LBL-21597

# Lawrence Berkeley Laboratory

UNIVERSITY OF CALIFORNIA

## APPLIED SCIENCE DIVISION

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**The Nevada Power Company**

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

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# FINANCIAL IMPACTS ON UTILITIES OF LOAD SHAPE CHANGES

## The Nevada Power Company

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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 on 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. Avoided costs are calculated independently with a production cost simulation model developed for the Electric Power Research Institute. 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 Nevada Power Company (NPC). It provides the interested reader with the underlying assumptions and modeling procedures used to assess the financial impacts of policies that increase the efficiency of residential appliances. A separate document describes our overall methods and conclusions (Kahn, 1986a).

The NPC case study is the fourth in a series of five utility case studies performed by LBL. In addition to NPC, 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 Texas Utilities Electric Company (Kahn, 1984; Pignone, 1984; Eto, 1984a; Eto, 1984b, Eto 1986).

We remind the reader that the present study is of a simplified and stylized characterization of the Nevada Power Company. Even a simplified characterization of an electric utility, however, requires substantial data to run the models and to calculate financial impacts. We were fortunate in choosing NPC as a case study because of the ready availability of the necessary demand, load, and supply data in an easily accessed format. NPC 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 benchmarking process for the production cost model used to develop an independent forecast of avoided costs. The final section summarizes the results of our case study.

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[1] We are especially grateful for the efforts of Mr. Larry Tamashiro, Mr. Frank Londen, Ms. Cindy Gilliam, Mr. Ron Zanoni, and Ms. Deanne Nelson.

# 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 NEVADA POWER COMPANY

The subject of our case study is the residential class of the Nevada Power Company (NPC). NPC is located in the southwestern part of the US. The service territory is roughly defined by the boundaries of Clark county, Nevada (see Figure 2-1).

NPC is a relatively small electric utility. Total sales in 1984 were 6572 GWh and peak demand was 1502 MW. By contrast, the corresponding figures for the subject of our companion case study, Texas Utilities Electric Company (TUEC), are roughly ten times larger. The NPC residential class, however, comprised 44% of NPC sales, while that of TUEC represented 33% of total sales.

NPC anticipates continued strong demand growth into the 1990's. According to the Base Case in the 1984 Resource Plan, energy is expected to increase at 3.7%/year through 1999, and peak demands are expected to grow at 3.8%/year over the same period (NPC, 1984). Together, these predictions suggest that growth will come at the expense of further declines in an already low load factor of 49.9% in 1984. The driving forces are expected to come from the residential and commercial classes. Given the large fraction of sales accounted for by the residential class, we expect that the load shape impacts of appliance efficiency policies will have direct consequences on future system load factors.

NPC costs are relatively low compared to national averages. In 1985, residential electric rates for 1000 kWh/mo were 0.058 \$/kWh as compared to the national average for 1985 of 0.076 \$/kWh (DOE, 1985). The utility is also in the process of phasing lower cost coal plants into the generation mix. Between 1985 and 1999, Nevada Power expects coal-fired generation to reduce oil and gas generation from 14% to 6%. We expect that these relatively lower costs will have important consequences for our financial analyses of load shape modifications.

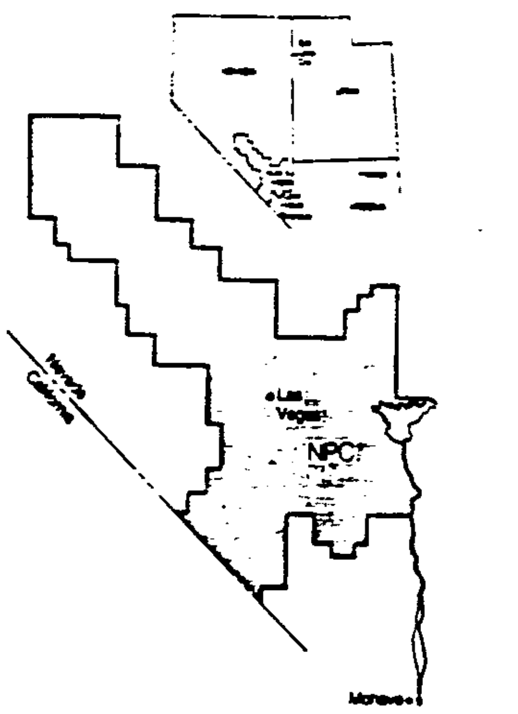


Figure 2-1 Nevada Power Company service territory.

## 2.2 RESIDENTIAL APPLIANCE EFFICIENCY STANDARDS

In this case study, we examine the financial impacts of three appliance efficiency standards starting in 1987. Table 2-1 compares the efficiencies mandated by each standard to existing appliance efficiencies. Existing efficiencies for 1985 are described by both a stock-average or existing efficiency and a marginal or new appliance efficiency. These efficiencies are estimates based on a forecast of the LBL Residential Energy Model. These estimates were derived by using NPC estimates for appliance unit energy consumption in 1980 and 1984 (depending on the appliance—see section 3), historical and projected fuel prices, and historical and projected per capita personal income. They represent our best estimate in the absence of measured data. The high efficiency of new gas ranges is the result of replacing pilot lights by electronic or sparking ignition devices. Because in this case the new appliance efficiency is so high, the standard has no effect on the energy consumption of these appliances.

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. These standards are imposed as minimum efficiency requirements for new equipment.

Table 2-1. Appliance Efficiency Comparison

| Appliance | 1985 Existing | 1985 New | Level 8 | Level 8/12 | Level 12/AC |
|---|---|---|---|---|---|
| Space Heating (AFUE%) | | | | | |
| gas | 64.36 | 71.45 | 85.72 | 85.72 | – |
| oil | 75.08 | 78.77 | 90.98 | 90.98 | – |
| Air Conditioning | | | | | |
| room (EER) | 6.58 | 7.15 | 8.87 | 8.87 | 8.87 |
| central (SEER) | 7.08 | 7.26 | 8.42 | 12.00 | 12.00 |
| Water Heating (%) | | | | | |
| electric | 81.01 | 82.86 | 93.60 | 93.60 | – |
| gas | 53.03 | 62.61 | 81.75 | 81.75 | – |
| Refrigerators ($ft^3$/kWh/d) | 4.96 | 6.64 | 11.28 | 11.28 | – |
| Freezers ($ft^3$/kWh/d) | 9.86 | 12.24 | 22.34 | 22.34 | – |
| Ranges (%) | | | | | |
| electric | 39.40 | 44.27 | 47.51 | 47.51 | – |
| gas | 17.57 | 31.57 | 20.27 | 20.27 | – |
| Dryer (dry lbs/kWh) | | | | | |
| electric | 2.71 | 2.90 | 2.96 | 2.96 | – |
| gas (@3412 Btu/kWh) | 2.28 | 2.65 | 2.61 | 2.61 | – |

Source: Forecast of the LBL Residential Energy Model, using NPC data as inputs.

# 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 (LBLREM), 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 the annual data 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.

LBLREM 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 end-use electricity sales forecast by LBLREM into seasonal and hourly loads. Space-conditioning end-use loads are dependent upon weather as well as time of day. The inputs to the model, in addition to the forecasts from the LBL Residential Energy Model, are hourly weather data and seasonal hourly load profiles by end-use.

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 load shape impacts of the appliance standards are measured by the differences 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 Nevada Power Company. Specifically, the LBL Model requires data on:

- appliance and heating equipment saturations and changes in these saturations over time;
- saturations of appliances in new homes (marginal saturations or penetrations);
- annual energy use of each appliance in the base 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 consumption for ten end-uses and three housing types for up to 25 years.

Our primary source of data was that used by the utility in developing its own forecasts. We were fortunate that NPC had recently acquired software from the Electric Power Research Institute to develop its own end-use energy forecasts. The 1984 NPC Residential Survey Frequency Report (NPC, 1985) and data contained in the documentation for the 1984 NPC Resource Plan: 1984-2005 (NPC, 1984) provided the bulk of this information. Supplementary data were gathered through personal communications from the utility.

### 3.1.1 Appliance Saturations and Marginal Saturations

Absolute and marginal appliance saturations are summarized in Table 3-1. We took the appliance saturations for 1980 from the NPC documents and chose marginal saturations so that the LBL forecast of absolute saturations for 1984 matched the NPC values for 1984.

For water heaters, dryers and ranges, the NPC Residential Frequency Survey indicated that a small percentage of people either did not know what fuel their appliance used, or owned appliances that used other fuels (such as LP gas). For water heaters, these responses account for less than four percent of the total; for dryers and ranges, less than one percent responded that they did not know. We assigned these appliances to fuels in the same proportions as other respondents, and consequently ignored the few appliances that may use other fuels.

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

| End-Use | Appliance | 1980 | 1984 | Marginals |
|---|---|---|---|---|
| Heating | Electric Furnace | 0.340 | 0.380 | 0.500 |
| | Gas Furnace | 0.380 | 0.360 | 0.320 |
| | Oil Furnace | 0.011 | 0.010 | 0.009 |
| | Heat Pump | 0.110 | 0.100 | 0.077 |
| | Electric Non-cent | 0.079 | 0.079 | 0.006 |
| | Gas Non-cent | 0.079 | 0.071 | 0.004 |
| Cooling | Elect Cent A/C (excluding heat pumps) | 0.770 | 0.750 | 0.590 |
| | One or more window A/C | 0.052 | 0.048 | 0.020 |
| | None | 0.071 | 0.098 | 0.290 |
| Water Heat | Electric | 0.490 | 0.450 | 0.160 |
| | Gas | 0.510 | 0.550 | 0.830 |
| Cooking | Electric | 0.600 | 0.610 | 0.620 |
| | Gas | 0.400 | 0.390 | 0.390 |
| Clothes Drying | Electric | 0.530 | 0.500 | 0.220 |
| | Gas | 0.200 | 0.200 | 0.200 |
| Food Storage | Refrigerator (avg # per household) | 1.170 | 1.180 | 1.200 |
| | Freezer | 0.250 | 0.320 | 0.600 |
| Lighting | Lighting | 1.000 | 1.000 | 1.000 |

Sources: NPC, 1984;
NPC, 1985a.

### 3.1.2 Appliance Energy Consumption

The primary source of estimates for unit energy consumption (UEC) by appliance was 1980 data used by NPC in its forecasting models. An exception is the UEC for gas dryers, which was obtained from the LBL library of default values (DOE, 1983). Later, we received UEC's for electric appliances from a conditional demand analysis performed on 1984 data for NPC. Our analysis used the conditional demand UEC's where possible, but for natural gas and oil appliances we had to rely on the original estimates. Table 3-2 reports on the final values used in our forecasts. In reviewing Table 3-1, note that UEC's are expressed in million Btu of resource energy and for electricity we adopt the convention of using 11,500 Btu/kWh as a conversion factor.

Since the conditional demand UECs were measured in 1984 and not in 1980, we inserted these values into the model in 1984, and "backcast" the energy use of these appliances in 1980.

For the temperature-sensitive UEC's, the 1984 values were first adjusted to be representative of energy use in an average weather year. Table 3-2 includes only those energy consumption numbers that we obtained directly from NPC documents, and not those backcasted to the base year. The conditional demand UECs were also broken down by house type (single family, multifamily, mobile home); we calculated a weighted average UEC from these numbers.

Air conditioning UECs have been adjusted to account for the significant number of evaporative coolers installed in conjunction with air conditioners. The conditional demand study indicated that the energy consumption of air conditioners with evaporative coolers was substantially lower than that for air conditioners alone. We used the saturation data for evaporative coolers and air conditioners and the conditional demand UECs to create a weighted-average UEC for cooling appliances.

Heat pump heating UECs have been adjusted to account for a disparity in the results from the conditional demand analysis. The NPC analysis suggested that heat pump UECs were greater than the corresponding UEC for electric resistance heat. This disparity was apparently caused by the fact that heat pumps are in general found in larger, newer homes with wealthy occupants, while electric resistance heat is found in smaller, older homes with less wealthy occupants. We decided to estimate a heat pump UEC by using the ratio of heat pump heating UEC to central electric resistance heat UEC in the outputs from NPC's REEPS output, and applying this ratio to the central electric heating UEC from the conditional demand analysis. This procedure was necessary to preserve our analytical assumption of an "average" house.

Table 3-2. Appliance Unit Energy Consumption (MMBtu of Resource Energy)

| Appliance | 1980 UEC | 1984 UEC |
|---|---|---|
| Electric Furnace | | 35.80 |
| Gas Furnace | 93.05 | |
| Oil Furnace | 94.39 | |
| Heat pump (heating) | | 25.94 |
| Electric Non-central | | 24.21 |
| Gas Non-central | 101.50 | |
| Central A/C | | 34.66 |
| One or more Window A/C(per unit) | | 26.20 |
| Heat Pump (cooling) | | 34.66 |
| Electric Water Heat | | 33.03 |
| Gas Water Heat | 45.14 | |
| Electric Range | | 6.79 |
| Gas Range | 15.12 | |
| Electric Dryer | | 9.09 |
| Gas Dryer | 6.88 | |
| Refrigerator | | 18.64 |
| Freezer | | 12.01 |
| Lighting | 23.94 | |

Sources: NPC, 1984;
personal communication from NPC, November 5, 1985;
DOE, 1983.

### 3.1.3 Number of Households

Our analysis used an NPC forecast of the number of housing units as a proxy for the number of households. The number of households is the number of housing units times the occupancy rate (93%). The projection was extrapolated to the year 2005 by using the weighted average growth rate for all housing units for the years 1999 to 2000 (2.76%/yr.). The total number of housing units existing at the beginning of the given year and the net increase per year are shown in Table 3-3.

Table 3-3. Number of Housing Units 1980-2005

| Year | Total | Net Increase |
|---|---|---|
| 1980 | 176666 | 8300 |
| 1981 | 184966 | 6621 |
| 1982 | 191587 | 6909 |
| 1983 | 198496 | 7822 |
| 1984 | 206318 | 8163 |
| 1985 | 214481 | 8796 |
| 1986 | 223277 | 9190 |
| 1987 | 232467 | 9415 |
| 1988 | 241883 | 9820 |
| 1989 | 251702 | 10262 |
| 1990 | 261965 | 10702 |
| 1991 | 272667 | 7371 |
| 1992 | 280038 | 7579 |
| 1993 | 287617 | 7804 |
| 1994 | 295421 | 8025 |
| 1995 | 303446 | 8549 |
| 1996 | 311995 | 8798 |
| 1997 | 320793 | 9371 |
| 1998 | 330164 | 9653 |
| 1999 | 339817 | 9379 |
| 2000 | 349196 | 9638 |
| 2001 | 358834 | 9904 |
| 2002 | 368738 | 10177 |
| 2003 | 378915 | 10458 |
| 2004 | 389373 | 10747 |
| 2005 | 400120 | — |

Source: personal communication from NPC, April 11, 1985.

