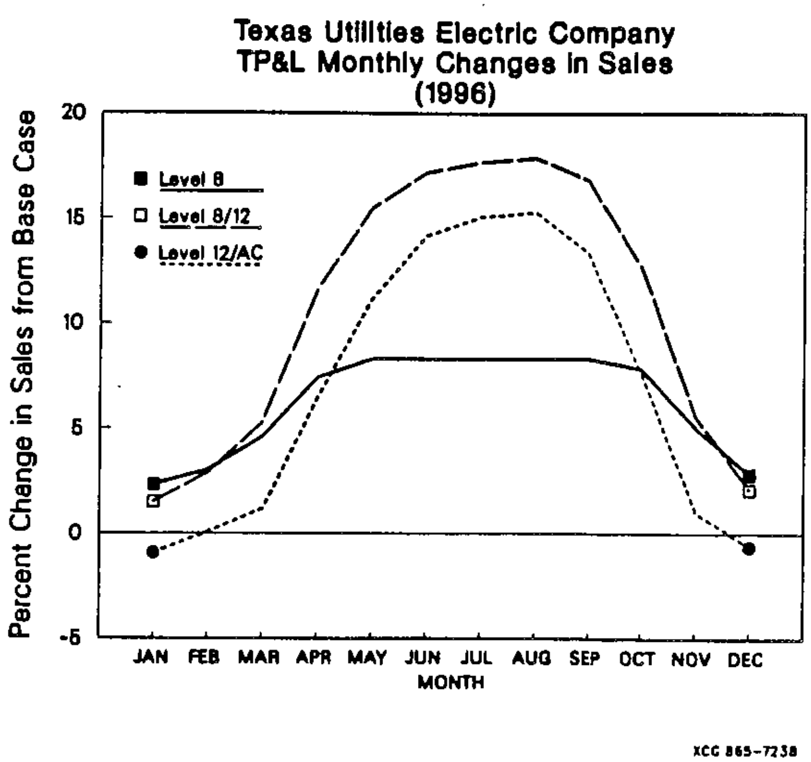

Figure 3.6 LBL forecasts of monthly changes in sales for the TP&L residential class.

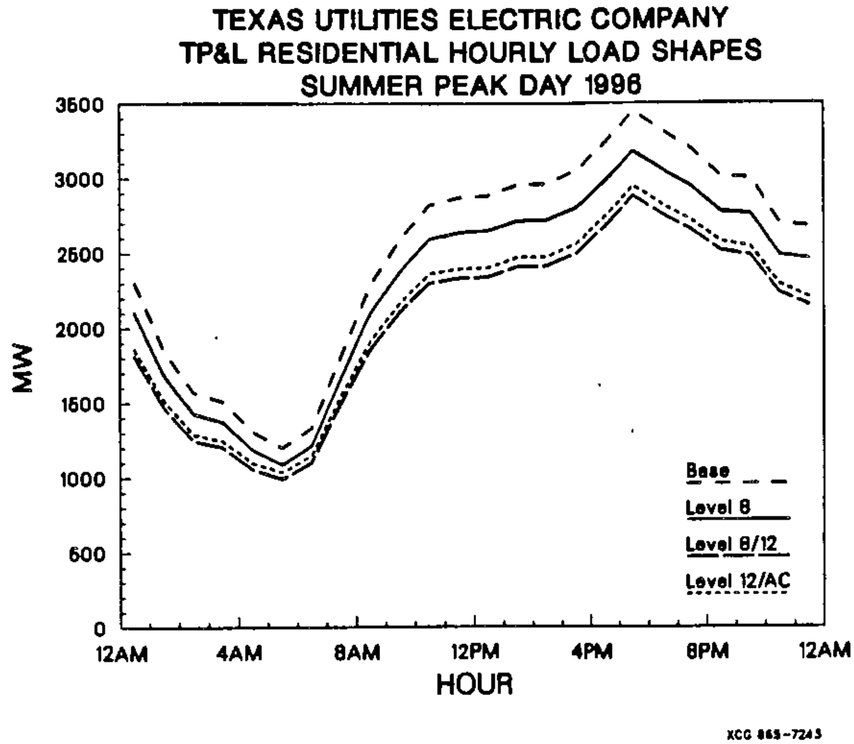

Figure 3.7 LBL forecasts of the 1996 summer peak day for the TP&L residential class.

4. FINANCIAL IMPACTS OF LOAD SHAPE CHANGES

The previous section documented the calculation of the load shape impacts for three sets of residential appliance efficiency standards. This section describes the procedures and assumptions used to evaluate the financial consequences of these impacts. We consider both a ratepayer and societal perspective these evaluations.

In both perspectives, the fundamental metric is the relationship between the benefits and costs to the ratepayer or society. The distinction between the two perspectives lies in the definition of the benefits, costs and time value of money. Our evaluation builds upon the general methods developed in earlier LBL utility case studies (Kahn, 1984). Figure 4-1 illustrates the flows of information between the various models and the quantities calculated.

The benefits of efficient appliances are the expenses avoided by utility through reduced electricity generation. For the load shape changes resulting from minimum appliance efficiency standards, these benefits must capture both short- and long-run avoided electricity generation expenses. In the short-run, capacity expansion decisions are fixed and so the benefits from reduced electricity sales are simply the variable costs of generation avoided. In the long-run, sufficiently large reductions in electricity sales will alter a previously optimal capacity expansion plan. At a minimum, the on-line date for future plants may be delayed, in the limit they be cancelled altogether. The value of this alteration in the supply plan must be incorporated in an assessment of the benefits from reduced electricity sales.

For the TUEC case study, we developed two methods for calculating avoided production cost benefits. Both were based on data supporting filings by the company to purchase power from small power producers and cogenerators. Our discussion of these methods is presented in Section 4.1. In Section 4.2, we summarize the avoided production cost benefits.

LBL Integrated Conservation Policy Analysis Method

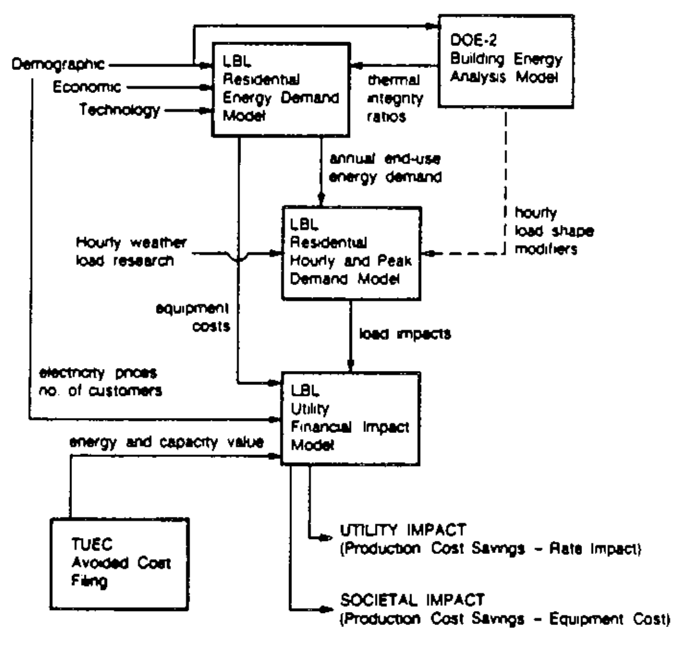

Figure 4-1 LBL Integrated Conservation Policy Analysis Method.

The cost to the ratepayer is the foregone recovery of the fixed-cost component of rates. That is, rates designed to recover the revenue requirement will, given a projected level of sales, under-recover this requirement since less electricity will be sold. These foregone or "lost" revenues must be recovered from ratepayers. We call this term the rate impact cost.

The rate impact cost requires calculation of both total revenues "lost" through reduced electricity sales and the variable cost component of these revenues. By subtraction, the difference between these two is the fixed-cost component of revenues that is foregone. The calculation of total lost revenues features the use of the block-adjustment method to account for tier-specific revenue losses. These calculations and the resulting ratepayer impacts are described in section 4.3.

The cost to society is the incremental cost of more efficient appliances. These costs are calculated directly by the LBL Residential Energy Demand Model. We present these costs and the resulting societal impacts in section 4.4.

4.1 AVOIDED PRODUCTION COSTS

An immediate consequence of improved appliance efficiencies is reduced demand for electricity and consequently reduced production costs. In the short-run, these reductions are in the form of avoided fuel and variable operating costs. In the long-run, these reductions can include capital cost savings from avoided or deferred plant investments.

We have based our analysis of these avoided costs on filings by TUEC for the purchase of power from small power producers and cogenerators. In doing so, we imply that a direct analogy exists between the load shape changes of appliance efficiency improvements and the load shape changes resulting from off-system generation of electricity. That is, from the standpoint of a utility generating system, both represent a reduction in demand for electricity.