### 3.1.4 Historic Numbers of Customers

The average number of residential customers on the NPC system for the years 1980-1984 are shown in Table 3-4. The number of customers is smaller than the number of housing units because the occupancy rate in the Las Vegas area in 1984 was 93%.

Table 3-4. Historical Number of Residential Customers

| Year | Avg # of Customers |
|---|---|
| 1980 | 164.856 |
| 1981 | 174,553 |
| 1982 | 180.575 |
| 1983 | 185,874 |
| 1984 | 194.498 |

Source: personal communication from NPC, March 25, 1985.

### 3.1.5 Housing Type

Table 3-5 shows the breakdown of housing by type in 1984. Due to data limitations, we modeled only one house type, the average customer.

Table 3-5. Housing Type (1984)

| Housing Type | Percent |
|---|---|
| Single family detached | 51% |
| Multifamily <= 4 units | 13% |
| Multifamily > 5 units | 28% |
| Mobile Home | 8% |

Source: personal communication from NPC, March 25, 1985.

### 3.1.8 Income per Household

From LBL's SEEDIS database of U.S. census data (LBL, 1982), we found that the average household income in Clark County, NV was $14,253 in 1975 dollars (the LBL Model is calibrated in 1975 dollars). For the projection, we used the utility's percentage growth rates for growth in personal income per capita from the NPC Resource Plan: 1984-2005. We used the NPC base-case values for the period 1980 to 1985, and Bureau of Economic Analysis (BEA) estimates reported in the NPC Resource Plan for the period 1986 to 2000. The BEA estimates are roughly one percentage point lower than those actually used by NPC in its base case.

The growth rate of household income may be different than that of per capita income, but these two rates of growth will be close as long as the number of people per household is not changing drastically. The growth rates assumed for the projection are shown in Table 3-6. These growth rates result in the forecast of per capita personal income shown in Table 3-7 (1975 dollars/capita).

Table 3-6. Projected Growth Rates in Per Capita Personal Income

| Years | Growth Rate (% per year) |
|---|---|
| 1980-83 | 0.92% |
| 1983-85 | 1.32% |
| 1986-90 | 2.05% |
| 1991-2005 | 1.68% |

Source: NPC, 1984.

Table 3-7. Projected Personal Income

| Year | Income (1975$/capita) |
|---|---|
| 1980 | 14,253 |
| 1981 | 14,384 |
| 1982 | 14,516 |
| 1983 | 14,708 |
| 1984 | 14,902 |
| 1985 | 15,099 |
| 1990 | 15,908 |
| 1995 | 16,457 |
| 2000 | 17,024 |
| 2005 | 17,611 |

Source: NPC, 1984;
LBL, 1982.

### 3.1.7 Residential Natural Gas Prices

Table 3-8 shows historical and projected prices for natural gas in the NPC service territory (in 1975 dollars per million Btu of resource energy). For 1984 to 1990, the price is projected to grow at a 1.1% real rate of growth each year; for 1990 to 2000, the real growth rate is projected to be 3.0% annually; from 2000 to 2010, NPC projects 0.7% annual real price increases.

### 3.1.8 Distillate Fuel Oil Prices

Fuel oil prices were not a critical input to our projection because only a small percentage of NPC customers own oil-fired equipment. The prices for the years 1980 to 1984 were obtained by interpolating between data for Idaho and Oregon given in the Monthly Energy Review (DOE, 1984). This publication only presents fuel oil price data for selected states.

After averaging as stated above, the distillate fuel oil prices were escalated at 0.8% annually for the years 1984-1990, at 3.1% annually for 1990-2000, and 0.95% annually for 2000-2005. These projected growth rates were obtained by averaging NPC projected real growth rates for No.6 residual fuel oil and No. 2 diesel oil. Table 3-8 shows the results of the averaging.

### 3.1.9 Residential Electricity Prices

Historical and projected prices to the residential sector are shown in Table 3-8 (in 1975 dollars per million Btu of resource energy, calculated by convention at 11,500 Btu per kWh). NPC expects that electricity prices will remain constant in real terms from 1984 to 1990. After 1990, NPC forecasts that prices will escalate at 1.2 percent per year in real terms.

Table 3-8. Residential Energy Prices

| Year | Natural Gas (1975$/MMBtu) | Dist. Fuel Oil (1975$/MMBtu) | Electricity (1975$/MMBtu) |
|---|---|---|---|
| 1980 | 1.998 | 4.741 | 2.331 |
| 1981 | 1.880 | 5.059 | 2.087 |
| 1982 | 2.328 | 4.822 | 2.374 |
| 1983 | 2.677 | 4.343 | 2.478 |
| 1984 | 3.217 | 4.091 | 2.373 |
| 1985 | 3.071 | 4.125 | 2.373 |
| 1990 | 3.441 | 4.291 | 2.373 |
| 1995 | 4.161 | 5.000 | 2.520 |
| 2000 | 4.633 | 5.822 | 2.674 |
| 2005 | 4.979 | 6.106 | 2.837 |

Sources: DOE, 1984.
NPC, 1984.
personal communication from NPC, March 25, 1985.

### 3.1.10 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 Las Vegas, Nevada. Both prototypes were developed from data on the thermal characteristics or thermal integrity (TI) of the average new and average existing house in the NPC service from the 1984 NPC Residential Frequency Survey (NPC, 1985). We then calculated the the ratios (called the thermal integrity ratios or TIRs) of annual heating and cooling loads for two houses. For cooling loads, we calculated a TIR of 0.742; for heating, we calculated a TIR of 0.601. Formally,

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

where:

$\text{Load}_{\text{new}}$ = 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 NPC on actual heating and cooling loads for average existing houses to those of new houses.

### 3.1.11 Default values

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

- cost vs. energy use curves for each appliance
- cost vs. energy-use curves for thermal integrity improvements
- Market share elasticities
- Usage elasticities
- Floor area per household
- Number of conservation retrofits
- 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.

After introducing the data available for our use in performing the calibration, we describe the results for three levels of disaggregation: annual sales, monthly sales and peak demands, and hourly load shapes for class peak days.

### 3.2.1 Data for Calibration

The calibration process is limited only by the availability of data on historic consumption. In this respect, we were fortunate to obtain a data tape of 1984 recorded hourly system loads and estimated hourly residential class loads. Time-series data, however, were not available.

To incorporate the 1984 load data into our calibration process, we had to consider several modifications to components of our modeling procedure:

*Weather* for 1984 was used to drive the LBL Hourly and Peak Demand Model, in order to compare model estimates of residential loads with NPC data reported for 1984. For forecasting purposes, average weather was used to drive the peak model. Comparison of reported loads for specific years with model results required weather normalization. The method chosen was to scale space heating by heating degree days (base 65), and cooling by cooling degree days (base 65).

*Miscellaneous* load shape was taken 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 one derived from the differences between the recorded totals and our estimates for the other end-uses. This approach would, of course, reduce the error in the total residential load shape. For now, we are content to report the error without using this technique to minimize it. We simply note that the assumed flat profile for miscellaneous contributes to some error in the total residential load shape.

*Transmission and distribution losses* are included in the reported residential loads from NPC in 1984. Loads from the LBL model exclude these losses. While NPC estimated the losses to be 9.1%, the area under the hourly load curve for the year adds up to 12% more than the reported residential sales. We assumed that the residential sales figure was correct, and scaled our estimate of the residential load down in each hour by a constant factor. The model estimates of load curves were compared with the NPC reported values after the NPC values were normalized to residential sales.

### 3.2.2 Annual Totals

Total annual residential sales forecast by the model were compared to NPC data. No attempt was made at this point to adjust the model results to reflect actual weather; an average weather year is assumed in these model results. Space conditioning represents about 33% of the NPC residential sales (in 1980), so fluctuations of 10% in the weather could produce differences of about 3% our forecasts and estimates based on normal weather or estimates based on actual residential sales. Table 3-9 shows the results. The errors are in an acceptable range (-4 to +1%). Electricity consumption per customer also agrees reasonably well with data.

Table 3-9. LBL Backcast Compared to NPC Residential Sales

| | GWH | | | kwh/customer | | |
|---|---|---|---|---|---|---|
| | LBL | NPC | % error | LBL | NPC | % error |
| 1980 | 2343.33 | 2348.603 | -0.2 | 14215 | 14246 | -0.2 |
| 1981 | 2430.76 | 2535.735 | -4.1 | 14083 | 14527 | -3.1 |
| 1982 | 2472.32 | 2477.559 | -0.2 | 13829 | 13720 | +0.8 |
| 1983 | 2517.24 | 2499.033 | +0.7 | 13591 | 13445 | +1.1 |
| 1984 | 2593.79 | 2686.391 | -3.4 | 13266 | 13812 | -4.0 |

### 3.2.3 Monthly Totals and Peaks

Monthly residential sales for 1984 were compared with model estimates. The winter months showed the least error; summer sales were underestimated; and spring sales were overestimated (Figure 3-1). The mean absolute percentage error in monthly sales was 9.0%. The largest error was 19.2%, which occurred in April, the month with the lowest electricity sales.

Comparing monthly residential peak loads provided an interesting lesson (Figure 3-2). The average error in monthly peak MW was 8.8%. A large error was observed for April, when the model overestimated peak by 41.3%. In fact, April recorded the lowest peak of any month, but the day of the peak was one of the first summer-like days of the year. While the model expected significant air-conditioning use, people apparently opened their windows instead. This phenomenon was observed previously when simulating the Detroit Edison Company (Pignone, 1984). Excluding the month of April, the mean absolute percent error (for 11 months) in peak load was 5.9%. The error on the annual peak day (in July) was -7.9%.

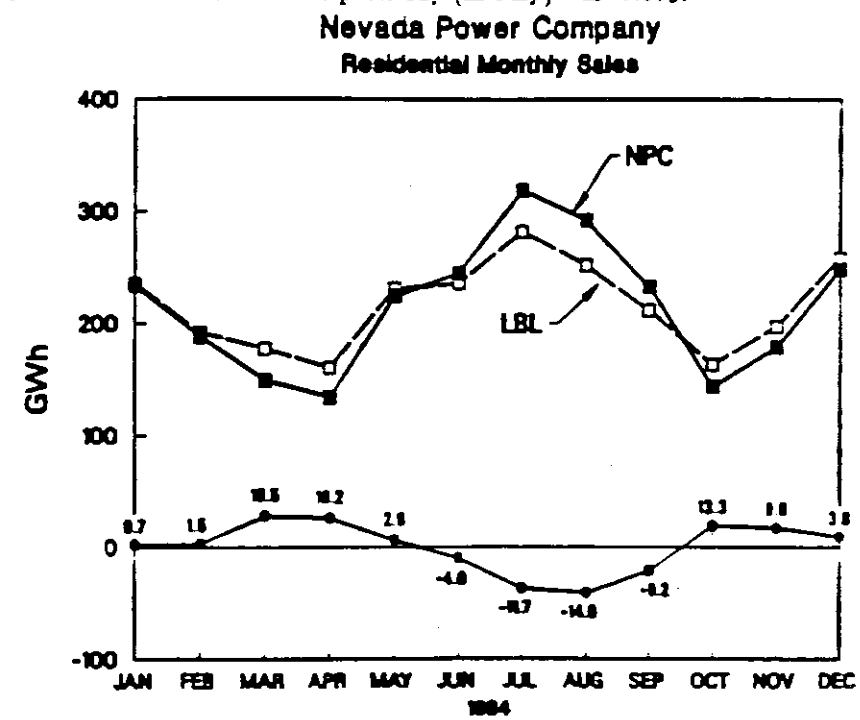


Figure 3-1 Comparison of LBL backcast and NPC recorded monthly residential sales for 1984.

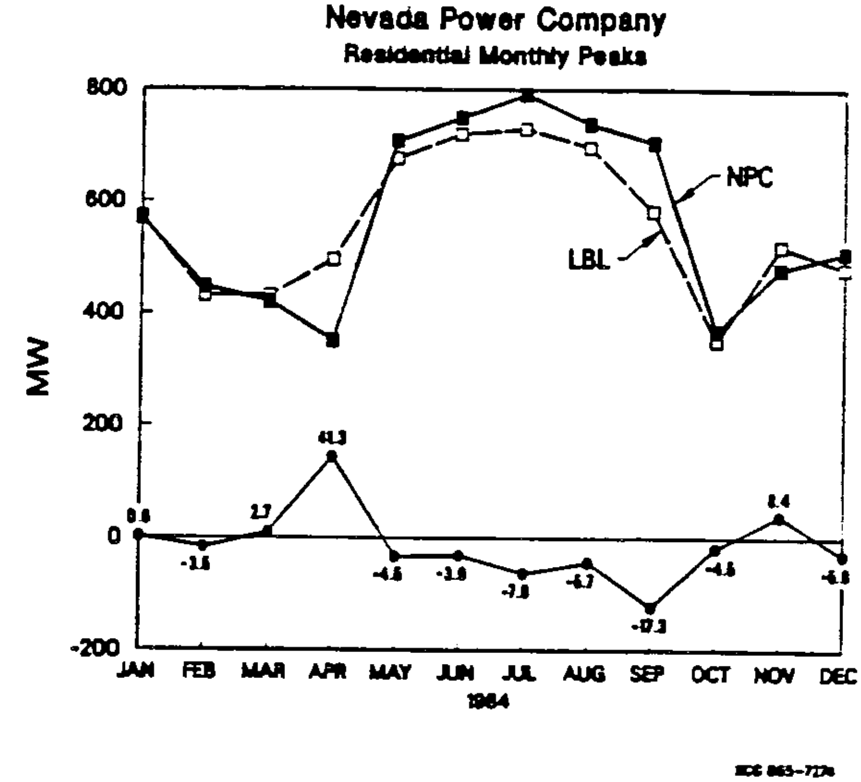


Figure 3-2 Comparison of LBL backcast and NPC recorded monthly residential peak demands for 1984.

### 3.2.4 Hourly Load Shapes

Daily load shapes for the twelve monthly peak days in 1984 were compared with model estimates. We adjusted the thermostat settings in the LBL Residential Hourly Load and Peak Demand Model to improve the fit between model estimates and reported load curves. The best fit (by visual analysis, no statistics were calculated) was obtained with a shift of the temperature scale of +13 degrees F, relative to the original time-temperature matrix. This result is consistent with results obtained for the Pacific Gas and Electric Company (Eto, 1984a). For both utilities, the climate is hot and dry relative to the humid climate of the Northeast U.S. in which the original matrix was derived. As a consequence, thermostat set-points are higher in the dry climates, meaning that air conditioning is not required (less than 10% of capacity in stock) until temperatures are at least in the 80's in dry climates, compared to 70 degrees F in humid climates. At the top end of the temperature scale, in dry climates, full utilization (over 95%) of the air-conditioning capacity in the housing stock occurs at temperatures over 106, while in humid climates, full utilization occurs at temperatures around 93 degrees.

On the heating side, the temperature set-points which give good agreement with observed loads do not differ markedly across the country. For NPC, we found that the lower heating set-point, about 3 degrees F, resulted in the best fit to recorded data.

Peak day hourly load profiles were analyzed for monthly peak days in 1984. The winter peak day (January 18) reported load profile had a peak at 8AM, and a secondary peak at 6PM (see Figure 3-3). The overall shape of the load profile is duplicated by the model. Heating dominates the load shape, with significant contributions to the shape from lighting. The model simulates the morning peak reasonably well, but overestimates the secondary peak in the hours 6-8PM. The model simulation also overestimates the load in midday (9A-4PM), and slightly underestimates the load in the early morning hours. Given the uncertainties in the end-use load profiles, and particularly the lack of information for the miscellaneous end-use, the differences between the model and reported load profile are not surprising. We are pleased that the daily peak is matched rather well.

The summer peak day profile from the model gives better agreement with actual data than the corresponding winter peak day profile. (see Figure 3-4). 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 perhaps 75% of the peak load.

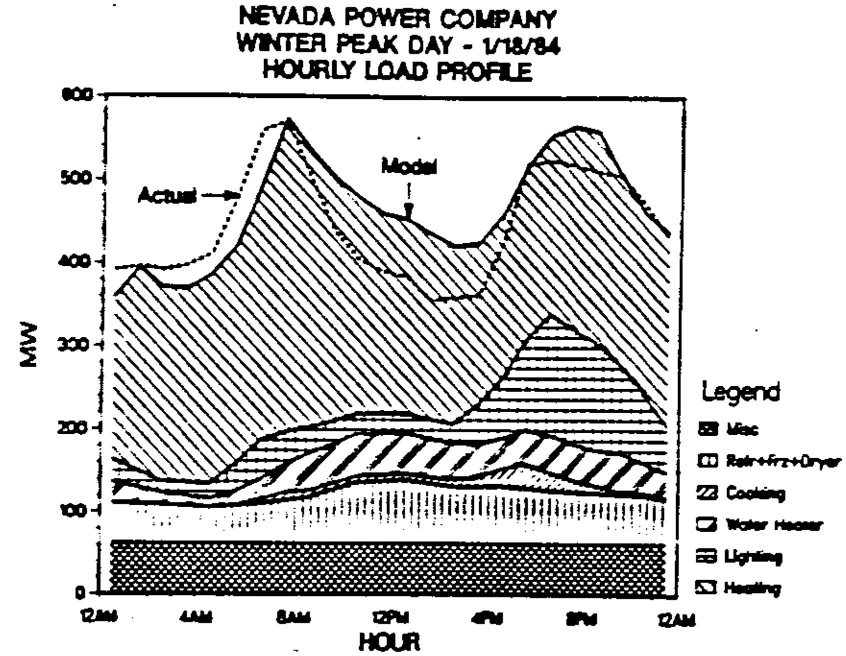


Figure 3-3 Comparison of LBL backcast winter peak day hourly load profile with NPC recorded loads for 1984.

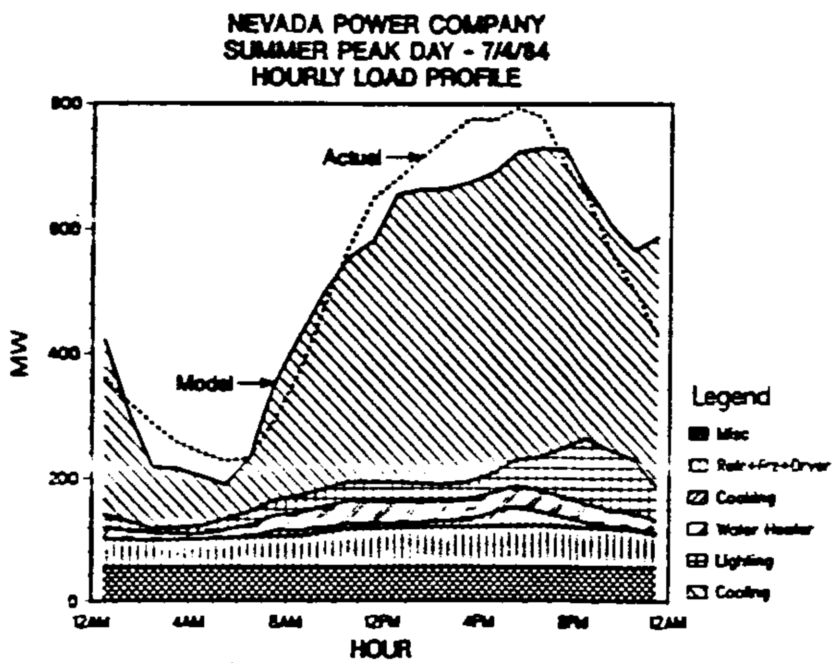


Figure 3-4 Comparison of LBL backcast summer peak day hourly load profile with NPC recorded loads for 1984.

## 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 mandated by the standards were reviewed in Section 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.

In the base case, residential electricity sales are expected to grow from 2,840 GWh in 1986 to 3,730 GWh in 1996 (see Figure 3-5). Two policies produce approximately the same reduction in sales growth, to 3,450 GWh, namely, Level 8 standards, and Level 12/AC standards. The Level 8/12 standard reduces sales in 1996 to 3,350 Gwh.

Examination of the projected peak demand gives a different picture of the effects of the policies (see Figure 3-6). Residential peak demand in the base case is expected to grow from 805 MW in 1986 to over 1,020 MW by 1996. Level 8 standards reduce the 1996 peak to 920 MW. The Level 12/AC standard, while saving approximately the same amount of energy as the Level 8 standards case, reduces load growth much more, to 801 MW in 1996. Level 8/12 achieves only a slight additional decrease in load growth, to 788 MW in 1996, compared to Level 12/AC.

Average sales per customer are expected to decline slightly over time in the base case (see Figure 3-7). The decrease is due to increasing equipment efficiency and tighter building shells. Implementation of either the Level 8 or Level 12/AC standards reduce sales per customer by an additional 6.3% from the base case to about 12,000 kWh/yr in 1996. The Level 8/12 standard reduces per customer sales to about 11500 kWh/yr in 1996.

The seasonal effects of the policies is shown in Figure 3-8. For all cases, sales are reduced more in the summer months than in other seasons. For the Level 8 standards, sales are reduced approximately 4% in winter and 9% in summer. For the Level 12/AC case, sales are not reduced in winter, but are reduced 16% in summer. For the Level 8/12 case, winter sales are reduced approximately 5%, and summer sales are reduced 18%.

The effects on the hourly residential load shape for the summer class peak day in 1996 are shown in Figure 3-9. As expected, the Level 8/12 and Level 12/AC standards yield the largest reduction in loads from the base case. Referring back to Figure 3-4, space cooling is clearly the dominant component of load in the summer.

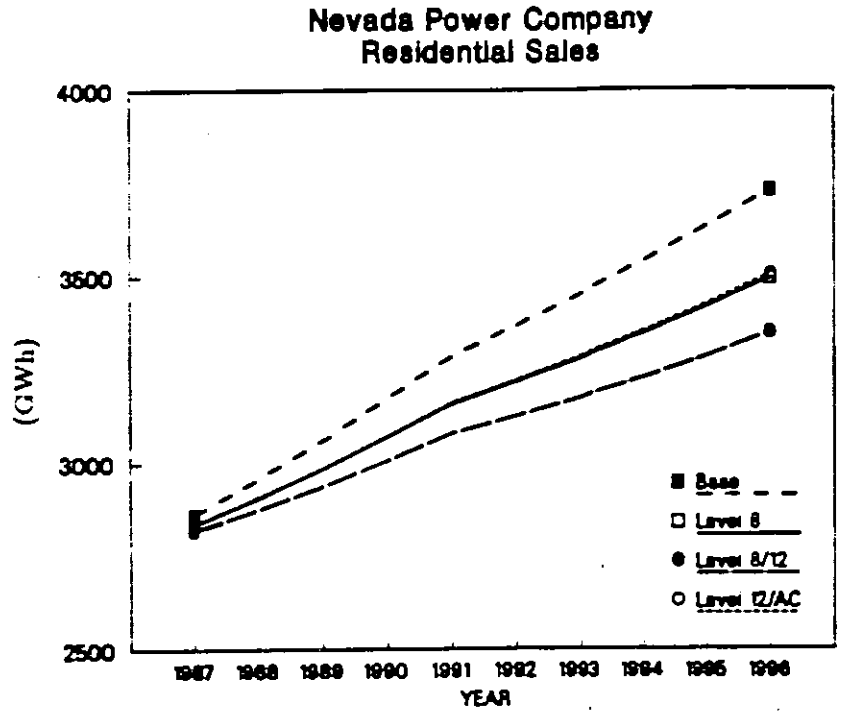


Figure 3-5 LBL forecasts of residential class sales.

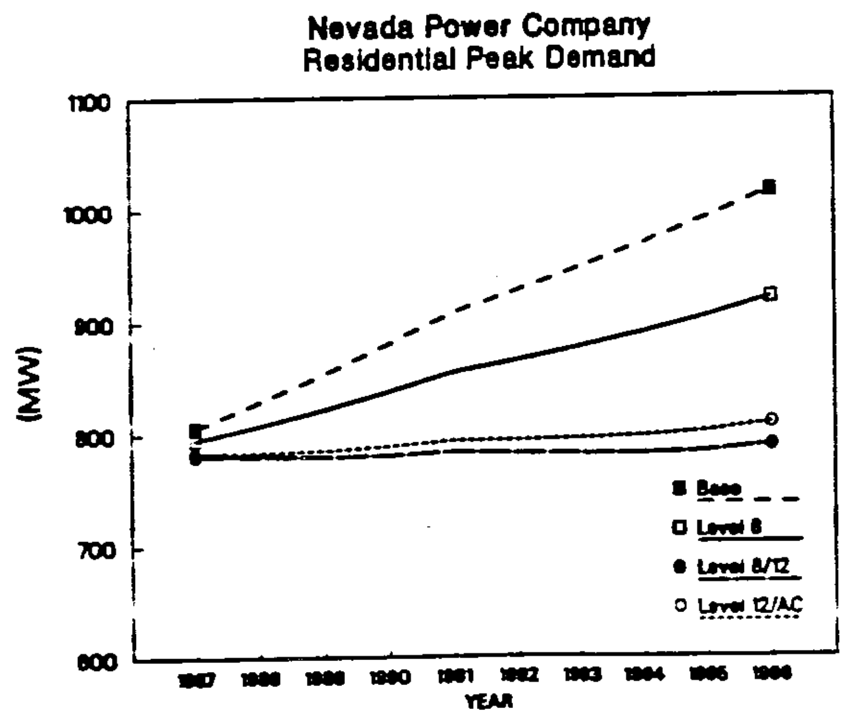


Figure 3-6 LBL forecasts of residential class peak demands.

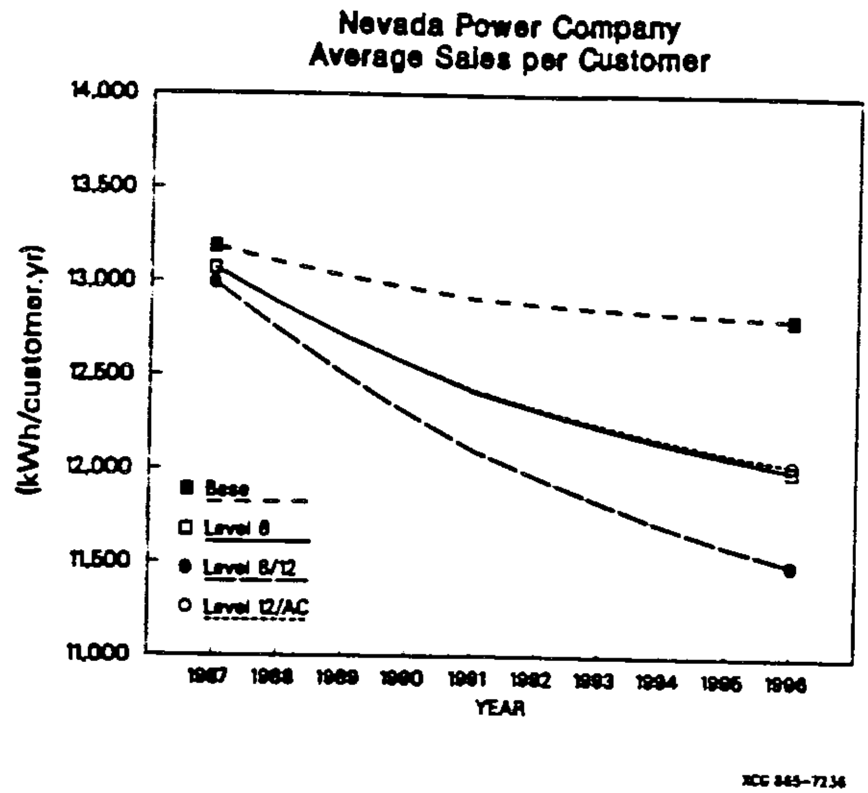


Figure 3-7 LBL forecasts of average annual residential sales.