Offers by electric utilities to purchase power exhibit substantial differences, both in terms of the economic framework embodied (short- vs. long-run) and in terms of implementation (rate design). For the TUEC case study, we developed two procedures for applying company-sponsored offers to purchase power to the valuation of load shape changes. The first followed a literal interpretation of the terms and provisions approved by the Texas Public Utilities Commission for payments to small power producers and cogenerators (TUEC, 1985). We will refer to this method as the TUEC avoided-cost methodology or TUEC method. The second took the cost data supporting the development of the State-approved offers and applied them in a manner more akin to those used in the case study of the Nevada Power Company. We will refer to this method as the energy-related capital avoided-cost methodology or ERC method. The logic underlying both methodologies is described more fully in Kahn, 1986b.

4.1.1 TUEC Avoided-Cost Methodology

TUEC offers to purchase power from small power producers and cogenerators are based on the cost savings resulting from a hypothetical two year deferral of the Forest Grove 1 generating plant scheduled to go on-line in 1989. Two quantities are calculated, an avoided fuel component and an avoided capital component. The fuel component is just the price of the avoided fuel (in this case, coal) times the average heat rate of the plant. Table 4-1 summarizes these values. All figures in this Table have been discounted to 1985 present value dollars using the Texas Utilities Electric Company rate of disadvantage, 11.5%.

Table 4-1. TUEC Coal Fuel Progression Stream

Year	Coal Fuel (mills/kWh)	Year	Coal Fuel (mills/kWh)
1989	14.9	2004	6.0
1990	14.0	2005	5.7
1991	13.2	2006	5.4
1992	12.4	2007	5.0
1993	11.7	2008	4.8
1994	11.0	2009	4.5
1995	10.4	2010	4.2
1996	9.8	2011	4.0
1997	9.2	2012	3.7
1998	8.7	2013	3.5
1999	8.2	2014	3.3
2000	7.7	2015	3.1
2001	7.2	2016	2.9
2002	6.8	2017	2.8
2003	6.4	2018	2.6

To calculate the capital component, the TUEC method compares the annual revenue requirements for the plant for two on-line dates, 1989 and 1991, and takes the difference to be the value of the deferral. A small amount is also subtracted from the difference to account for irreversible costs associated with such a deferral.

TUEC discounts the annual differences to a single quantity and then re-spreads it smoothly over time with an economic carrying charge that escalates at 7.07 percent annually. TUEC calls these values a Progression Stream. The present value of the original annual differences in revenue requirements and the new escalating Progression Stream are identical. Present-values are calculated using the TUEC rate of disadvantage. The rate of disadvantage is defined as the weighted average cost of capital reduced by the corporate tax rate times the debt component (Brealy, 1984). The progression stream values are presented in Table 4-2. Once again, all figures have been discounted to 1985 present value dollars using the Texas Utilities Electric Company's rate of disadvantage, 11.5%.

Table 4-2. TUEC Progression Streams

Year	Coal Plant Proxy ($/kW)	CT Proxy ($/kW)	Energy-Related Capital ($/kW)
1989	99.8	29.9	70.0
1990	95.9	28.7	67.2
1991	92.0	27.5	64.5
1992	88.4	26.4	61.9
1993	84.9	25.4	59.5
1994	81.5	24.4	57.1
1995	78.2	23.4	54.8
1996	75.1	22.5	52.6
1997	72.1	21.6	50.5
1998	69.2	20.7	48.5
1999	66.5	19.9	46.6
2000	63.8	19.1	44.7
2001	61.3	18.4	42.9
2002	58.9	17.6	41.2
2003	56.5	16.9	39.6
2004	54.3	16.3	38.0
2005	52.1	15.6	36.5
2006	50.0	15.0	35.0
2007	48.0	14.4	33.6
2008	46.1	13.8	32.3
2009	44.3	13.3	31.0
2010	42.5	12.7	29.8
2011	40.8	12.2	28.6
2012	39.2	11.8	27.5
2013	37.6	11.3	26.4
2014	36.1	10.8	25.3
2015	34.7	10.4	24.3
2016	33.3	10.0	23.3
2017	32.0	9.6	22.4
2018	30.7	9.2	21.5
Total	1766.1	528.9	1237.3

TUEC develops payments by relating the progression stream values to the start date and length of a contract. For example, a twelve year contract starting in 1993 would receive the corresponding twelve progression stream values, starting in 1993. By contrast, a 3 year contract starting in 1987 would receive only the 1989 progression stream value; according to the TUEC method, there is no avoided capital before the deferral date.

TUEC predicates receipt of the payments on a performance criterion, which requires that the small power producer or cogenerator have an annual average capacity factor of at least 65% and an average capacity factor of 75% in the summer months. TUEC defines the summer months to be June through September.

The performance criterion for the TUEC method implies that the small power producer or cogenerator must operate as though they are base-load power plants to receive the payments derived from this proxy. The implication is that the generation requirements of the utility are base-load in nature. It is also important to recognize a capacity- or reliability-related value for purchases of power. We combine these two concepts in the second avoided cost methodology.

4.1.2 Energy-Related Capital Avoided Cost Methodology

The ERC method differs from the TUEC method by distinguishing two categories of investment within the capital component. The decision to built a new plant is motivated by two considerations. On the one hand, a utility chooses to build coal plants because there are fuel savings associated with the investment. We call this aspect of the investment the energy-related capital component. On the other, building another plant also means that the reliability of the system will be enhanced. We call this aspect of the investment the capacity- or reliability-related capital component.

We approximated the division between these two functional components of the investment decision by calculating the revenue requirements for a combustion turbine and expressing the costs as a progression stream analogous to the one used by the TUEC method for a coal plant. We define the values in this progression stream to be the capacity-related capital component of the investment and the difference between the progression stream for the combustion turbine and the coal plant to be the energy-related capital component of the investment. The progression streams for the combustion turbine and the energy-related capital component are summarized in Table 4-2. The development of the combustion turbine progression stream is presented in Table 4-3.

Table 4-3. Revenue Requirements for Combustion Turbine Proxy

Year	Rate Base ($/kW)	Depreciation ($/kW)	Required Return ($/kW)	Revenue Requirement ($/kW)	Present Value ($/kW)
1989	422.1	14.1	98.1	112.2	72.6
1990	408.1	14.1	94.9	108.9	63.2
1991	394.0	14.1	91.6	105.7	55.0
1992	379.9	14.1	88.3	102.4	47.8
1993	365.9	14.1	85.0	99.1	41.5
1994	351.8	14.1	81.8	95.8	36.0
1995	337.7	14.1	78.5	92.6	31.2
1996	323.6	14.1	75.2	89.3	27.0
1997	309.6	14.1	72.0	86.0	23.3
1998	295.5	14.1	68.7	82.8	20.1
1999	281.4	14.1	65.4	79.5	17.3
2000	267.4	14.1	62.2	76.2	14.9
2001	253.3	14.1	58.9	73.0	12.8
2002	239.2	14.1	55.6	69.7	11.0
2003	225.1	14.1	52.3	66.4	9.4
2004	211.1	14.1	49.1	63.1	8.0
2005	197.0	14.1	45.8	59.9	6.8
2006	182.9	14.1	42.5	56.6	5.8
2007	168.9	14.1	39.3	53.3	4.9
2008	154.8	14.1	36.0	50.1	4.1
2009	140.7	14.1	32.7	46.8	3.4
2010	126.6	14.1	29.4	43.5	2.9
2011	112.6	14.1	26.2	40.2	2.4
2012	98.5	14.1	22.9	37.0	2.0
2013	84.4	14.1	19.6	33.7	1.6
2014	70.4	14.1	16.4	30.4	1.3
2015	56.3	14.1	13.1	27.2	1.0
2016	42.2	14.1	9.8	23.9	0.8
2017	28.1	14.1	6.5	20.6	0.6
2018	14.1	14.1	3.3	17.3	0.5
Total				528.9	

CT cost (1984 dollars) = 300 $/kW
inflation rate = 7.07 %/yr
fixed charge rate = 0.2325

Depreciation = Straight Line
Required Return = Rate Base * Fixed Charge Rate
Revenue Requirement = Required Return + Depreciation

4.1.3 Valuation of Load Shape Changes

To apply these costs to the load shape changes calculated earlier, definitions of the timing and lifetime of the efficient appliances and the measure of capacity value were required.

Our calculations all began with the incremental change in energy and demand for each year of the program, 1987 through 1996. To each increment of change we assumed a twelve year lifetime. While there is some ambiguity over the definition of the precise lifetime of a standard that mandates efficient appliances, twelve years is a conservative assumption since it corresponds to the lifetime of the least long-lived of the appliances, central air conditioners. With this assumption, we proceeded to value the incremental load shape changes as twelve year contracts to sell power to the utility.

Separate measures of the capacity avoided by the load shape changes were calculated for each valuation method. For the TUEC method, we imposed TUEC's performance requirements upon the energy saved by our appliance standards to derive imputed capacity values. Imputations were made for the summer and average annual performance criteria. In addition, the actual peak summer hour change in demand was also considered and the lowest of the three values was used. The latter term was a check to ensure that a standard with a particularly high load factor would not exceed the actual peak load impact due to the TUEC performance criterion. For the ERC method, we took the differences between the average of the highest 500 hourly loads as our measure of capacity value. All capacity values were then weighted up by an assumed system loss (6.0 percent) and reserve margin factor (20.0 percent). Tables 4-4,5,6 summarize for each policy case the annual values for each these measures of capacity benefit.