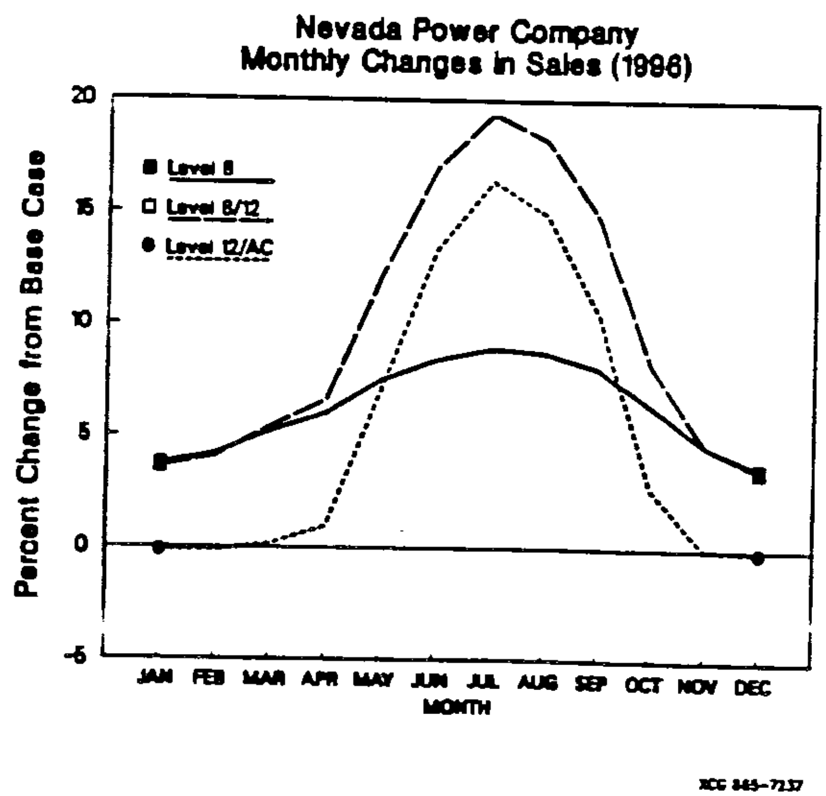


Figure 3-8 Monthly percentage changes in residential sales in 1996.

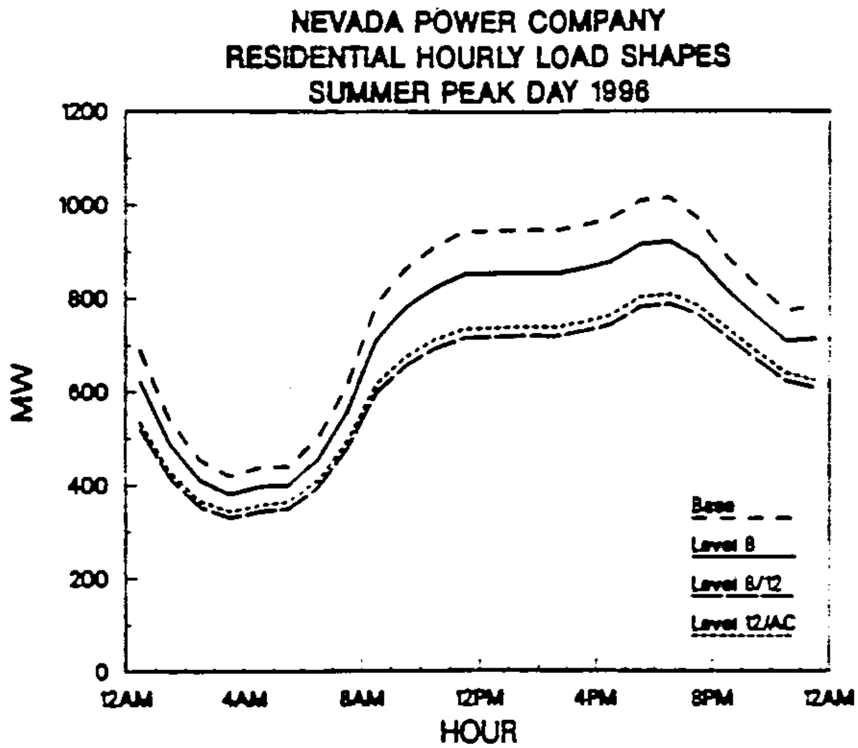


Figure 3-9  LBL forecasts of summer peak day hourly load profiles for 1996.

# 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.

The accuracy of our calculations of avoided electricity generation costs was enhanced by the use of a production-cost model. Production-cost models are used by system planners to develop estimates of future generating system costs under different load and resource assumptions. These costs are calculated by algorithms that simulate the dispatch of generating units by system operators. With few exceptions, the algorithms follow the simple rule that units are dispatched on economic merit; lower variable-cost units are dispatched before higher cost ones.

LBL Integrated Conservation Policy Analysis Method

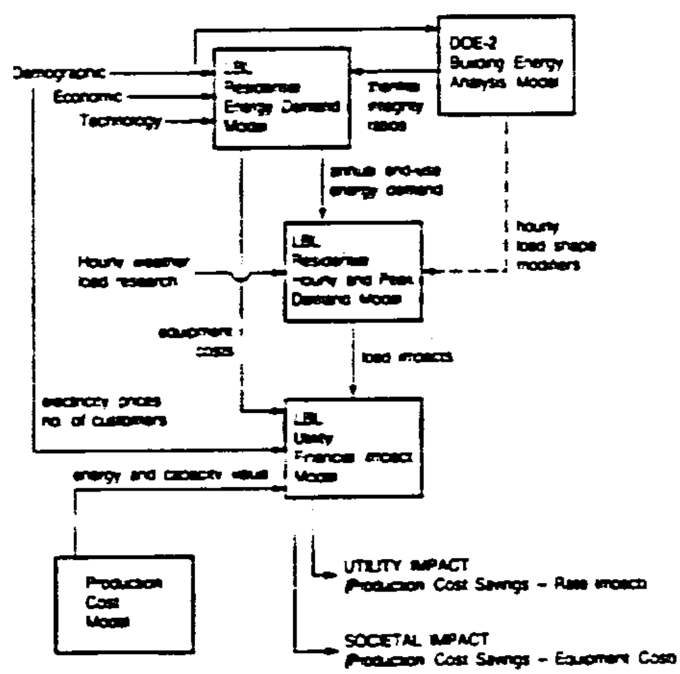


Figure 4-1 LBL Integrated Conservation Policy Analysis Method.

For the NPC case study, we developed two methods for evaluating the avoided production costs resulting from load shape impacts. The first is a measure of short-run marginal costs based on an increment and decrement of hourly system loads. The second is a measure of long-run marginal costs based on the fuel savings resulting from delaying the on-line dates of future units. Section 4.1 describes the assumptions, procedures, and benchmarking results from our efforts to calibrate the production-cost model to NPC data. Section 4.2 motivates and describes the short-run marginal cost and long-run fuel savings calculations and results. Section 4.3 describes the procedures used to apply these results to the load shape changes from our policies.

The cost to the ratepayer is the foregone recovery of the fixed-cost component of rates. 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. This calculation and the resulting ratepayer impacts are described in section 4.4.

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 4.5.

Differing time values of money or discount rates are a fundamental distinction between ratepayer and societal perspectives. For the ratepayer perspective, we used NPC's weighted average cost of capital, 15.07%, to express future benefits and costs in 1986 present-value dollars (NPC, 1984). Societal discount rates are typically lower than private discount rates. We approximate such a rate by using the NPC rate of disadvantage, 11.85%, to present-value the benefits and costs of appliance efficiency standards. The rate of disadvantage is the weighted average cost of capital reduced to account for the tax benefits of debt (Brealy, 1984). Through much of our discussion, we will present results for only the ratepayer perspective. The corresponding tables of intermediate results for the societal perspective are contained in Appendix B.

## 4.1 PRODUCTION-COST SIMULATION WITH TELPLAN

We used the production-cost capabilities of the Telplan utility corporate planning model to develop independent estimates of NPC avoided production costs (Tera 1982). The production-cost component of Telplan relies on probabilistic methods and seasonal load curves to model variable incremental costs, multiple levels of forced outage for generating units, and purchased power/wholesale options.

The first task in using Telplan was to set-up data files for the NPC system and benchmark the results to information supplied by NPC. Data for both inputs and outputs came primarily from the results of NPC's own production-cost modeling efforts. NPC uses the Promod production-cost model developed by Energy Management Associates, Atlanta, GA. Our task was complicated by the decision to combine the results from two related, but distinct Promod runs provided by NPC. An earlier run, M1LM, provided generating unit-specific details that were not available in a later run (NPC, 1985b). The later run, Amended Filing Base Plan, provided an updated load forecast and revised assumptions about resource availability and economic factors (NPC, 1985c).

In this section, we describe the assumptions, procedures, and results from the benchmarking process in four steps: System Loads; Generating Units; Fuel and Purchased Power Costs; and Benchmark Results.

### 4.1.1 System Loads

The representation of system loads is the starting point for all production-cost models. The two central issues are the representation of loads both within a year and over time (total annual energy and peak demands). Differences between models generally center around the first issue.

Both Telplan and Promod rely on load duration curves to simulate the dispatch of generating units. A load duration curve (LDC) is simply a re-ordering of chronological loads in descending order from highest to lowest. This representation, while computationally efficient can mask important details affecting the dispatch and reliability of generating units. For example, forced outages in one hour can not be related to forced outages in the following (chronological) hour. More practically, units that exhibit seasonal behavior (e.g., run-of-river hydro units are generally available only in spring and summer) cannot be represented in an annual LDC. Promod and Telplan address the latter issue by permitting more than one LDC (i.e., seasonal or monthly LDCs) for each year of the simulation.

NPC's Promod simulations use 12 such LDC's and, within each LDC, three sub-periods. Telplan only provides for 4 LDC's and no sub-periods. Thus, the task of reconciling the load representations was one of combining the Promod data into four seasons. Our approach was to group months together based on loss-of-load-probabilities. Loss-of-load-probability (LOLP) is the standard utility industry yardstick for measuring system reliability (Bhavaraju, 1982).

Table 4-1 summarizes selected LOLP results from the more recent Promod run, Amended Filing Base Plan. The years were selected to span a range of system reliabilities corresponding to the base year (1985), the year Hunter 3 goes on-line (1988), and the years before and after White Pine 1 goes on-line (1992 and 1993). LOLP's are highest in the summer months and lowest in the winter months. June and September appear to be shoulder seasons. Based on this evidence, we selected January through May, June and September, July and August, and October through December to be our four seasons. These divisions are indicated in Table 4-1 by horizontal lines separating these months.

Table 4-1. Selected Reliability Results for Nevada Power Company

(Loss of Load Hours per Month)

| | 1985 | 1988 | 1992 | 1993 | Season |
|---|---|---|---|---|---|
| Jan | 0.321 | 0.336 | 4.039 | 6.374 | 1 |
| Feb | 0.152 | 0.180 | 1.609 | 3.877 | 1 |
| Mar | 0.262 | 0.083 | 2.392 | 2.223 | 1 |
| Apr | 0.064 | 0.026 | 0.265 | 0.727 | 1 |
| May | 0.227 | 0.125 | 3.907 | 2.193 | 1 |
| Jun | 91.012 | 45.344 | 45.952 | 69.326 | 2 |
| Jul | 328.359 | 184.487 | 212.148 | 261.371 | 3 |
| Aug | 270.755 | 131.864 | 152.844 | 199.037 | 3 |
| Sep | 92.996 | 14.981 | 15.548 | 25.358 | 2 |
| Oct | 2.366 | 1.063 | 5.171 | 5.794 | 4 |
| Nov | 1.438 | 0.459 | 6.816 | 3.844 | 4 |
| Dec | 2.458 | 1.133 | 11.584 | 6.711 | 4 |

Source: Nevada Power Company, Amended Filing Base Plan; 7/26/85

The next step was to re-express the grouped monthly loads in the appropriate format for Telplan. Telplan accepts a 50-point, normalized load input file for each season. Promod accepts twelve weeks of chronological hourly loads. Telplan loads are represented by a pair of inputs describing the size and duration of a load-point. Formally:

$$LOAD_{ij} = (Load_{ij} - Mean_i) / (Peak_i - Mean_i)$$

where:

LOAD = normalized load
Peak = Peak demand in season i
Load = Load
Mean = Mean load in season i

and

$$LHRS_{ij} = Hour_{ij} / Total\ Hours_i$$

where:

LHRS = normalized hours
Hour = hours at $Load_{ij}$
Total Hours = total hours in season i

A consequence of this form of representation is that the load shape is essentially fixed over the study period. That is, the normalized loads are simply weighted up (or down) annually by a forecast of total energy and peak demand. A potential short-coming of this definition can be a loss of precision in representing minimum loads.

We wrote a FORTRAN pre-processing program to convert the NPC load information developed for Promod to the Telplan format. The program allows the user to specify the aggregation of twelve typical weeks of information to four seasons. The system loads used to develop the normalized load shape were taken from the Native Load and Net Transaction Capacity report from the Amended Filing Base Plan for 1985. Data on projected seasonal energy use and peak demands were also taken from this report. Figures 4-2 through 4-5 compare the NPC load data developed for Promod simulations and the resulting Telplan representation for each Telplan season.

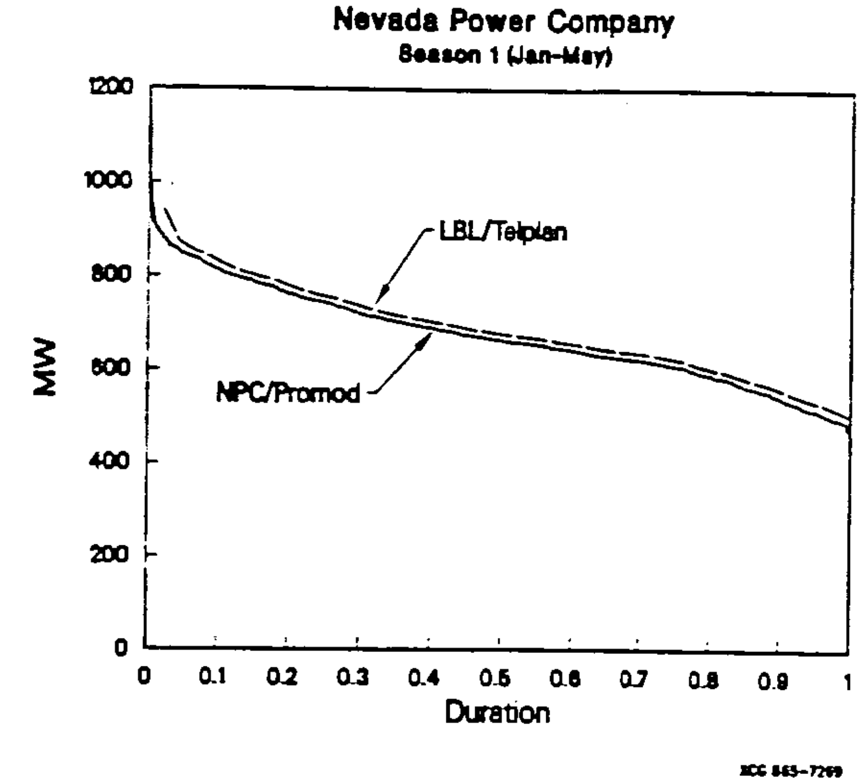


Figure 4.2 Comparison of original (NPC/Promod) to re-expressed (LBL/Telplan) load duration curve for season 1, January through May.

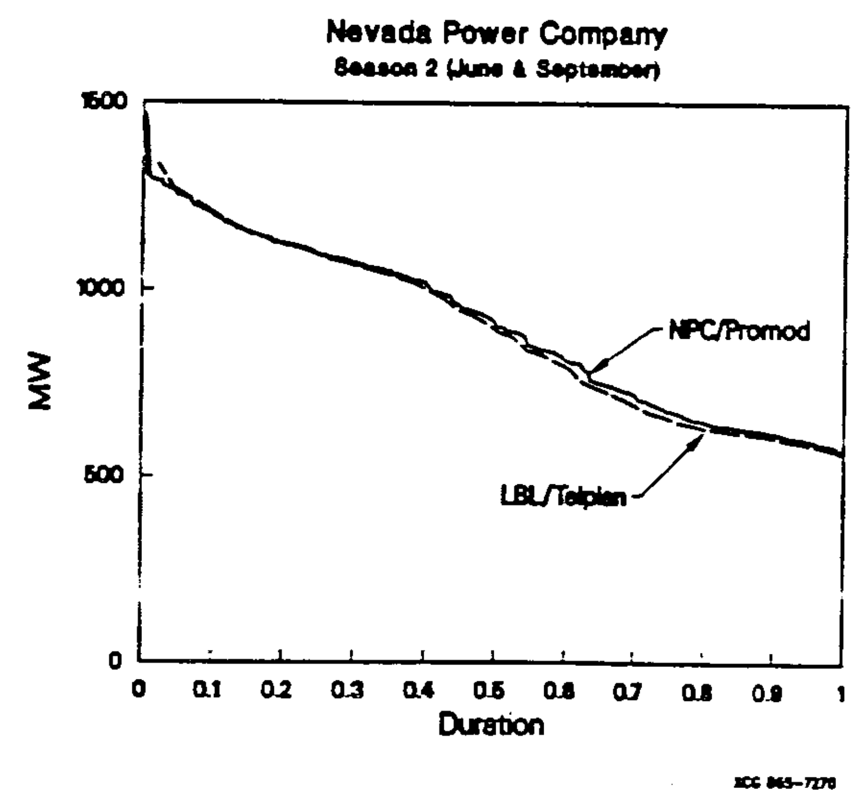


Figure 4.3 Comparison of original (NPC/Promod) to re-expressed (LBL/Telplan) load duration curve for season 2. June and September.

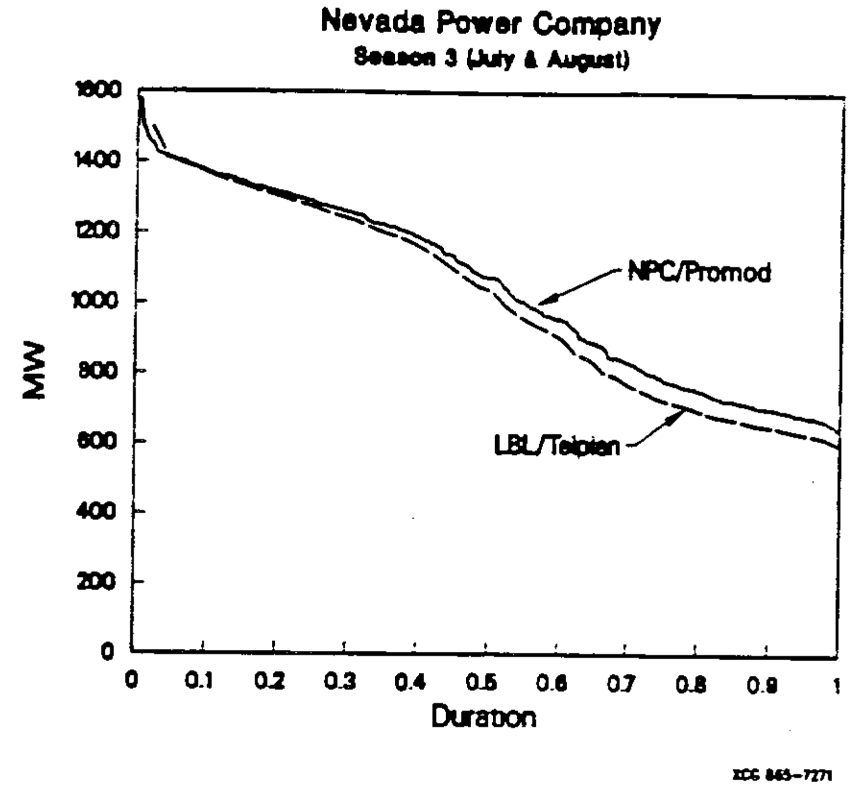


Figure 4.4 Comparison of original (NPC/Promod) to re-expressed (LBL/Telplan) load duration curve for season 3, July and August.

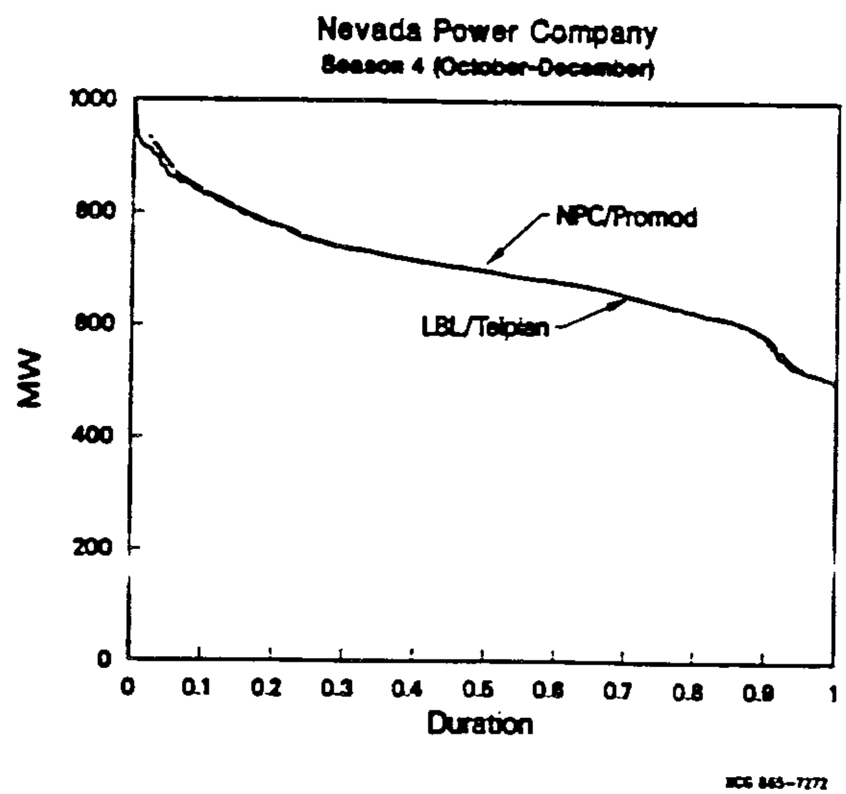


Figure 4.5 Comparison of original (NPC/Promod) to re-expressed (LBL/Telplan) load duration curve for season 4, October through December.

### 4.1.2 Generating Units

We summarize the input assumptions used to describe NPC's generating resources for the benchmarking process on Table 4-2. These data were taken from the Generating Units Characteristics reports produced by Promod. In general, we attempted to replicate data from the most recent NPC Promod run, Amended Filing Base Plan, with two notable exceptions.

First, we retained the sub-unit capacity block definitions from the earlier run, MILM. Without these definitions, Telplan treats generating units as a single, undifferentiated block of capacity in a binary mode (all on or all off). Sub-unit capacity blocks allow the program to dispatch the units in discrete blocks of capacity according to a changing variable cost of generation. These definitions are, consequently, more representative of the manner in which system operators dispatch units to meet load. NPC's decision to simplify their generating unit definitions may be related to the next modification.

Second, we avoided the use of the "must-run" designation for base load units. Base load units typically require substantial warm-up periods; they can not be turned on and off instantaneously. This requirement will result in the dispatch of units on seemingly non-economic grounds. For example, if it is anticipated that a unit will be needed to serve loads during a hot summer afternoon, it will be kept running the previous night, despite the fact that running at night is more expensive vis-a-vis other sources of power available to the dispatcher. Of course, in the load duration curve representation of loads, chronology has been suppressed and so this constraint must be imposed by the modeller. Both Telplan and Promod provide for the designation of units as must-runs to force the dispatch of units at all times, despite the apparent dis-economy of this decision.

NPC's decision to use the must-run designation for all of its base load units is puzzling because the variable cost and size of loads met by the units generally requires that the model will run most base load units full-out for large parts of the year, independent of the must-run designation. Having made an entire unit a must-run unit does explain why it is unnecessary to specify sub-unit capacity blocks: the unit is never allowed to run below full-out. Of course, it is generally possible to specify only the first capacity block as must-run, which is the typical manner in which plants are actually run during low load conditions.

Our reason for avoiding the must-run designation was two-fold. First, we wanted to assure ourselves that the specification was unnecessary for the reason just listed. Second, we didn't want to place too many constraints upon the dispatching algorithms when it came to evaluating avoided production costs. Both our calculation of short-run marginal costs and long-run fuel savings from plant deferral required that the characterization of the system be perturbed from NPC's forecasted operating conditions. Constraints might obscure the cost differences that our perturbations are designed to elicit.

We did, however, retain the must-run designation for the White Pine units in order to address unique features of NPC's agreements to take power from this unit. NPC's share of capacity and energy from this plant, which is slated to come on-line in 1993 and 1994, is fixed by contract with the developer of the plant, the Los Angeles Department of Water and Power. Under the terms of agreement, the variable cost of power from the plant contains a provision for recovery of the fixed costs of the plant. On economic merit, such a plant would not be dispatched until later in the loading order due to the apparent high cost of power from the plant. In fact, the variable cost from this plant are low and some of NPC's allocation of power from the plant is based on take-or-pay contracts. The must-run designation insures that power will be taken from the plant.

Not all of NPC's Promod inputs were incorporated directly into our Telplan simulations. First, NPC specifies a generic purchase of power in every year of their simulation. The purchase is represented by a series of hypothetical generating units that have a lifetime of one year. We have followed the convention of representing these units as generating plants, but have specified only a single unit whose capacity is rerated from year to year. In addition, we had to adjust the planned outage rate of this source of power seasonally in order to fine-tune the level of generation.

Table 4-2. Nevada Power Company Generating Unit Characteristics

| Name | Type | On-line Date | Fuel | Capacity (MW) | Number of Blocks | Forced Outage Rate | Planned Outage | Must-Run | Notes |
|---|---|---|---|---|---|---|---|---|---|
| Clark 1 | ST | 1955 | Gas | 42 | 4 | 15.0 | None | No | |
| Clark 2 | ST | 1957 | Gas | 69 | 4 | 15.0 | Summer derate 4.3 % | No | |
| Clark 3 | ST | 1961 | Gas | 70 | 4 | 15.0 | Summer derate 4.3 % | No | |
| Clark 4 | GT | 1973 | Gas | 59 | 3 | 10.0 | Summer derate 15.3% | No | |
| Clark 5 | GT | 1979 | Gas | 78 | 3 | 10.0 | Summer derate 11.4% | No | |
| Clark 6 | GT | 1979 | Gas | 78 | 3 | 10.0 | Summer derate 11.4% | No | |
| Clark 7 | GT | 1980 | Gas | 78 | 3 | 10.0 | Summer derate 11.4% | No | |
| Clark 8 | GT | 1980 | Gas | 78 | 3 | 10.0 | Summer derate 11.4% | No | |
| Mohave 1 | ST | 1971 | Coal | 111 | 2 | 14.4 | Winter 4 weeks | No | |
| Mohave 2 | ST | 1971 | Coal | 111 | 2 | 14.4 | Winter 4 weeks | No | |
| Navaho 1 | ST | 1974 | Coal | 89 | 2 | 9.1 | Winter 4 weeks | No | |
| Navaho 2 | ST | 1975 | Coal | 89 | 2 | 16.1 | Winter 4 weeks | No | |
| Navaho 3 | ST | 1976 | Coal | 89 | 2 | 17.9 | Winter 4 weeks | No | |
| Reid Gardner 1 | ST | 1965 | Coal | 110 | 3 | 7.6 | Winter 4 weeks | No | |
| Reid Gardner 2 | ST | 1968 | Coal | 110 | 3 | 7.4 | Winter 4 weeks | No | |
| Reid Gardner 3 | ST | 1976 | Coal | 110 | 3 | 12.5 | Winter 4 weeks | No | |
| Reid Gardner 4 | ST | 1983 | Coal | 24 | 2 | 9.1 | Winter 4 weeks | No | Rerated to 95 MW by 2003 |
| Reid Gardner 4 Pk | EP | 1983 | | 226 | 1 | 0.0 | None | No | Rerated to 145 MW by 2003 |
| Sunrise 1 | ST | 1964 | Gas | 80 | 4 | 10.0 | None | No | |
| Sunrise 2 | ST | 1974 | Gas | 76 | 3 | 10.0 | None | No | |
| Westside | ST | 1963 | Oil | 30 | 2 | 8.2 | None | No | |
| Hoover | EP | 1937 | | 100 | 1 | 2.0 | None | No | Rerated to 235 MW by 1995 |
| Generic Purchase | CP | 1986 | | 200 | 1 | 1.0 | None | No | Rerated annually |
| Hunter 3 | ST | 1988 | Coal | 100 | 3 | 25.0 | None | No | Planned outage in FOR |
| Geothermal | EP | 1992 | | 10 | 1 | 0.0 | None | Yes | |
| White Pines 1 | CP | 1993 | | 82 | 1 | 36.2 | None | Yes | Planned outage in FOR |
| White Pines 1 NPC | ST | 1993 | Coal | 30 | 3 | 36.2 | None | Yes | Planned outage in FOR |
| White Pines 2 | CP | 1994 | | 82 | 1 | 36.2 | None | Yes | Planned outage in FOR |
| White Pines 2 NPC | ST | 1994 | Coall | 30 | 3 | 36.2 | None | Yes | Planned outage in FOR |
| Harry Allen 1 | ST | 1996 | Coal | 1259 | 3 | 17.8 | Winter 4 weeks | No | |
| Harry Allen 2 | ST | 1998 | Coal | 1259 | 3 | 17.8 | Winter 4 weeks | No | |
| Harry Allen 3 | ST | 2000 | Coal | 1259 | 3 | 17.8 | Winter 4 weeks | No | |
| Harry Allen 4 | ST | 2002 | Coal | 1259 | 3 | 17.8 | Winter 4 weeks | No | |