On these tables all savings are expressed as increments of change in load from the previous year. Highest average load is the average change in load for the highest 500 hourly loads. Annual average load is the capacity implied by the energy savings using a 65% capacity factor. Summer average load is the capacity implied by the summer season energy savings using a 75% capacity factor. For the TUEC avoided cost method, the capacity savings of the policy case is the lesser of these three measures of capacity savings. For the energy-related capital avoided cost method, the highest average load is the capacity savings. Transmission and distribution losses, and reserve margin allowances are not included.

Table 4-4. Capacity Savings for Load Shape Changes - Level 8 Appliance Standards, All End-Uses

Year	Base Case Peak Hour (MW)	Policy Case Peak Hour (MW)	Peak Hour Delta (MW)	Highest Avg. Load Savings (MW)	Annual Avg. Load Savings (MW)	Summer Avg. Load Savings (MW)	Capacity Savings (MW)
1987	2627.0	2595.1	31.9	27.3	16.9	24.5	16.9
1988	2700.3	2638.9	61.4	25.2	15.5	22.7	15.5
1989	2776.6	2686.4	90.2	24.4	15.1	22.1	15.1
1990	2855.4	2737.0	118.4	23.6	14.9	21.9	14.9
1991	2938.2	2792.2	146.0	22.7	14.6	21.3	14.6
1992	3027.0	2854.4	172.6	21.5	14.3	20.9	14.3
1993	3122.5	2924.3	198.2	20.5	13.9	20.1	13.9
1994	3224.7	3001.6	223.1	20.0	13.8	19.7	13.8
1995	3333.4	3086.3	247.1	19.1	13.3	19.0	13.3
1996	3448.2	3179.0	269.2	17.8	12.7	17.8	12.7

Table 4-5. Capacity Savings for Load Shape Changes - Level 12 Cooling End-Uses, Level 8 Others

Year	Base Case Peak Hour (MW)	Policy Case Peak Hour (MW)	Peak Hour Delta (MW)	Highest Avg. Load Savings (MW)	Annual Avg. Load Savings (MW)	Summer Avg. Load Savings (MW)	Capacity Savings (MW)
1987	2627.0	2566.1	60.9	55.2	28.3	47.0	28.3
1988	2700.3	2582.1	118.2	51.7	26.3	44.4	26.3
1989	2776.6	2601.4	175.2	50.4	26.0	44.3	26.0
1990	2855.4	2622.7	232.7	49.6	26.0	44.8	26.0
1991	2938.2	2647.8	290.4	48.2	26.0	44.9	26.0
1992	3027.0	2679.7	347.3	45.9	25.7	44.4	25.7
1993	3122.5	2719.0	403.5	43.4	25.5	44.0	25.5
1994	3224.7	2765.1	459.6	42.4	25.5	44.0	25.5
1995	3333.4	2818.5	514.9	40.9	25.1	43.3	25.1
1996	3448.2	2881.8	566.4	38.1	23.6	40.5	23.6

Table 4-6. Capacity Savings for Load Shape Changes - Level 12 Standards, Cooling End-Uses only

Year	Base Case Peak Hour (MW)	Policy Case Peak Hour (MW)	Peak Hour Delta (MW)	Highest Avg. Load Savings (MW)	Annual Avg. Load Savings (MW)	Summer Avg. Load Savings (MW)	Capacity Savings (MW)
1987	2627.0	2572.7	54.3	48.9	19.8	39.6	19.8
1988	2700.3	2595.1	105.2	45.9	18.5	37.3	18.5
1989	2776.6	2620.6	156.0	44.8	18.4	37.3	18.4
1990	2855.4	2648.1	207.3	44.0	18.5	37.8	18.5
1991	2938.2	2679.6	258.6	42.9	18.5	37.7	18.5
1992	3027.0	2717.9	309.1	40.6	18.1	37.2	18.1
1993	3122.5	2763.8	358.7	38.5	17.8	36.6	17.8
1994	3224.7	2816.5	408.2	37.5	17.8	36.5	17.8
1995	3333.4	2876.6	456.8	36.5	17.5	35.8	17.5
1996	3448.2	2946.5	501.7	33.7	16.0	32.9	16.0

For load shape changes prior to 1989 (the original start date of the deferred plant), we followed TUEC practice by not assigning capital cost benefits. We did, however, assign avoided fuel benefits since short-run fuel savings will result from avoided electricity generation. We assumed oil and gas were the marginal fuels for the system, a system average marginal heat rate of 10,000 Btu/kWh, and the DRI price series for utility purchases of natural gas (starting at 3.468 dollars/MBtu in 1985) to calculate avoided fuel savings for 1987 and 1988 (DRI, 1985). We used the same system loss factor (6.0 percent) to convert our residential class loads to system avoided loads. Table 4-7 contains LBL's estimates of TUEC short-run marginal costs. Short-run marginal costs are the product of an assumed incremental heat rate of 10,000 Btu/kWh and the Summer, 1985 DRI price series for the cost of natural gas to electric utilities. The table contains values extending beyond 1988 since short-run marginal costs are also a component of the calculation of ratepayer costs. All values have been discounted to 1985 present value dollars using the TUEC rate of disadvantage, 11.5%.

Table 4-7. TUEC Short-Run Marginal Cost Estimates

Year	Marginal Cost (mills/kWh)	Year	Marginal Cost (mills/kWh)
1987	27.7	1998	21.4
1988	25.9	1999	20.9
1989	24.5	2000	20.5
1990	23.3	2001	20.0
1991	23.2	2002	19.5
1992	23.0	2003	19.1
1993	22.9	2004	18.6
1994	22.8	2005	18.2
1995	22.7	2006	17.8
1996	22.5	2007	17.4
1997	22.0	2008	16.9

4.2 AVOIDED PRODUCTION COST BENEFITS

Tables 4-8,9,10 summarize the avoided production cost calculations for each policy case using the TUEC avoided cost methodology. Tables 4-8a,9a,10a summarize the same costs using the energy related capital methodology. For all our calculations, we continued to use the TUEC rate of disadvantage, 11.5 percent, to discount our results and express them in 1985 dollars.

The format of each table is as follows. For each year, the tables present the total change in energy and capacity value, as defined by the particular avoided cost methodology. Because the valuation methods are based on a hypothetical twelve year contract to sell power to the utility, the next column lists the incremental changes upon which the hypothetical contract is based. The following column lists the 1985 present value of avoiding the increment for twelve years. This column is followed by the per unit value, in 1985 present value dollars per kWh, of the avoided increment. A final set of columns sums the two components and expresses the total avoided production cost benefit and its per unit value.

Across policy cases, the greatest avoided production cost benefits are conferred by the policy case that saves the most energy, Level 8/12. Of more importance for our later calculation of ratepayer and societal impacts, however, are the per unit values of the load shape impacts. In this respect, we observe that the standard targeting summer peak demands, Level 12/AC, has the highest per unit value. It is easy to see that, given two policies that save similar amounts of energy, Level 8 and Level 12/AC, the one that saves more capacity will have a higher value.

For each policy case, the energy-related avoided cost methodology produces larger savings relative to the TUEC avoided cost methodology. Comparing the component unit values between policy cases illustrates the cause. As expected, the TUEC method places the bulk of the value for load shape changes in the capacity term. That is, since the TUEC method bases capacity value on a performance requirement derived from a coal plant proxy, our policy cases that target peak loads are valued at far less than their maximum impact on peak demand.

The significance of the performance criteria of the TUEC avoided cost methodology is that it tends to obviate the differences in the load shape impacts of the policies. That is, since the energy delivered is really the dominant term in the equation, the actual demand impacts are suppressed. This feature of the methodology is best seen by examination of the total per unit values. Between policy cases, the total per unit values are nearly identical, despite very different impacts on system peak loads. By comparison, the same values for the ERC methodology do capture these impacts of the policy cases, even though these differences are still small.

Table 4-8. Avoided Production Costs - Level 8 Appliance Standards, All End-Uses
Texas Utilities Electric Company

TUEC Avoided Cost Methodology

	Energy				Capacity				Total	
Year	Total (GWh)	Increment (GWh)	Total (M$)	($/kWh)	Total (MW)	Increment (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	96.1	96.1	16.9	0.176	16.9	16.9	18.0	0.187	34.8	0.363
1988	184.5	88.4	13.8	0.156	32.4	15.5	17.8	0.202	31.7	0.358
1989	270.7	86.2	12.0	0.139	47.5	15.1	18.6	0.216	30.6	0.355
1990	355.3	84.6	11.0	0.130	62.4	14.9	17.6	0.208	28.6	0.338
1991	438.6	83.3	10.2	0.123	77.0	14.6	16.6	0.199	26.8	0.322
1992	519.9	81.3	9.4	0.116	91.3	14.3	15.6	0.191	24.9	0.307
1993	599.3	79.4	8.7	0.109	105.3	13.9	14.6	0.184	23.3	0.293
1994	678.0	78.7	8.1	0.103	119.1	13.8	13.9	0.176	22.0	0.279
1995	754.0	76.0	7.3	0.096	132.4	13.3	12.9	0.169	20.2	0.266
1996	826.3	72.3	6.6	0.091	145.1	12.7	11.8	0.163	18.3	0.254
Total		826.3	104.0	0.126			157.2	0.190	261.2	0.316

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). See tables 4-1 and 4-2 for the components of these values. See table 4-4 for the determination of capacity value.