Abbreviations: ST - Steam Turbine
GT - Combustion Turbine
EP - Energy-Limited Purchase
CP - Capacity-Limited Purchase

Source: Nevada Power Company, Amended Filing Base Plan, 10/30/85,
Nevada Power Company, MILM, 6/28/86

Table 4-3. Nevada Power Company Fuel and Purchase Power Costs and Escalation Rates

| Fuels | 1985 Cost | Nominal Escalation Rate (%/yr) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($/MBtu) | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 |
| Natural Gas | 4.18 | -0.2 | 8.4 | 10.4 | 12.5 | 12.3 | 11.3 | 9.9 | 8.9 | 8.4 | 9.9 | 11.1 | 11.0 | 9.2 | 8.5 |
| Fuel Oil #2 | 6.05 | 8.7 | 8.9 | 8.1 | 8.3 | 10.5 | 10.0 | 10.0 | 9.3 | 8.5 | 8.9 | 9.3 | 9.7 | 8.8 | 9.1 |
| Mohave Coal | 1.09 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 |
| Navajo Coal | 0.93 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 7.3 | 7.3 | 7.3 | 7.3 | 7.3 | 7.3 | 7.3 | 7.3 | 7.3 |
| Reid Gardner Coal | 2.26 | 5.8 | 6.2 | 6.5 | 6.8 | 7.6 | 7.4 | 7.1 | 7.1 | 7.0 | 7.0 | 7.0 | 7.2 | 7.1 | 7.4 |
| Hunter Coal | 1.36 | 6.0 | 4.9 | 5.7 | 6.3 | 6.9 | 7.2 | 6.9 | 6.6 | 6.7 | 6.5 | 6.4 | 6.5 | 6.8 | 6.6 |
| White Pines Coal | 4.00 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 8.8 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 |
| Harry Allen Coal | 2.11 | 5.5 | 5.4 | 7.4 | 7.1 | 7.7 | 7.6 | 7.2 | 7.1 | 7.0 | 7.0 | 7.1 | 7.3 | 7.2 | 7.4 |
| Purchases | (mills) | | | | | | | | | | | | | | |
| Reid Gardner Pk | 67.3 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 |
| Hoover | 6.5 | 0.0 | 75.4 | 22.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Generic Purchase | 47.7 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 |
| Geothermal | 42.4 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 |
| White Pines | 91.3 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 | 6.0 |

Source: Nevada Power Company, Amended Filing Base Plan, 10/20/86

Second, NPC appears to use forced outage rates to account for both forced and *planned* outages for future generating units. Existing units are specified with a separate planned and forced outage rate: new units appear to be represented by only a forced outage rate. These rates are higher than might be suggested by the technology type and so we concluded that they also incorporate a planned outage rate. NPC's motivation for this convention is not clear. Including planned outages in a forced outage rate makes NPC generating plants less reliable from a modelling standpoint. Lacking clear direction for an alternative specification (i.e., the actual planned outage rates), we simply adopted NPC's inputs.

Third, Promod specifies the efficiency of generating units with both an average heat rate at the lowest capacity block and incremental heat rates at higher capacity blocks. Telplan requires that efficiencies be specified as average heat rates for the entire capacity block. We developed a simple FORTRAN program to convert heat rates to the form required by Telplan.

Fourth, Promod permits seasonal derating of units, Telplan does not. We represented these derates by adjusting the planned outage rate of the units seasonally, which is, in fact, treated as a derate by Telplan.

#### 4.1.3 Fuel and Purchased Power Costs

We used the Fuel Category and Transaction Input Summary reports produced by the more recent NPC Promod run to develop projections of future fuel and purchased power costs. Fixed costs were not considered since our calculations for avoided costs required us to examine only changes in variable operating costs. Table 4-3 contains NPC's 1985 fuel and purchase power prices, and NPC's nominal escalation rates for each of the generating units.

#### 4.1.4 Benchmark Results

We found that Telplan provided credible estimates of the dispatch of NPC generating units vis-a-vis the Promod results supplied by NPC. Table 4-4 compares the Telplan benchmarking results to the Amended Filing Base Case NPC Promod run. The Table compares the capacity factor of units for selected years. Capacity factor is the ratio of the average hourly production of electricity, to the nameplate rated capacity of the plant. Comparisons of capacity factors indicates the degree to which there is a correspondence in the *dispatch* of units between the two simulation programs. As noted previously, we chose Telplan to study variable costs, so we did not compare total costs.

Comparisons of capacity factors alone can be misleading. For example, results in Table 4-4 for 1996 indicate a large difference between the Promod and Telplan estimates for intermediate oil and gas generating units (30.0 versus 20.9). In this case, the use of capacity factors masks the fact that the actual differences in energy generation by intermediate oil and gas units are small relative to total system generation, typically less than 3 percent. If we assume for the moment that the reason Telplan estimates lower energy generation from intermediate oil and gas units is due solely to there being too much generation by the base load coal units, the capacity factors for intermediate oil and gas would be identical and the base load coal capacity factor would decline only slightly, from 74.3 to 71.0 (and bring the results even closer to the NPC's forecasts).

Our general approach to the benchmarking process was to replicate the Promod results without resorting to year-by-year "adjustments". Telplan allows the user to re-specify capacities and planned outages on an annual basis. This flexibility ensures that, with some diligence, differences between model results can be largely eliminated. Trying to "second-guess" the model would, however, defeat our rationale for using the model in the first place. A static, one-time match with an existing model would not be suitable for the subsequent analysis of avoided production costs. Again, these analyses required that we perturb operating conditions in order to measure avoided production costs.

In this regard, we note that, in fact, NPC does employ a number of one-time adjustments in its simulations. The annual adjustment to the capacity of generic purchases is one such adjustment and we have addressed this issue with a single plant that is rerated annually. A more puzzling adjustment is forced outage rates for selected units that vary annually in future years. We did not replicate these variations but believe that they contribute in part to the mis-matches in level of generation by generating type described above.

Table 4-4. Comparison of LBL and NPC Capacity Factor Estimates

| | 1988 | | 1992 | | 1996 | | 2000 | |
|---|---|---|---|---|---|---|---|---|
| Generation Type | NPC | LBL | NPC | LBL | NPC | LBL | NPC | LBL |
| Base load - Coal | 80.3 | 78.6 | 80.3 | 78.5 | 69.8 | 74.3 | 68.3 | 70.8 |
| Base load - Hoover | 35.4 | 35.4 | 29.3 | 29.3 | 27.5 | 27.5 | 26.1 | 26.1 |
| Intermediate - Coal | 68.4 | 72.8 | 60.6 | 64.8 | 62.5 | 63.6 | 57.4 | 56.5 |
| Intermediate - Oil/Gas | 22.2 | 21.4 | 35.5 | 33.8 | 30.0 | 20.9 | 21.1 | 13.0 |
| Peaking - Oil/Gas | 5.3 | 5.7 | 7.2 | 5.5 | 7.8 | 6.4 | 6.1 | 4.3 |

Definitions:

| Base load - Coal | Intermediate - Coal | Intermediate - Oil/Gas | Peaking - Oil/Gas |
|---|---|---|---|
| Mohave 1 | Reid Gardner 1 | Clark 1 | Clark 4 |
| Mohave 2 | Reid Gardner 2 | Clark 2 | Clark 5 |
| Navaho 1 | Reid Gardner 3 | Clark 3 | Clark 6 |
| Navaho 2 | Reid Gardner 4 | Sunrise 1 | Clark 7 |
| Navaho 3 | Generic Purchase | Sunrise 2 | Westside |
| Hunter 3 | | | |
| White Pines 1 | | | |
| White Pines 1 NPC | | | |
| White Pines 2 | | | |
| White Pines 2 NPC | | | |
| Harry Allen 1 | | | |
| Harry Allen 2 | | | |
| Harry Allen 3 | | | |
| Harry Allen 4 | | | |

Sources: Nevada Power Company, Amended Filing Base Plan, October 30, 1986; LBL Telplan Run, NPCBENCH, February 27, 1986.

## 4.2 AVOIDED PRODUCTION COSTS

An immediate consequence of improved appliance efficiencies is reduced demand for electricity and consequently reduced electricity generation costs. In the short-run, capacity expansion decisions are irreversible and avoided production costs are properly measured by short-run marginal costs. In the long-run, capacity expansion decisions can be modified and avoided production costs must address the possibility that plants may be deferred or, in the limit, cancelled. For NPC, we assumed that the transition from the short-run to the long-run takes place in 1993 when the first of the White Pine generating units is scheduled to come on-line. It is our belief that the nearest term capacity addition (Hunter 3 in 1988) is un-avoidable by the appliance efficiency standards considered in this case study; the standards are modelled to take effect in 1987.

In this sub-section, we describe the calculation of short-run marginal and long-run plant deferral costs using Telplan. We also outline the procedures used to assign these costs to load shape changes. A summary document describes the motivation for these procedures (Kahn, 1986b); the emphasis in the following discussion is on assumptions, mechanics, and intermediate results.

### 4.2.1 Short-Run Marginal Costs

In the short-run, generating resources are fixed and the value of a load shape change is measured by the avoided production costs of existing units. We used the increment/decrement method for calculating short-run marginal costs. See Kahn (1985) for a discussion of the theoretical foundations of the method.

Table 4-5. Comparison of LBL and NPC Forecast of Short-run Marginal Cost (current mills/kWh)

| Year | Season | NPC | LBL | percent difference * |
|---|---|---|---|---|
| 1988 | Jan - May | 33.3 | 36.7 | 10.2 |
| | Jun & Sep | 48.8 | 51.8 | 6.1 |
| | Jul & Aug | 61.8 | 56.7 | -8.2 |
| | Oct - Dec | 43.6 | 47.9 | 9.8 |
| 1990 | Jan - May | 51.7 | 55.6 | 7.5 |
| | Jun & Sep | 63.9 | 67.6 | 5.8 |
| | Jul & Aug | 79.4 | 74.3 | -6.4 |
| | Oct - Dec | 67.0 | 72.0 | 7.4 |
| 1992 | Jan - May | 70.3 | 74.6 | 6.2 |
| | Jun & Sep | 76.1 | 82.6 | 8.6 |
| | Jul & Aug | 89.9 | 89.4 | -0.5 |
| | Oct - Dec | 81.0 | 91.3 | 12.7 |
| 1994 | Jan - May | 77.9 | 67.8 | -13.0 |
| | Jun & Sep | 94.4 | 92.4 | -2.1 |
| | Jul & Aug | 106.6 | 104.9 | -1.5 |
| | Oct - Dec | 79.4 | 89.0 | 12.1 |

* percent difference = 100*(LBL-NPC)/NPC

Sources: NPC Amended Filing Base Plan, 26 July, 1985;
LBL Telplan runs, NPCINCR and NPCDECR, 27 February, 1986.

The increment/decrement method for measuring short-run marginal costs requires iterative simulations of the NPC system. In the first simulation, loads are decreased uniformly, in this case, by 100 MW. In a second simulation, load are increased uniformly by the same amount. In both simulations, the generating resources available to meet these loads were held fixed. Marginal cost is calculated by dividing the difference in total variable cost by the difference in energy produced.

Table 4-5 compares our marginal cost estimates with those calculated by NPC using Promod. The NPC values were calculated monthly; we have grouped and averaged these values according to our earlier definition (see section 4.1.1) to facilitate comparison.

A more accurate measure of avoided production costs would have incorporated the load shape changes from each appliance efficiency standard directly. In this case, we would measure the differences between the base case level of loads and a decrement from this level corresponding to the actual loads avoided by the appliance efficiency standard. Resource constraints precluded us from performing these calculations.

### 4.2.2 Long-Run Plant Deferral Costs

In the long-run, it is essential that the value of potential changes in capacity expansion plans be incorporated in a calculation of avoided production costs. We approximated the response of NPC's capacity expansion plan to our load shape changes by calculating the fuel savings resulting from delaying the on-line dates of future plants by two years. We allocated a portion of these savings to a capacity- or reliability-driven component with a combustion turbine proxy.

As discussed in Kahn (1986b), the optimal deferral period is determined by comparing the present value of variable operating costs in the base case calculated from a simulation in which future plants are deferred and the load shape has been modified by the reduced sales of electricity. If the present value of production costs in this case is the same as that in the base case, then we have found the optimal deferral period. Our tests found that that a two-year deferral period for all plants starting with White Pines 1 in 1993 satisfied this criteria. See Appendix A for additional discussion and documentation of these tests.

We then calculated the fuel savings resulting from a two-year deferral of future plants with two additional Telplan simulations. The first was a slightly altered version of our benchmarked inputs, which we will refer to as the Modified Base Case. The second held loads fixed but delayed the on-line dates for all units for two years, starting with the White Pines units in 1993. This simulation will be referred to as the Deferral Case. In both cases, we fixed the level of generic purchases at 100 MW from 1993 onward.

The difference in total variable costs between the Modified Base Case and the Deferral Case is the long-run fuel savings. Since the NPC simulations covered a planning period that ended in 2003, we extrapolated the differences to produce 30 years of annual differences, which is the assumed lifetime of the delayed plant. We then discounted this stream at both the ratepayer and societal discount rates, as described in section 4.1.