Table 4-9. Avoided Production Costs - Level 12 Cooling End-Uses, Level 8 All Others
Texas Utilities Electric Company

TUEC Avoided Cost Methodology

	Energy				Capacity				Total	
Year	Total (GWh)	Increment (GWh)	Total (M$)	($/kWh)	Total (MW)	Increment (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	160.9	160.9	28.2	0.176	28.3	28.3	30.1	0.187	58.3	0.363
1988	310.7	149.8	23.4	0.156	54.6	26.3	30.2	0.202	53.6	0.358
1989	458.9	148.2	20.6	0.139	80.6	26.0	32.0	0.216	52.6	0.355
1990	606.8	147.9	19.3	0.130	106.6	26.0	30.7	0.208	50.0	0.338
1991	755.0	148.2	18.2	0.123	132.6	26.0	29.5	0.199	47.8	0.322
1992	901.3	146.3	16.9	0.116	158.3	25.7	28.0	0.191	44.9	0.307
1993	1046.6	145.3	15.9	0.109	183.8	25.5	26.7	0.184	42.6	0.293
1994	1192.0	145.4	15.0	0.103	209.3	25.5	25.6	0.176	40.6	0.279
1995	1334.8	142.8	13.8	0.096	234.4	25.1	24.2	0.169	38.0	0.266
1996	1469.4	134.6	12.3	0.091	258.1	23.6	21.9	0.163	34.2	0.254
Total		1469.4	183.5	0.125			279.0	0.190	462.5	0.315

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). See tables 4-1 and 4-2 for the components of these values. See table 4-5 for the determination of capacity value.

Table 4-10. Avoided Production Costs - Level 12 Standards, Cooling End-Uses Only
Texas Utilities Electric Company

TUEC Avoided Cost Methodology

	Energy				Capacity				Total	
Year	Total (GWh)	Increment (GWh)	Total (M$)	($/kWh)	Total (MW)	Increment (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	113.0	113.0	19.8	0.176	19.8	19.8	21.1	0.187	41.0	0.363
1988	218.6	105.6	16.5	0.156	38.4	18.5	21.3	0.202	37.8	0.358
1989	323.3	104.7	14.5	0.139	56.8	18.4	22.6	0.216	37.2	0.355
1990	428.8	105.5	13.8	0.130	75.3	18.5	21.9	0.208	35.6	0.338
1991	534.2	105.4	13.0	0.123	93.8	18.5	21.0	0.199	34.0	0.322
1992	637.3	103.1	11.9	0.116	111.9	18.1	19.7	0.191	31.6	0.307
1993	738.9	101.6	11.1	0.109	129.8	17.8	18.7	0.184	29.8	0.293
1994	840.5	101.6	10.4	0.103	147.6	17.8	17.9	0.176	28.4	0.279
1995	940.1	99.6	9.6	0.096	165.1	17.5	16.9	0.169	26.5	0.266
1996	1031.4	91.3	8.3	0.091	181.1	16.0	14.8	0.163	23.2	0.254
Total		1031.4	129.0	0.125			196.0	0.190	325.0	0.315

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). See tables 4-1 and 4-2 for the components of these values. See table 4-6 for the determination of capacity value.

Table 4-8a. Avoided Production Costs - Level 8 Appliance Standards, All End-Uses
Texas Utilities Electric Company

Energy-Related Capital Avoided Cost Methodology

Year	Energy				Capacity				Total	
	Total (GWh)	Increment (GWh)	Total (M$)	($/kWh)	Total (MW)	Increment (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	96.1	96.1	27.9	0.290	27.3	27.3	8.7	0.091	36.6	0.381
1988	184.5	88.4	24.8	0.280	52.5	25.2	8.7	0.098	33.5	0.378
1989	270.7	86.2	23.4	0.272	76.9	24.4	9.0	0.104	32.4	0.376
1990	355.3	84.6	21.8	0.258	100.5	23.6	8.3	0.099	30.2	0.357
1991	438.6	83.3	20.4	0.245	123.2	22.7	7.7	0.093	28.2	0.338
1992	519.9	81.3	19.0	0.233	144.7	21.5	7.0	0.086	26.0	0.319
1993	599.3	79.4	17.6	0.222	165.2	20.5	6.4	0.081	24.0	0.303
1994	678.0	78.7	16.6	0.211	185.2	20.0	6.0	0.076	22.6	0.287
1995	754.0	76.0	15.2	0.200	204.3	19.1	5.5	0.073	20.7	0.273
1996	826.3	72.3	13.8	0.191	222.1	17.8	4.9	0.068	18.7	0.259
Total		826.3	200.6	0.243			72.3	0.088	272.9	0.330

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). See tables 4-1 and 4-2 for the components of these values. See table 4-4 for the determination of capacity value.

Table 4-9a. Avoided Production Costs - Level 12 Cooling End-Uses, Level 8 All Others
Texas Utilities Electric Company

Energy-Related Capital Avoided Cost Methodology

	Energy				Capacity				Total	
Year	Total (GWh)	Increment (GWh)	Total (M$)	($/kWh)	Total (MW)	Increment (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	160.9	160.9	47.1	0.293	55.2	55.2	17.6	0.109	64.7	0.402
1988	310.7	149.8	42.4	0.283	106.9	51.7	17.8	0.119	60.1	0.401
1989	458.9	148.2	40.7	0.274	157.3	50.4	18.6	0.125	59.2	0.400
1990	606.8	147.9	38.6	0.261	206.9	49.6	17.5	0.119	56.1	0.379
1991	755.0	148.2	36.8	0.248	255.1	48.2	16.4	0.110	53.2	0.359
1992	901.3	146.3	34.5	0.236	301.0	45.9	15.0	0.102	49.5	0.338
1993	1046.6	145.3	32.6	0.225	344.4	43.4	13.6	0.094	46.2	0.318
1994	1192.0	145.4	31.1	0.214	386.8	42.4	12.8	0.088	43.8	0.301
1995	1334.8	142.8	29.0	0.203	427.7	40.9	11.8	0.083	40.8	0.286
1996	1469.4	134.6	26.0	0.193	465.8	38.1	10.6	0.078	36.6	0.272
Total		1469.4	358.7	0.244			151.5	0.103	510.2	0.347

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). See tables 4-1 and 4-2 for the components of these values. See table 4-6 for the determination of capacity value.

Table 4-10a. Avoided Production Costs - Level 12 Cooling End-Uses, Level 8 All Others
Texas Utilities Electric Company

Energy-Related Capital Avoided Cost Methodology

Year	Energy				Capacity				Total	
	Total (GWh)	Increment (GWh)	Total (M$)	($/kWh)	Total (MW)	Increment (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	113.0	113.0	33.4	0.296	48.9	48.9	15.6	0.138	49.0	0.434
1988	218.6	105.6	30.2	0.286	94.8	45.9	15.8	0.150	46.0	0.436
1989	323.3	104.7	29.1	0.278	139.6	44.8	16.5	0.158	45.6	0.436
1990	428.8	105.5	27.9	0.264	183.6	44.0	15.6	0.147	43.4	0.412
1991	534.2	105.4	26.5	0.251	226.5	42.9	14.6	0.138	41.1	0.390
1992	637.3	103.1	24.6	0.239	267.1	40.6	13.2	0.128	37.9	0.367
1993	738.9	101.6	23.1	0.228	305.6	38.5	12.1	0.119	35.2	0.346
1994	840.5	101.6	22.0	0.217	343.1	37.5	11.3	0.111	33.3	0.328
1995	940.1	99.6	20.5	0.206	379.6	36.5	10.5	0.106	31.0	0.312
1996	1031.4	91.3	17.9	0.196	413.3	33.7	9.3	0.102	27.3	0.298
Total		1031.4	255.3	0.248			134.5	0.130	389.8	0.378

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). See tables 4-1 and 4-2 for the components of these values. See table 4-2 for the determination of capacity value.

4.3 RATEPAYER IMPACTS

The introduction of efficient appliances cannot be achieved without costs. A comprehensive evaluation of the desirability of standards that mandate these efficiency levels requires that these costs be considered. From the ratepayer's perspective, these costs consist of rate increases needed to cover the portion of fixed costs that are no longer recovered by revenues. We will refer to this term as the rate impact cost of the appliance standards.

The rate impact cost of efficient appliances hinges ultimately on a theory of regulation. Since efficient appliances consume less electricity, a rate design that does not consider the load impact of these appliances will under-collect revenues. The impact on ratepayers will be less than the full amount of the "lost" revenues, since only the component of revenues designed to recover fixed costs or base-rate revenues will be lost; the variable-cost component will be avoided. In fact, not all of base-rate revenues may be lost, since the avoided variable-cost component is properly valued by the short-run marginal costs to the utility, not by the average variable-cost. Previously, we defined short-run marginal costs as the marginal fuel cost times a heat rate. In the following section, we will describe the development of lost revenues.

4.3.1 Lost Revenues

Lost revenues are essentially the change in sales between our base case and a given policy case times the average residential retail electricity rate. For TUEC the calculation is less straight-forward because TUEC residential class tariffs feature a declining block in the winter months. The complication is that, while there is a single price for sales in each tier, sales in each tier will change as total consumption changes. We adopt industry practice by applying the Block-adjustment procedure to estimate the impact of these changes on total revenues. The prices are an extrapolation of existing prices at the TUEC-projected escalation rate used by the LBL Residential Energy Model to forecast sales (see Section 3.1.6).

The Block-adjustment procedure uses an existing cumulative-sales-frequency distribution to calculate revenues but adjusts the tier boundaries to reflect differing levels of total sales. The specific adjustment varies tier boundaries in inverse proportion to mean levels of sales. Thus, an increase in sales (higher mean) would result in a lower tier boundary. A lower tier boundary results in a greater fraction of sales being valued at the price of the higher tier. This technique is described more fully in Kahn, 1984.

For TUEC, the effect of the applying the Block-adjustment technique on lost revenues is reduced by the magnitude of lost electricity sales in the summer. For lost sales in winter, Block-adjustment will tend to increase the lost revenue term vis-a-vis not using the Block-adjustment. Total lost revenues, however, will also be a function of the magnitude of lost sales in the summer, which are not Block-adjusted. If lost summer sales are great relative to lost winter sales, as expected in the Level 12/AC and Level 8/12 standards, the effects of Block-adjustment on total revenues will be reduced.

Several effects combine to produce this result. First, recall that we expect the policy that saves the most energy in the winter season (Level 8) to be relatively more costly in the winter months. TUEC expects average sales per customer to decline (see Section 3.3), and so block-adjusting places a larger fraction of winter sales in lower tiers. Since TUEC winter tariffs feature declining blocks, higher tiers are priced lower, and winter lost revenues increase on a per unit basis. The load shape changes, which further reduce average winter sales per customer, therefore, raise this value still higher. Against this, one must also consider summer season sales. Summer season sales are all valued at the price of the higher tier from the winter season and so, the winter season average revenues will be always be lower than those of the summer season. The impact on the winter season average revenue term on total revenue losses, then, will depend on the ratio of summer season savings to those in winter. For this reason, the policy with the greatest summer season savings relative to winter, Level 12/AC, yields the greatest per unit revenue loss.

Table 4-11 compares annual average per unit lost revenues over time for each policy case to the assumed tier prices. Average prices on this Table represent the annual average values of "lost" revenues. All prices have been discounted to 1985 dollars using the TUEC rate of disadvantage, 11.5%.

4.3.2 Rate Impact Cost

Three steps were required to apply the Block-adjusted lost revenues to the rate impact cost calculation. First, total revenues were calculated for both the base and policy case sales. Remember, the Block-adjustment relies on the changing mean of total monthly sales. Second, the differences in total revenues were re-expressed as per unit values for the lost revenues (see Table 4-11 for the single year values). Third, in keeping with the assumption of a twelve year lifetime for the standards, the present value of twelve years of the lost revenue were calculated from the annual per unit values.

Tables 4-12,13,14 summarize the rate impact costs for each policy case. Each table begins with the energy forecast for both the base and policy cases. After presenting the change in energy between the two cases, the incremental change is listed. As described above, the lost revenue term represents the 1985 present value of losing the increment of sales for twelve years. Similarly, the avoided variable cost is the 1985 present value of the short-run marginal cost saved by the avoided increment of energy. The rate impact is the difference between the lost revenue term and the avoided variable cost. The per unit values listed also represent the 1985 present values of avoiding the increment of sales for twelve years.

Comparing the per unit values on each table highlights the influence of the Block-adjustment method on the rate impact cost. The per unit revenue values for savings in 1987 range from $0.444 for Level 8 to $0.530 for Level 12/AC. Level 8 affects both summer and winter loads (see Figure 3-5) and so the effect of the winter block adjustment is greatest on that standard. As noted earlier, the Level 12/AC standard affects essentially only summer loads and is valued highest. The Level 8/12 standard affects both winter and summer loads but has a relatively greater impact in summer, consequently, the per unit value of the lost revenue falls between the two. The per unit value of avoided variable costs is unchanged in each policy case.

Table 4-11. TUEC Residential Retail Rates

	TUEC Tariff		Level 8	Level 8/12	Level 12/AC
Year	Tier 1 (mills/kWh)	Tier 2 (mills/kWh)	Average (mills/kWh)	Average (mills/kWh)	Average (mills/kWh)
1987	43.2	14.9	23.2	30.6	30.9
1988	44.0	15.2	30.1	35.1	37.0
1989	44.9	15.5	33.0	37.3	39.8
1990	45.8	15.8	34.9	38.9	41.6
1991	46.7	16.1	36.2	40.1	43.0
1992	47.7	16.4	37.4	41.3	44.4
1993	48.6	16.8	38.4	42.3	45.5
1994	49.6	17.1	39.3	43.4	46.6
1995	50.6	17.4	40.2	44.3	47.6
1996	51.6	17.8	41.0	45.2	48.6

Table 4-12. Rate Impact - Level 8 Appliance Standards, All End-Uses
Texas Utilities Electric Company

					A Lost Revenues		B Avoided Variable Cost		A - B Rate Impact	
Year	Base (GWh)	Policy (GWh)	Delta (GWh)	Increment (GWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	9516.6	9420.5	96.1	96.1	42.6	0.444	27.1	0.282	15.6	0.162
1988	9856.6	9672.1	184.5	88.4	41.6	0.470	24.3	0.275	17.2	0.195
1989	10210.4	9939.7	270.7	86.2	42.5	0.493	23.2	0.270	19.2	0.223
1990	10570.7	10215.4	355.3	84.6	43.6	0.516	22.4	0.265	21.2	0.251
1991	10939.2	10500.6	438.6	83.3	45.0	0.541	21.8	0.261	23.3	0.279
1992	11319.2	10799.3	519.9	81.3	46.2	0.568	20.9	0.257	25.3	0.311
1993	11712.2	11112.9	599.3	79.4	47.5	0.599	20.1	0.253	27.5	0.346
1994	12116.3	11438.3	678.0	78.7	49.8	0.632	19.5	0.248	30.2	0.384
1995	12528.7	11774.7	754.0	76.0	50.9	0.670	18.5	0.243	32.5	0.427
1996	12949.2	12122.9	826.3	72.3	51.5	0.712	17.2	0.238	34.3	0.474
Total				826.3	461.2	0.558	215.0	0.260	246.2	0.298

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Lost revenues were calculated using the projected TUEC retail rate schedule and the block-adjustment technique. Avoided variable costs were taken from table 4-7. Rate impact is the difference between revenues and avoided variable costs.

Table 4-13. Rate Impact - Level 12 Cooling End-Uses, Level 8 All Others
Texas Utilities Electric Company

					A Lost Revenues		B Avoided Variable Cost		A - B Rate Impact	
Year	Base (GWh)	Policy (GWh)	Delta (GWh)	Increment (GWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	9516.6	9355.7	160.9	160.9	79.7	0.495	45.4	0.282	34.3	0.213
1988	9856.6	9545.9	310.7	149.8	77.3	0.516	41.2	0.275	36.1	0.241
1989	10210.4	9751.5	458.9	148.2	79.3	0.535	40.0	0.270	39.3	0.265
1990	10570.7	9963.9	606.8	147.9	81.9	0.554	39.2	0.265	42.7	0.289
1991	10939.2	10184.2	755.0	148.2	85.0	0.574	38.7	0.261	46.3	0.312
1992	11319.2	10417.9	901.3	146.3	87.0	0.595	37.6	0.257	49.4	0.337
1993	11712.2	10665.6	1046.6	145.3	89.7	0.617	36.7	0.253	53.0	0.365
1994	12116.3	10924.3	1192.0	145.4	93.3	0.642	36.1	0.248	57.3	0.394
1995	12528.7	11193.9	1334.8	142.8	95.4	0.668	34.7	0.243	60.7	0.425
1996	12949.2	11479.8	1469.4	134.6	93.8	0.697	32.0	0.238	61.8	0.459
Total				1469.4	862.4	0.587	381.6	0.260	480.8	0.327

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Lost revenues were calculated using the projected TUEC retail rate schedule and the block adjustment technique. Avoided variable costs were taken from table 4-7. Rate impact is the difference between revenues and avoided variable costs.