Table 4-6 indicates that total variable costs in the deferral case are actually *less* than those in the base case in the years 1993-1995. The reason is that, due to contractual arrangements, portions of the White Pines Units are expensed on a take-or-pay basis. Variable costs for these units include a component for the recovery of fixed costs, which makes this power very expensive, and these costs are not used in the decision to dispatch the units. In the model, the White Pines Units are treated as must-run units whose variable costs in 1993 are 145.56 mills/kWh. When deferred for two years, the model chooses less expensive plants (from the standpoint of variable operating cost) to supply the energy formerly taken from White Pines and total costs are lower in these early years. In later years, variable costs in the deferral case consistently exceed those in the base case, as expected.

Table 4-6. Fuel Cost Savings from Two-year Deferral of White Pines 1

| Year | Base | Deferral | Deferral - Base | Present Value WACC | Present Value ROD |
|---|---|---|---|---|---|
| 1992 | 331.056 | 331.056 | 0.000 | | |
| 1993 | 408.227 | 384.567 | -23.660 | -7.697 | -9.659 |
| 1994 | 486.017 | 443.143 | -42.874 | -12.121 | -15.648 |
| 1995 | 541.982 | 520.229 | -21.753 | -5.344 | -7.098 |
| 1996 | 562.682 | 607.105 | 44.423 | 9.485 | 12.960 |
| 1997 | 634.274 | 688.467 | 54.193 | 10.055 | 14.136 |
| 1998 | 658.973 | 704.663 | 45.690 | 7.367 | 10.655 |
| 1999 | 729.826 | 781.569 | 51.743 | 7.251 | 10.788 |
| 2000 | 770.101 | 813.816 | 43.715 | 5.324 | 8.149 |
| 2001 | 847.251 | 894.504 | 47.253 | 5.001 | 7.875 |
| 2002 | 883.634 | 930.967 | 47.333 | 4.353 | 7.053 |
| 2003 | 970.689 | 1023.102 | 52.413 | 4.189 | 6.982 |
| Trend (92-03) | 8.19 %/yr | 9.30 %/yr | | | |
| 2004 | 1050.21 | 1118.279 | 68.065 | 4.728 | 8.107 |
| 2005 | 1136.26 | 1222.311 | 86.056 | 5.194 | 9.163 |
| 2006 | 1229.35 | 1336.021 | 106.676 | 5.596 | 10.156 |
| 2007 | 1330.06 | 1460.310 | 130.247 | 5.937 | 11.086 |
| 2008 | 1439.03 | 1596.160 | 157.129 | 6.225 | 11.957 |
| 2009 | 1556.93 | 1744.649 | 187.722 | 6.463 | 12.772 |
| 2010 | 1684.48 | 1906.951 | 222.470 | 6.656 | 13.532 |
| 2011 | 1822.49 | 2084.352 | 261.866 | 6.809 | 14.241 |
| 2012 | 1971.80 | 2278.257 | 306.459 | 6.925 | 14.901 |
| 2013 | 2133.34 | 2490.200 | 356.859 | 7.007 | 15.513 |
| 2014 | 2308.12 | 2721.860 | 413.740 | 7.060 | 16.080 |
| 2015 | 2497.22 | 2975.071 | 477.853 | 7.086 | 16.604 |
| 2016 | 2701.81 | 3251.838 | 550.030 | 7.089 | 17.087 |
| 2017 | 2923.16 | 3554.352 | 631.192 | 7.069 | 17.531 |
| 2018 | 3162.65 | 3885.008 | 722.362 | 7.031 | 17.938 |
| 2019 | 3421.75 | 4246.425 | 824.673 | 6.975 | 18.309 |
| 2020 | 3702.09 | 4641.465 | 939.377 | 6.905 | 18.646 |
| 2021 | 4005.39 | 5073.254 | 1067.865 | 6.822 | 18.951 |
| 2022 | 4333.54 | 5545.212 | 1211.672 | 6.726 | 19.224 |
| Total | | | | 152.166 | 327.989 |

**Sources:** **LBL Telplan run NPCBASE 27 Feb 1986;**
**LBL Telplan run NPC2DFR 27 Feb 1986.**

All figures in millions of dollars. Present values were calculated using both the Nevada Power Company weighted average cost of capital (WACC), 15.07%, and the Nevada Power Company rate of disadvantage (ROD), 11.85%.

Table 4-7. Revenue Requirements for Combustion Turbine Proxy

| Year | Rate Base | Depre-ciation | Required Return | Revenue Requirement | Present Value WACC | Present Value ROD |
|---|---|---|---|---|---|---|
| 1993 | 637.54 | 21.25 | 139.90 | 161.16 | 52.43 | 65.79 |
| 1994 | 616.29 | 21.25 | 135.24 | 156.49 | 44.24 | 57.12 |
| 1995 | 595.04 | 21.25 | 130.58 | 151.83 | 37.30 | 49.54 |
| 1996 | 573.79 | 21.25 | 125.91 | 147.17 | 31.42 | 42.93 |
| 1997 | 552.53 | 21.25 | 121.25 | 142.50 | 26.44 | 37.17 |
| 1998 | 531.28 | 21.25 | 116.59 | 137.84 | 22.23 | 32.14 |
| 1999 | 510.03 | 21.25 | 111.92 | 133.17 | 18.66 | 27.77 |
| 2000 | 488.78 | 21.25 | 107.26 | 128.51 | 15.65 | 23.96 |
| 2001 | 467.53 | 21.25 | 102.60 | 123.85 | 13.11 | 20.64 |
| 2002 | 446.28 | 21.25 | 97.93 | 119.18 | 10.96 | 17.76 |
| 2003 | 425.03 | 21.25 | 93.27 | 114.52 | 9.15 | 15.26 |
| 2004 | 403.77 | 21.25 | 88.61 | 109.86 | 7.63 | 13.08 |
| 2005 | 382.52 | 21.25 | 83.94 | 105.19 | 6.35 | 11.20 |
| 2006 | 361.27 | 21.25 | 79.28 | 100.53 | 5.27 | 9.57 |
| 2007 | 340.02 | 21.25 | 74.62 | 95.87 | 4.37 | 8.16 |
| 2008 | 318.77 | 21.25 | 69.95 | 91.20 | 3.61 | 6.94 |
| 2009 | 297.52 | 21.25 | 65.29 | 86.54 | 2.98 | 5.89 |
| 2010 | 276.27 | 21.25 | 60.63 | 81.88 | 2.45 | 4.98 |
| 2011 | 255.02 | 21.25 | 55.96 | 77.21 | 2.01 | 4.20 |
| 2012 | 233.76 | 21.25 | 51.30 | 72.55 | 1.64 | 3.53 |
| 2013 | 212.51 | 21.25 | 46.63 | 67.89 | 1.33 | 2.95 |
| 2014 | 191.26 | 21.25 | 41.97 | 63.22 | 1.08 | 2.46 |
| 2015 | 170.01 | 21.25 | 37.31 | 58.56 | 0.87 | 2.03 |
| 2016 | 148.76 | 21.25 | 32.64 | 53.90 | 0.69 | 1.67 |
| 2017 | 127.51 | 21.25 | 27.98 | 49.23 | 0.55 | 1.37 |
| 2018 | 106.26 | 21.25 | 23.32 | 44.57 | 0.43 | 1.11 |
| 2019 | 85.01 | 21.25 | 18.65 | 39.91 | 0.34 | 0.89 |
| 2020 | 63.75 | 21.25 | 13.99 | 35.24 | 0.26 | 0.70 |
| 2021 | 42.50 | 21.25 | 9.33 | 30.58 | 0.20 | 0.54 |
| 2022 | 21.25 | 21.25 | 4.66 | 25.91 | 0.14 | 0.41 |
| Total | | | | | 323.80 | 471.76 |

CT cost (1985 dollars) = 400 \$/kW
inflation rate = 6.0 %/yr
fixed charge rate = 0.2194

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

All figures are in \$/kW. Present values have been calculated using both the Nevada Power Company weighted average cost of capital (WACC), 15.07%, and the Nevada Power Company rate of disadvantage (ROD), 11.85%.

In both the Modified Base Case and the Deferral Case, we fixed the level of generic purchases to ensure comparability between the two runs. NPC's specification of annual variations in the installed capacity of generic purchases appears to be an attempt to balance loads and resources in the years between generating unit additions. We decided to fix the level of generic purchases, rather than make assumptions as to the criteria used by NPC in setting these levels.

To isolate a reliability-driven component in the capacity expansion decision, we also calculated the present value of revenue requirements for a combustion turbine. The difference between this term and the total fuel savings represents the energy-related component of the fuel savings.

The capital cost of the turbine was assumed to be 400 dollars/kW (1985 dollars) and the lifetime of the turbine was assumed to be 30 years. We applied a tax multiplier to the equity components of NPC's weighted average cost of capital to derive a fixed charge rate of 21.94 percent, based on NPC's assumed Federal tax rate of 46%. Table 4-7 summarizes the entire calculation.

To ensure comparability, all quantities were annualized and respread over 30 years with an economic carrying charge. The carrying charge ensures that the annual real dollar values remain constant with respect to inflation, while the present value of the sum of these terms is the same as that for the original stream of revenue requirements. Simple levelization of the present value of revenue requirements results in a stream of declining annual real dollar values that understates the true marginal cost of the investment in future years (NERA 1977). The economic carrying charge was specified to escalate the annual values at the NPC nominal inflation rate (6 percent/yr). Table 4-8 summarizes the resulting streams.

Table 4-8 Progression Stream for Fuel Savings and CT Proxy.

| Year | Rate of Disadvantage (11.85%) | | | | Weighted Average Cost of Capital (15.07%) | | | |
|---|---|---|---|---|---|---|---|---|
| | Energy-Related Fuel Savings | | Combustion Turbine | | Energy-Related Fuel Savings | | Combustion Turbine | |
| | Progression Stream | Present Value | Progression Stream | Present Value | Progression Stream | Present Value | Progression Stream | Present Value |
| 1993 | 160.53 | 160.53 | 30.83 | 30.83 | 89.16 | 89.16 | 27.90 | 27.90 |
| 1994 | 170.16 | 152.13 | 32.68 | 29.21 | 94.51 | 82.13 | 29.57 | 25.70 |
| 1995 | 180.37 | 144.17 | 34.64 | 27.69 | 100.18 | 75.66 | 31.35 | 23.67 |
| 1996 | 191.19 | 136.63 | 36.71 | 26.24 | 106.19 | 69.70 | 33.23 | 21.81 |
| 1997 | 202.66 | 129.49 | 38.92 | 24.87 | 112.56 | 64.20 | 35.22 | 20.09 |
| 1998 | 214.82 | 122.71 | 41.25 | 23.56 | 119.32 | 59.14 | 37.33 | 18.51 |
| 1999 | 227.71 | 116.30 | 43.73 | 22.33 | 126.48 | 54.48 | 39.57 | 17.05 |
| 2000 | 241.37 | 110.21 | 46.35 | 21.16 | 134.06 | 50.19 | 41.95 | 15.70 |
| 2001 | 255.85 | 104.45 | 49.13 | 20.06 | 142.11 | 46.23 | 44.47 | 14.47 |
| 2002 | 271.21 | 98.99 | 52.08 | 19.01 | 150.63 | 42.59 | 47.13 | 13.33 |
| 2003 | 287.48 | 93.81 | 55.20 | 18.01 | 159.67 | 39.23 | 49.96 | 12.27 |
| 2004 | 304.73 | 88.90 | 58.52 | 17.07 | 169.25 | 36.14 | 52.96 | 11.31 |
| 2005 | 323.01 | 84.25 | 62.03 | 16.18 | 179.41 | 33.29 | 56.14 | 10.42 |
| 2006 | 342.39 | 79.85 | 65.75 | 15.33 | 190.17 | 30.66 | 59.51 | 9.60 |
| 2007 | 362.94 | 75.67 | 69.69 | 14.53 | 201.58 | 28.25 | 63.08 | 8.84 |
| 2008 | 384.71 | 71.71 | 73.88 | 13.77 | 213.68 | 26.02 | 66.86 | 8.14 |
| 2009 | 407.79 | 67.96 | 78.31 | 13.05 | 226.50 | 23.97 | 70.87 | 7.50 |
| 2010 | 432.26 | 64.41 | 83.01 | 12.37 | 240.09 | 22.08 | 75.12 | 6.91 |
| 2011 | 458.20 | 61.04 | 87.99 | 11.72 | 254.49 | 20.34 | 79.63 | 6.36 |
| 2012 | 485.69 | 57.85 | 93.27 | 11.11 | 269.76 | 18.74 | 84.41 | 5.86 |
| 2013 | 514.83 | 54.82 | 98.86 | 10.53 | 285.95 | 17.26 | 89.47 | 5.40 |
| 2014 | 545.72 | 51.95 | 104.79 | 9.98 | 303.11 | 15.90 | 94.84 | 4.98 |
| 2015 | 578.46 | 49.24 | 111.08 | 9.46 | 321.29 | 14.65 | 100.53 | 4.58 |
| 2016 | 613.17 | 46.66 | 117.75 | 8.96 | 340.57 | 13.49 | 106.57 | 4.22 |
| 2017 | 649.96 | 44.22 | 124.81 | 8.49 | 361.01 | 12.43 | 112.96 | 3.89 |
| 2018 | 688.96 | 41.91 | 132.30 | 8.05 | 382.67 | 11.45 | 119.74 | 3.58 |
| 2019 | 730.30 | 39.72 | 140.24 | 7.63 | 405.63 | 10.55 | 126.92 | 3.30 |
| 2020 | 774.11 | 37.64 | 148.65 | 7.23 | 429.96 | 9.72 | 134.54 | 3.04 |
| 2021 | 820.56 | 35.67 | 157.57 | 6.85 | 455.76 | 8.95 | 142.61 | 2.80 |
| 2022 | 869.80 | 33.80 | 167.03 | 6.49 | 483.11 | 8.24 | 151.17 | 2.58 |
| Total | | 2456.71 | | 471.76 | | 1034.82 | | 323.80 |

| | ROD | WACC | Units | Source |
|---|---|---|---|---|
| Fuel Savings = | 327.989<br>2928.47 | 152.166<br>1358.63 | Million $/112 MW<br>$/kW | Table 4-6 |
| Combustion Turbine = | 471.76 | 323.80 | $/kW | Table 4-7 |
| Energy-Related Fuel Savings = | 2456.71 | 1034.83 | $/kW | |
| Economic Carrying Charge = | 0.08616 | 0.06534 | | |

Escalation rate = 6.0 %
Term = 30 yr.