Table 4-14. Rate Impact - Level 12 Standards, Cooling End-Uses Only
Texas Utilities Electric Company

Year	Base (GWh)	Policy (GWh)	Delta (GWh)	Increment (GWh)	A Lost Revenues Total (M$)	A Lost Revenues ($/kWh)	B Avoided Variable Cost Total (M$)	B Avoided Variable Cost ($/kWh)	A - B Rate Impact Total (M$)	A - B Rate Impact ($/kWh)
1987	9516.6	9403.6	113.0	113.0	59.9	0.530	31.9	0.282	28.0	0.248
1988	9856.6	9638.0	218.6	105.6	58.7	0.555	29.0	0.275	29.6	0.280
1989	10210.4	9887.1	323.3	104.7	60.5	0.578	28.2	0.270	32.3	0.308
1990	10570.7	10141.9	428.8	105.5	63.4	0.601	28.0	0.265	35.4	0.336
1991	10939.2	10405.0	534.2	105.4	65.9	0.625	27.5	0.261	38.3	0.363
1992	11319.2	10681.9	637.3	103.1	67.1	0.651	26.5	0.257	40.6	0.394
1993	11712.2	10973.3	738.9	101.6	69.0	0.679	25.7	0.253	43.3	0.426
1994	12116.3	11275.8	840.5	101.6	72.2	0.710	25.2	0.248	46.9	0.462
1995	12528.7	11588.6	940.1	99.6	74.1	0.744	24.2	0.243	49.9	0.501
1996	12949.2	11917.8	1031.4	91.3	71.3	0.781	21.7	0.238	49.6	0.543
Total				1031.4	661.9	0.642	268.0	0.260	394.0	0.382

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Lost revenues were calculated using the projected TUEC retail rate schedule and the block adjustment technique. Avoided variable costs were taken from table 4-7. Rate impact is the difference between revenues and avoided variable costs.

4.3.3 Ratepayer Impacts

Tables 4-15,16,17 summarize the ratepayer impacts for each policy case using the TUEC avoided cost methodology. Tables 4-15a,16a,17a summarize the ratepayer impacts using the energy related capital methodology. The format of each table is as follows. After summarizing the incremental energy and capacity components of the load shape changes, the avoided production cost benefits from the earlier tables are presented. These benefits are followed by the rate impact costs previously described. The final column presents the net benefit, which is the difference between the avoided production cost benefits and the rate impact costs.

The tables indicate that the choice of avoided cost methodology strongly influences the impact on ratepayers. Under the TUEC method, the Level 8 standard alone has positive impacts on ratepayers. Under the ERC method, both the Level 8 and Level 8/12 standards have positive impacts on ratepayers. Under either methodology, the rate impact costs are the same for each policy.

The year by year results point to the underlying forces driving these results. For either methodology and for every policy case, avoided cost benefits are initially high on a per unit basis but fall monotonically over time. The rate impact costs, conversely, start lower on a per unit basis but increase steadily over time. The two streams cross near 1992 (depending on the policy case) and thereafter, net benefits are negative. Our choice of 1996 as the ending date of our program has the effect of merely preventing the losses from increasing still further.

These results suggest that the value of the higher appliance efficiencies lies in their timing and that, for TUEC, the programs outlive their usefulness after four to six years.

Before turning to the calculation of societal costs, two comments on the regulatory assumptions built into our calculation of the rate impact cost are in order. Our earlier discussion of the rate impact cost indicates that the cost is driven by the lost revenue term; avoided variable costs are identical for each policy case. The lost revenue term is, in turn, a function of projected retail rates and, for winter sales, the block-adjustment procedure. Changes in future retail rates or the tiered structure of rates in the winter would modify these results. Our decision to project rates from TUEC information, consequently, deserves closer attention.

Finally, the decision to consider the rate impact as a cost to the ratepayer relies on an assumption of perfect regulation. In the absence of perfect regulation, the failure to recover costs through revenues will be a cost to the stockholders of the utility.

Table 4-15. Ratepayer Impact - Level 8 Appliance Standards, All End-Uses
Texas Utilities Electric Company

TUEC Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Rate Impact Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	96.1	16.9	34.8	0.363	15.6	0.162	19.3	0.201
1988	88.4	32.4	31.7	0.358	17.2	0.195	14.4	0.163
1989	86.2	47.5	30.6	0.355	19.2	0.223	11.4	0.132
1990	84.6	62.4	28.6	0.338	21.2	0.251	7.4	0.087
1991	83.3	77.0	26.8	0.322	23.3	0.279	3.6	0.043
1992	81.3	91.3	24.9	0.307	25.3	0.311	-0.3	-0.004
1993	79.4	105.3	23.3	0.293	27.5	0.346	-4.2	-0.053
1994	78.7	119.1	22.0	0.279	30.2	0.384	-8.3	-0.105
1995	76.0	132.4	20.2	0.266	32.5	0.427	-12.2	-0.161
1996	72.3	145.1	18.3	0.254	34.3	0.474	-15.9	-0.220
Total	826.3	145.1	261.2	0.316	246.2	0.298	15.0	0.018

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-8. Rate impact costs were taken from Table 4-12. Net benefit is the difference between the avoided cost benefit and the rate impact cost.

Table 4-16. Ratepayer Impact - Level 12 Cooling End-Uses, Level 8 All Others
Texas Utilities Electric Company

TUEC Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Rate Impact Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	160.9	28.3	58.3	0.363	34.3	0.213	24.0	0.149
1988	149.8	54.6	53.6	0.358	36.1	0.241	17.5	0.117
1989	148.2	80.6	52.6	0.355	39.3	0.265	13.3	0.090
1990	147.9	106.6	50.0	0.338	42.7	0.289	7.3	0.049
1991	148.2	132.6	47.8	0.322	46.3	0.312	1.5	0.010
1992	146.3	158.3	44.9	0.307	49.4	0.337	-4.5	-0.031
1993	145.3	183.8	42.6	0.293	53.0	0.365	-10.4	-0.072
1994	145.4	209.3	40.6	0.279	57.3	0.394	-16.7	-0.115
1995	142.8	234.4	38.0	0.266	60.7	0.425	-22.8	-0.159
1996	134.6	258.1	34.2	0.254	61.8	0.459	-27.6	-0.205
Total	1469.4	258.1	462.5	0.315	480.8	0.327	-18.4	-0.012

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-9. Rate impact costs were taken from Table 4-13. Net benefit is the difference between the avoided cost benefit and the rate impact cost.

Table 4-17. Ratepayer Impact - Level 12 Standards, Cooling End-Uses Only
Texas Utilities Electric Company

TUEC Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Rate Impact Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	113.0	19.8	41.0	0.363	28.0	0.248	12.9	0.115
1988	105.6	38.4	37.8	0.358	29.6	0.280	8.2	0.078
1989	104.7	56.8	37.2	0.355	32.3	0.308	4.9	0.047
1990	105.5	75.3	35.6	0.338	35.4	0.336	0.2	0.002
1991	105.4	93.8	34.0	0.322	38.3	0.363	-4.4	-0.041
1992	103.1	111.9	31.6	0.307	40.6	0.394	-9.0	-0.087
1993	101.6	129.8	29.8	0.293	43.3	0.426	-13.6	-0.134
1994	101.6	147.6	28.4	0.279	46.9	0.462	-18.6	-0.183
1995	99.6	165.1	26.5	0.266	49.9	0.501	-23.4	-0.235
1996	91.3	181.1	23.2	0.254	49.6	0.543	-26.4	-0.289
Total	1031.4	181.1	325.0	0.315	394.0	0.382	-69.0	-0.067

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-10. Rate impact costs were taken from Table 4-14. Net benefit is the difference between the avoided cost benefit and the rate impact cost.

Table 4-15a. Ratepayer Impact - Level 8 Appliance Standards, All End-Uses
Texas Utilities Electric Company

Energy-Related Capital Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Rate Impact Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	96.1	27.3	36.6	0.381	15.6	0.162	21.1	0.219
1988	88.4	52.5	33.5	0.378	17.2	0.195	16.2	0.183
1989	86.2	76.9	32.4	0.376	19.2	0.223	13.2	0.153
1990	84.6	100.5	30.2	0.357	21.2	0.251	9.0	0.106
1991	83.3	123.2	28.2	0.338	23.3	0.279	4.9	0.059
1992	81.3	144.7	26.0	0.319	25.3	0.311	0.7	0.008
1993	79.4	165.2	24.0	0.303	27.5	0.346	-3.4	-0.043
1994	78.7	185.2	22.6	0.287	30.2	0.384	-7.6	-0.097
1995	76.0	204.3	20.7	0.273	32.5	0.427	-11.7	-0.154
1996	72.3	222.1	18.7	0.259	34.3	0.474	-15.6	-0.215
Total	826.3	222.1	272.9	0.330	246.2	0.298	26.7	0.032

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-8a. Rate impact costs were taken from Table 4-12. Net benefit is the difference between the avoided cost benefit and the rate impact cost.

Table 4-16a. Ratepayer Impact - Level 12 Cooling End-Uses, Level 8 All Others
Texas Utilities Electric Company

Energy-Related Capital Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Rate Impact Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	160.9	55.2	64.7	0.402	34.3	0.213	30.3	0.188
1988	149.8	106.9	60.1	0.401	36.1	0.241	24.0	0.160
1989	148.2	157.3	59.2	0.400	39.3	0.265	19.9	0.134
1990	147.9	206.9	56.1	0.379	42.7	0.289	13.4	0.091
1991	148.2	255.1	53.2	0.359	46.3	0.312	6.9	0.046
1992	146.3	301.0	49.5	0.338	49.4	0.337	0.1	0.001
1993	145.3	344.4	46.2	0.318	53.0	0.365	-6.7	-0.046
1994	145.4	386.8	43.8	0.301	57.3	0.394	-13.4	-0.092
1995	142.8	427.7	40.8	0.286	60.7	0.425	-19.9	-0.140
1996	134.6	465.8	36.6	0.272	61.8	0.459	-25.2	-0.187
Total	1469.4	465.8	510.2	0.347	480.8	0.327	29.4	0.020

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-9a. Rate impact costs were taken from Table 4-13. Net benefit is the difference between the avoided cost benefit and the rate impact cost.

Table 4-17a. Ratepayer Impact - Level 12 Standards, Cooling End-Uses Only
Texas Utilities Electric Company

Energy-Related Capital Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Rate Impact Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	113.0	48.9	49.0	0.434	28.0	0.248	21.0	0.186
1988	105.6	94.8	46.0	0.436	29.6	0.280	16.4	0.155
1989	104.7	139.6	45.6	0.436	32.3	0.308	13.3	0.127
1990	105.5	183.6	43.4	0.412	35.4	0.336	8.0	0.076
1991	105.4	226.5	41.1	0.390	38.3	0.363	2.8	0.026
1992	103.1	267.1	37.9	0.367	40.6	0.394	-2.7	-0.026
1993	101.6	305.6	35.2	0.346	43.3	0.426	-8.1	-0.080
1994	101.6	343.1	33.3	0.328	46.9	0.462	-13.7	-0.134
1995	99.6	379.6	31.0	0.312	49.9	0.501	-18.9	-0.189
1996	91.3	413.3	27.3	0.298	49.6	0.543	-22.3	-0.245
Total	1031.4	413.3	389.8	0.378	394.0	0.382	-4.2	-0.004

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-10a. Rate impact costs were taken from Table 4-14. Net benefit is the difference between the avoided cost benefit and the rate impact cost.

4.4 SOCIETAL IMPACTS

The cost to society of more efficient appliances is measured by the incremental equipment cost of the more efficient appliances. The benefits remain the avoided production costs. Before describing these results, we define our calculation of equipment costs.

The relatively higher cost of efficient appliances has two impacts on the market for appliances. First, those who purchase new appliances pay a higher price. Second, total purchases of appliances may change, because either higher equipment costs discourage purchasers or lower operating costs encourage them. To account for the benefits properly, we multiplied the per unit incremental equipment costs by the units purchased in the base case. The alternative, taking the difference between gross equipment expenditures in the policy and base cases (including changes in the number of units purchased) misrepresents the benefits. For example, if higher equipment costs cause a decrease in purchases of an appliance, then gross equipment costs in the policy case would be lower, which would appear as a benefit. Conversely, if lower operating costs induce more purchases, the higher gross equipment expenditures would be calculated as a cost. For these reasons, cbanges in per unit costs are applied to the level of purchases in the base case (DOE, 1983).

Tables 4-18,19,20 summarize the societal impact for each policy case using the TUEC avoided cost methodology. Tables 4-18a,19a,20a summarize the societal impacts using the energy related capital avoided cost methodology. The format of the tables is similar to those used to summarize the ratepayer impact calculations. After presenting the load impacts and avoided production cost previously described, the equipment cost for the standard is listed. The difference between the avoided production cost benefit and the equipment cost is the net benefit to society. All dollar amounts (except equipment cost) are the 1985 present value of saving the increment of energy for 12 years. We continue to use the TUEC rate of disadvantage, 11.5%, to express our results in 1985 present value dollars.

From a societal perspective, only the level 8 standard is cost-effective. The remaining two standards result in significant net losses for either choice of avoided cost methodology. There is reason to believe that the cost premium associated with the more efficient appliances may be over-estimated (see Kahn, 1986a). Nevertheless, it is unlikely that revised estimation of these costs would alter the general trend of our results.

Table 4-18. Societal Impact - Level 8 Appliance Standards, All End-Uses
Texas Utilities Electric Company

TUEC Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Equipment Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	96.1	16.9	34.8	0.363	23.8	0.247	11.0	0.116
1988	88.4	32.4	31.7	0.358	23.1	0.261	8.6	0.097
1989	86.2	47.5	30.6	0.355	22.5	0.261	8.1	0.094
1990	84.6	62.4	28.6	0.338	21.6	0.256	7.0	0.082
1991	83.3	77.0	26.8	0.322	20.5	0.246	6.3	0.076
1992	81.3	91.3	24.9	0.307	19.1	0.235	5.8	0.072
1993	79.4	105.3	23.3	0.293	17.8	0.224	5.5	0.069
1994	78.7	119.1	22.0	0.279	16.6	0.211	5.4	0.068
1995	76.0	132.4	20.2	0.266	15.7	0.206	4.5	0.060
1996	72.3	145.1	18.3	0.254	14.9	0.206	3.4	0.048
Total	826.3	145.1	261.2	0.316	195.5	0.237	65.7	0.079

All dollar amounts (except equipment cost) are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-8. Equipment costs were calculated by the LBL Residential Energy Demand Model. Net benefit is the difference between the avoided cost benefit and the equipment cost.

Table 4-19. Societal Impact - Level 12 Cooling End-Uses, Level 8 All Others
Texas Utilities Electric Company

TUEC Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Equipment Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	160.9	28.3	58.3	0.363	76.0	0.472	(17.7)	(0.109)
1988	149.8	54.6	53.6	0.358	75.4	0.503	(21.8)	(0.145)
1989	148.2	80.6	52.6	0.355	75.1	0.507	(22.5)	(0.152)
1990	147.9	106.6	50.0	0.338	73.6	0.498	(23.6)	(0.160)
1991	148.2	132.6	47.8	0.322	70.8	0.478	(23.0)	(0.166)
1992	146.3	158.3	44.9	0.307	67.0	0.458	(22.1)	(0.151)
1993	145.3	183.8	42.6	0.293	62.9	0.433	(20.3)	(0.140)
1994	145.4	209.3	40.6	0.279	59.5	0.410	(18.9)	(0.131)
1995	142.8	234.4	38.0	0.266	57.1	0.400	(19.1)	(0.134)
1996	134.6	258.1	34.2	0.254	55.0	0.409	(20.8)	(0.155)
Total	1469.4	258.1	462.5	0.315	672.4	0.458	(209.9)	(0.143)

All dollar amounts (except equipment cost) are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-9. Equipment costs were calculated by the LBL Residential Energy Demand Model. Net benefit is the difference between the avoided cost benefit and the equipment cost.

Table 4-20. Societal Impact - Level 12 Standards, Cooling End-Uses Only
Texas Utilities Electric Company

TUEC Avoided Cost Methodology

Year	Load Shape Change Energy (GWh)	Load Shape Change Capacity (MW)	A Avoided Cost Benefit Total (M$)	A Avoided Cost Benefit ($/kWh)	B Equipment Cost Total (M$)	B Equipment Cost ($/kWh)	A - B Net Benefit Total (M$)	A - B Net Benefit ($/kWh)
1987	113.0	19.8	41.0	0.363	67.5	0.597	(26.5)	(0.234)
1988	105.6	38.4	37.8	0.358	67.4	0.639	(29.6)	(0.281)
1989	104.7	56.8	37.2	0.355	67.6	0.645	(30.4)	(0.290)
1990	105.5	75.3	35.6	0.338	66.5	0.630	(30.9)	(0.292)
1991	105.4	93.8	34.0	0.322	64.0	0.607	(30.0)	(0.285)
1992	103.1	111.9	31.6	0.307	60.5	0.587	(28.9)	(0.280)
1993	101.6	129.8	29.8	0.293	56.7	0.558	(26.9)	(0.265)
1994	101.6	147.6	28.4	0.279	53.6	0.528	(25.2)	(0.249)
1995	99.6	165.1	26.5	0.266	51.4	0.516	(24.9)	(0.250)
1996	91.3	181.1	23.2	0.254	49.5	0.542	(26.3)	(0.288)
Total	1031.4	181.1	325.0	0.315	604.7	0.586	(279.7)	(0.271)

All dollar amounts (except equipment cost) are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-10. Equipment costs were calculated by the LBL Residential Energy Demand Model. Net benefit is the difference between the avoided cost benefit and the equipment cost.

Table 4-18a. Societal Impact - Level 8 Appliance Standards, All End-Uses
Texas Utilities Electric Company

Energy-Related Capital Avoided Cost Methodology

Year	Load Shape Change Energy (GWh)	Load Shape Change Capacity (MW)	A Avoided Cost Benefit Total (M$)	A Avoided Cost Benefit ($/kWh)	B Equipment Cost Total (M$)	B Equipment Cost ($/kWh)	A - B Net Benefit Total (M$)	A - B Net Benefit ($/kWh)
1987	96.1	27.3	36.6	0.381	23.8	0.247	12.8	0.134
1988	88.4	52.5	33.5	0.378	23.1	0.261	10.4	0.117
1989	86.2	76.9	32.4	0.376	22.5	0.261	9.9	0.115
1990	84.6	100.5	30.2	0.357	21.6	0.256	8.6	0.101
1991	83.3	123.2	28.2	0.338	20.5	0.246	7.7	0.092
1992	81.3	144.7	26.0	0.319	19.1	0.235	6.9	0.084
1993	79.4	165.2	24.0	0.303	17.8	0.224	6.2	0.079
1994	78.7	185.2	22.6	0.287	16.6	0.211	6.0	0.076
1995	76.0	204.3	20.7	0.273	15.7	0.206	5.0	0.067
1996	72.3	222.1	18.7	0.259	14.9	0.206	3.8	0.053
Total	826.3	222.1	272.9	0.330	195.5	0.237	77.4	0.093

All dollar amounts (except equipment cost) are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-8a. Equipment costs were calculated by the LBL Residential Energy Demand Model. Net benefit is the difference between the avoided cost benefit and the equipment cost.

Table 4-19a. Societal Impact - Level 12 Cooling End-Uses, Level 8 All Others
Texas Utilities Electric Company

Energy-Related Capital Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Equipment Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	160.9	55.2	64.7	0.402	76.0	0.472	(11.3)	(0.070)
1988	149.8	106.9	60.1	0.401	75.4	0.503	(15.3)	(0.102)
1989	148.2	157.3	59.2	0.400	75.1	0.507	(15.9)	(0.107)
1990	147.9	206.9	56.1	0.379	73.6	0.498	(17.5)	(0.119)
1991	148.2	255.1	53.2	0.359	70.8	0.478	(17.6)	(0.119)
1992	146.3	301.0	49.5	0.338	67.0	0.458	(17.5)	(0.120)
1993	145.3	344.4	46.2	0.318	62.9	0.433	(16.7)	(0.115)
1994	145.4	386.8	43.8	0.301	59.5	0.410	(15.7)	(0.109)
1995	142.8	427.7	40.8	0.286	57.1	0.400	(16.3)	(0.114)
1996	134.6	465.8	36.6	0.272	55.0	0.409	(18.4)	(0.137)
Total	1469.4	465.8	510.2	0.347	672.4	0.458	(162.2)	(0.111)

All dollar amounts (except equipment cost) are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-9a. Equipment costs were calculated by the LBL Residential Energy Demand Model. Net benefit is the difference between the avoided cost benefit and the equipment cost.

Table 4-20a. Societal Impact - Level 12 Standards, Cooling End-Uses Only
Texas Utilities Electric Company

Energy-Related Capital Avoided Cost Methodology

	Load Shape Change		A Avoided Cost Benefit		B Equipment Cost		A - B Net Benefit	
Year	Energy (GWh)	Capacity (MW)	Total (M$)	($/kWh)	Total (M$)	($/kWh)	Total (M$)	($/kWh)
1987	113.0	48.9	49.0	0.434	67.5	0.597	(18.5)	(0.163)
1988	105.6	94.8	46.0	0.436	67.4	0.639	(21.4)	(0.203)
1989	104.7	139.6	45.6	0.436	67.6	0.645	(22.0)	(0.209)
1990	105.5	183.6	43.4	0.412	66.5	0.630	(23.1)	(0.218)
1991	105.4	226.5	41.1	0.390	64.0	0.607	(22.9)	(0.217)
1992	103.1	267.1	37.9	0.367	60.5	0.587	(22.6)	(0.220)
1993	101.6	305.6	35.2	0.346	56.7	0.558	(21.5)	(0.212)
1994	101.6	343.1	33.3	0.328	53.6	0.528	(20.3)	(0.200)
1995	99.6	379.6	31.0	0.312	51.4	0.516	(20.4)	(0.204)
1996	91.3	413.3	27.3	0.298	49.5	0.542	(22.2)	(0.244)
Total	1031.4	413.3	389.8	0.378	604.7	0.586	(214.9)	(0.208)

All dollar amounts (except equipment cost) are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the TUEC rate of disadvantage (11.5%). Avoided cost benefits were taken from Table 4-10a. Equipment costs were calculated by the LBL Residential Energy Demand Model. Net benefit is the difference between the avoided cost benefit and the equipment cost.

5. CONCLUSION

We have performed an integrated analysis of the financial impacts of mandatory residential appliance efficiency standards in the Texas Power & Light service territory of the Texas Utilities Electric Company. Load shape impacts were calculated using the LBL Residential Energy and LBL Residential Hourly and Peak Demand Models. Financial impacts were based on published filings by TUEC for the purchase of power from small power producers and cogenerators. Financial impacts on both ratepayers and society were calculated.

The analysis began with detailed forecasts of energy and hourly demands from the LBL Residential Energy and LBL Residential Hourly and Peak Demand Models. Together, these models are capable of producing a twenty year forecast of hourly end-use electricity demands. Though not analyzed in the current study, the LBL Residential Energy Model also accounts for non-electrical energy use and fuel-switching. Calibration to historic sales and peak demands preceded these forecasts and achieved good agreement with available utility data.

Three levels of mandatory residential appliance efficiency standards with a start date of 1987 were chosen to span a range of load shape impacts. The first, Level 8, mandated modest increases in the efficiency of all appliances. This standard produced a relatively even decrease in forecast loads throughout the year. The second, Level 8/12, was essentially the same standard but with a very high minimum efficiency for central air conditioners. This standard produced dramatic reductions in summer peak demands and, due to the high saturation of central air conditioners, large energy savings as well. The third standard, Level 12/AC, targeted only space cooling end-uses. This standard produced large reductions in peak demands along with modest decreases in energy use. The load shape impacts of the three standards are summarized in Table 5-1.

Table 5-1. Summary of Load Shape Impacts

Case	Growth (1987-1996) Energy (%/yr)	Growth (1987-1996) Demand (%/yr)	Load Factor (%)	Impact by 1996 Energy (GWh)	Impact by 1996 Demand (MW)	Impact by 1996 Demand (MW*)
Base	3.48	3.07	43			
Level 8	2.84	2.28	44	826.3	269.2	221.1
Level 8/12	2.30	1.30	45	1469.4	566.4	465.8
Level 12/AC	2.67	1.52	46	1031.4	501.7	413.3

* Average change in demand for 500 highest residential class loads.

The financial impact calculations relied largely on the results of TUEC avoided cost filings for cogenerators and small power producers to determine both long- and short-run avoided production cost benefits for the load shape impacts. In the short-run, avoided production costs are determined by the variable operating cost of existing plants. In the long-run, capital costs of as yet un-built plants figure into the calculation of avoided production costs.

Two avoided cost methodologies were evaluated. The first was based on a literal interpretation of TUEC's avoided cost filing. The second isolated a reliability or capacity-related component and an energy-related component of the long-run capital investment decision.

The ratepayer impact of load shape changes was measured by comparing the avoided production cost benefits against the rate impact costs. The rate impact cost is the under-recovery of fixed costs resulting from decreased sales of electricity, which must be recovered from existing customers. The rate impact cost was calculated by subtracting lost revenues, as determined by the TUEC forecast of future retail rates, from avoided marginal variable operating costs. The calculation of the societal impact of load shape changes considered avoided production costs and the additional cost of the more efficient appliances.

Our major conclusion is that only the level 8 standard is cost-effective from the both perspectives. This result holds for both avoided cost methodologies. For the other standards, the rate impact cost for the ratepayer perspective or the added cost of appliance efficiency for the societal perspective exceeds all avoided production cost benefits. For the ratepayer perspective, we observed that the cost-effectiveness of residential appliance efficiency standards hinges ultimately on an issue of timing. While cost-effective to ratepayers in the short-run, the rate impact cost of increased appliance efficiencies eventually exceeds the avoided production cost benefits. We noted uncertainty in our calculation of the increased cost of appliance efficiency, but it is unlikely that revised costs would change the basic conclusions. Tables 5-2 and 5-2a summarize the financial impacts of the three policy cases for each avoided cost methodology.

Table 5-2. Summary of Financial Impacts
TUEC Avoided Cost Methodology

Ratepayer Perspective:

Standard	A Avoided Cost (M 1985$)	B Rate Impact (M 1985$)	A-B Net Impact (M 1985$)	 (1985$/kWh)
Level 8	261	246	15	0.018
Level 8/12	462	481	(18)	(0.012)
Level 12/AC	325	394	(69)	(0.067)

Societal Perspective:

Standard	A Avoided Cost (M 1985$)	B Equipment (M 1985$)	A-B Net Impact (M 1985$)	 (1985$/kWh)
Level 8	261	196	65	0.079
Level 8/12	463	672	(210)	(0.143)
Level 12/AC	325	605	(280)	(0.271)

The per unit values, 1985$/kWh, represent the present value of the impact over the lifetime of the appliances (12 years).

Table 5-2a. Summary of Financial Impacts
Energy-Related Capital Avoided Cost Methodology

Ratepayer Perspective:

Standard	A Avoided Cost (M 1985$)	B Rate Impact (M 1985$)	A-B Net Impact (M 1985$)	 (1985$/kWh)
Level 8	273	246	27	0.032
Level 8/12	510	481	29	0.020
Level 12/AC	390	394	(4)	(0.004)

Societal Perspective:

Standard	A Avoided Cost (M 1985$)	B Equipment (M 1985$)	A-B Net Impact (M 1985$)	 (1985$/kWh)
Level 8	273	196	77	0.093
Level 8/12	510	672	(162)	(0.111)
Level 12/AC	390	605	(215)	(0.208)

The per unit values, 1985$/kWh, represent the present value of the impact over the lifetime of the appliances (12 years).

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