## 4.3 VALUATION OF LOAD SHAPE CHANGES

Having calculated appropriate short- and long-run measures of avoided electricity generation costs, we turn now to the specific procedures used to apply these values to the load shape changes described in section 3. The general process is analogous to procedures used to develop power purchase offers to small power producers and cogenerators. The issues center around the lifetime of the appliance standards, the timing of load shape changes relative to the transition from short- to long-run avoided costs, and the measurement of capacity value for the load shape changes.

### 4.3.1 Lifetime of Appliance Standards

Our calculations 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.

### 4.3.2 Timing Issues

We used the analogy of power sales agreement with small power producers to value the incremental load shape changes as, essentially, twelve year contracts to sell power to the utility. We derived the values assigned for each of the twelve years in three stages. First, for the years 1987 through 1992 we valued the load shape changes at the short-run marginal costs. From 1993 onward, we used the energy-related and reliability components of the fuel savings. For all our calculations, we used a system loss factor of 8.15 percent to relate residential class load shape changes to system avoided energy demands (NPC, 1984).

The general form of the valuation is as follows.

$$\text{Value}_{ij} = \text{Delta}_{ij} * \text{Loss factor} * \text{Marginal Cost}_{ij}$$

where:

Value = value of load shape change, year i, season j
Delta = change in kWh sales from base case
Loss factor = 1.0815
Marginal Cost = short- or long-run marginal cost

We assigned the energy-related component of fuel savings to the load shape changes in an analogous fashion. The units of the energy-related component of fuel savings were converted from dollars per kW to dollars per kWh with the projected capacity factor of the White Pines plant (63 percent).

### 4.3.3 Capacity Value of Load Shape Changes

We used the average kW change between the base and policy case to assign the reliability component of the avoided production costs. The average kW change was calculated by averaging the change in loads for the highest 500 hourly residential loads for each year. In this case, a loss factor and an allowance for reserve margins (20%) were used to relate residential loads to system-level impacts.

The logic for considering the highest 500 hourly loads in determining the capacity value of load shape changes encompasses both system operating conditions, and the coincidence of residential and system loads. System operating conditions identify the times when capacity has value to the system. The coincidence of residential and system loads relates the effect of our policies to those times when capacity has value.

Table 4-9. Full-Load Hours for Nevada Power Company Peaking Plants (1986-2003)

| Plant | Inst. Cap. (MW) | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|---|---|---|---|
| Clark 4 | 59 | 1.86 | 5.07 | 6.31 | 6.04 | 5.69 | 5.08 | 0.14 | 0.29 | 0.43 |
| Clark 5 | 78 | 49.12 | 56.90 | 74.37 | 80.12 | 79.07 | 74.02 | 73.07 | 75.55 | 98.13 |
| Clark 6 | 78 | 30.59 | 44.03 | 62.96 | 66.82 | 66.17 | 62.81 | 61.93 | 66.92 | 65.42 |
| Clark 7 | 78 | 15.60 | 27.61 | 30.21 | 52.94 | 52.27 | 36.31 | 37.86 | 51.94 | 48.36 |
| Clark 8 | 78 | 10.40 | 20.14 | 22.69 | 25.03 | 27.28 | 22.31 | 20.61 | 34.83 | 34.75 |
| Westside | 30 | 0.68 | 2.00 | 2.55 | 2.44 | 0.74 | 0.05 | 0.04 | 0.09 | 0.14 |
| Total (GWh) | | 108.25 | 155.75 | 199.09 | 233.39 | 231.22 | 200.58 | 193.65 | 232.34 | 224.65 |
| Full-Load Hours | | 270 | 388 | 496 | 582 | 577 | 500 | 483 | 579 | 560 |

| Plant | Inst. Cap. (MW) | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|---|---|---|---|---|---|
| Clark 4 | 59 | 8.18 | 0.52 | 8.59 | 0.67 | 6.05 | 0.88 | 6.05 | 0.73 | 2.22 |
| Clark 5 | 78 | 78.27 | 68.64 | 86.68 | 63.77 | 68.91 | 58.54 | 62.45 | 49.05 | 52.87 |
| Clark 6 | 78 | 73.90 | 60.71 | 70.35 | 56.58 | 61.34 | 51.33 | 55.61 | 39.22 | 46.89 |
| Clark 7 | 78 | 57.79 | 45.66 | 54.94 | 42.83 | 48.87 | 33.16 | 43.97 | 15.00 | 24.28 |
| Clark 8 | 78 | 47.13 | 32.06 | 45.23 | 22.31 | 39.01 | 17.72 | 25.95 | 11.58 | 16.87 |
| Westside | 30 | 0.34 | 0.18 | 0.44 | 0.24 | 0.54 | 0.35 | 0.69 | 0.28 | 0.60 |
| Total (GWh) | | 285.47 | 207.77 | 266.23 | 186.4 | 225.62 | 161.98 | 194.72 | 115.86 | 143.73 |
| Full Load Hours | | 712 | 518 | 664 | 465 | 563 | 404 | 486 | 289 | 358 |

Source: LBL Telplan Run, NPCBENCH, February 27, 1986.

We used on estimates of the full-load operating hours of the NPC peaking plant class to determine when capacity has value on the NPC system. Full-load hours are closely related to the inverse of the capacity factor. Formally,

$$\text{Full-load hours} = \text{Total energy generation} \,/\, \text{Total installed capacity}$$

Table 4-9 summarizes our calculations of full-load hours for the NPC peaking plant class identified in Table 4-4 from the benchmark Telplan simulations. For the period from 1987 through 1996, it can be seen that the full-load hours fluctuate near 500 hours per year. Based on this evidence, we concluded that the reliability benefits of additional capacity must be related to the load shape changes over at least this many hours per year.

To conclude that the highest 500 ***residential*** class loads can be used to evaluate reliability benefits for the ***system*** required an analysis of the coincidence of residential and system loads. We can measure this relationship with class coincidence factors. A coincidence factor relates the load of a class of customers at the time of system peak demand to the peak demand of the class. A high coincidence factor indicates that class loads are correlated with system peak demands. Formally,

$$\text{Coincidence Factor} = \text{Peak load}_s \,/\, \text{Peak load}_c$$

where:

$\text{Peak load}_s$ = class peak load at time of system peak
$\text{Peak load}_c$ = class peak load

We performed an analysis of NPC residential class coincidence factors, using load data provided by NPC on system and estimated residential class loads for 1984. The results indicate a high degree of coincidence between residential class and system loads (see Table 4-10). We conclude that examining the average change for the highest 500 residential loads provided a good measure of the capacity benefits of the load shape changes.

Table 4-10. Nevada Power Company Residential Class Coincidence Factors

| Month | Coincidence Factor | Residential Load at Time of System Peak (MW) | Day | Hour | Residential Maximum Load (MW) | Day | Hour |
|---|---|---|---|---|---|---|---|
| Jan | 0.920 | 584 | 18 | 19 | 635 | 18 | 8 |
| Feb | 0.898 | 447 | 16 | 19 | 498 | 27 | 7 |
| Mar | 1.000 | 468 | 7 | 7 | 468 | 7 | 7 |
| Apr | 0.977 | 382 | 17 | 19 | 391 | 17 | 18 |
| May | 0.953 | 753 | 24 | 17 | 790 | 30 | 18 |
| Jun | 0.797 | 667 | 1 | 17 | 836 | 28 | 19 |
| Jul | 0.966 | 853 | 6 | 17 | 883 | 5 | 18 |
| Aug | 0.984 | 810 | 9 | 17 | 823 | 9 | 19 |
| Sep | 0.968 | 760 | 6 | 17 | 785 | 10 | 17 |
| Oct | 0.932 | 382 | 10 | 17 | 410 | 8 | 17 |
| Nov | 0.556 | 297 | 10 | 18 | 534 | 28 | 12 |
| Dec | 0.877 | 498 | 14 | 18 | 568 | 14 | 8 |

Source: Nevada Power Company, 1984 Hourly Loads

## 4.4 AVOIDED PRODUCTION COST BENEFITS

Tables 4-11,12,13 summarize the avoided production cost calculations for each policy case. For all our calculations, we continued to use the NPC weighted average cost of capital, 15.07%, to discount our results and express them in 1985 present value dollars.

The format of each table is as follows. For each year, the tables present the total change in energy and capacity value. Recall that, for capacity, we rely on the average change in demand for the highest 500 residential class hourly loads as our measure of system capacity value. 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 is the sum of the two components.

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, is 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, given two policies that save the similar amounts of energy, Level 8 and Level 12/AC, the one that saves more capacity will have a higher value.

Table 4-11. Avoided Production Costs - Level 8 Appliance Standards, All End-Uses
Nevada Power Company

| Year | Energy Savings | | | | Capacity Savings | | | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total (GWh) | Increment (GWh) | Total (M$) | ($/kWh) | Total* (MW) | Increment (MW) | Total (M$) | ($/kWh) | Total (M$) | ($/kWh) |
| 1987 | 24.6 | 24.6 | 7.3 | 0.298 | 8.3 | 8.3 | 1.5 | 0.060 | 8.8 | 0.358 |
| 1988 | 49.5 | 24.9 | 6.7 | 0.270 | 16.4 | 8.1 | 1.6 | 0.065 | 8.4 | 0.336 |
| 1989 | 74.6 | 25.1 | 6.2 | 0.246 | 24.6 | 8.2 | 1.8 | 0.072 | 8.0 | 0.318 |
| 1990 | 100.2 | 25.6 | 5.6 | 0.221 | 32.9 | 8.3 | 2.0 | 0.078 | 7.6 | 0.298 |
| 1991 | 126.3 | 26.1 | 5.0 | 0.193 | 40.8 | 7.9 | 2.0 | 0.078 | 7.1 | 0.271 |
| 1992 | 148.4 | 22.1 | 3.7 | 0.166 | 47.3 | 6.5 | 1.8 | 0.080 | 5.4 | 0.246 |
| 1993 | 170.0 | 21.6 | 3.0 | 0.139 | 53.6 | 6.3 | 1.8 | 0.084 | 4.8 | 0.223 |
| 1994 | 192.3 | 22.3 | 2.9 | 0.128 | 59.7 | 6.1 | 1.6 | 0.073 | 4.5 | 0.201 |
| 1995 | 213.8 | 21.5 | 2.5 | 0.118 | 65.5 | 5.8 | 1.4 | 0.066 | 4.0 | 0.184 |
| 1996 | 235.1 | 21.3 | 2.3 | 0.109 | 70.6 | 5.1 | 1.1 | 0.054 | 3.5 | 0.162 |
| Total | | 235.1 | 45.3 | 0.193 | | | 16.7 | 0.071 | 62.0 | 0.264 |

* Average change over 500 highest hourly loads.

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC weighted average cost of capital (15.07%). See tables 4-8 and 4-14 for the components of these values.

Table 4-12. Avoided Production Costs - Level 12 Cooling End-Uses, Level 8 All Others
Nevada Power Company

| Year | Energy Savings | | | | Capacity Savings | | | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total (GWh) | Increment (GWh) | Total (M$) | ($/kWh) | Total* (MW) | Increment (MW) | Total (M$) | ($/kWh) | Total (M$) | ($/kWh) |
| 1987 | 40.3 | 40.3 | 12.2 | 0.302 | 19.4 | 19.4 | 3.5 | 0.086 | 15.6 | 0.388 |
| 1988 | 80.3 | 40.0 | 11.0 | 0.274 | 38.0 | 18.6 | 3.7 | 0.093 | 14.7 | 0.368 |
| 1989 | 121.4 | 41.1 | 10.2 | 0.249 | 56.5 | 18.5 | 4.1 | 0.100 | 14.3 | 0.348 |
| 1990 | 163.7 | 42.3 | 9.4 | 0.222 | 74.1 | 17.6 | 4.2 | 0.100 | 13.6 | 0.322 |
| 1991 | 205.4 | 41.7 | 8.1 | 0.194 | 90.0 | 15.9 | 4.1 | 0.098 | 12.2 | 0.292 |
| 1992 | 240.8 | 35.4 | 5.9 | 0.166 | 102.5 | 12.5 | 3.4 | 0.096 | 9.3 | 0.263 |
| 1993 | 276.1 | 35.3 | 4.9 | 0.139 | 114.1 | 11.6 | 3.3 | 0.095 | 8.2 | 0.234 |
| 1994 | 312.0 | 35.9 | 4.6 | 0.128 | 125.0 | 10.9 | 2.9 | 0.081 | 7.5 | 0.208 |
| 1995 | 346.9 | 34.9 | 4.1 | 0.118 | 134.7 | 9.7 | 2.4 | 0.068 | 6.5 | 0.186 |
| 1996 | 380.3 | 33.4 | 3.6 | 0.109 | 142.7 | 8.0 | 1.8 | 0.054 | 5.4 | 0.162 |
| Total | | 380.3 | 74.0 | 0.195 | | | 33.4 | 0.088 | 107.4 | 0.282 |

* Average change over 500 highest hourly loads.

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC weighted average cost of capital (15.07%). See tables 4-8 and 4-14 for the components of these values.

Table 4-13. Avoided Production Costs - Level 12 Standards, Cooling End-Uses Only
Nevada Power Company

| Year | Energy Savings | | | | Capacity Savings | | | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total (GWh) | Increment (GWh) | Total (M$) | ($/kWh) | Total* (MW) | Increment (MW) | Total (M$) | ($/kWh) | Total (M$) | ($/kWh) |
| 1987 | 24.6 | 24.6 | 7.6 | 0.310 | 17.5 | 17.5 | 3.1 | 0.127 | 10.8 | 0.437 |
| 1988 | 49.4 | 24.8 | 7.0 | 0.280 | 34.2 | 16.7 | 3.4 | 0.135 | 10.3 | 0.416 |
| 1989 | 74.4 | 25.0 | 6.3 | 0.253 | 50.7 | 16.5 | 3.6 | 0.146 | 10.0 | 0.399 |
| 1990 | 100.0 | 25.6 | 5.7 | 0.225 | 66.2 | 15.5 | 3.7 | 0.145 | 9.5 | 0.370 |
| 1991 | 125.1 | 25.1 | 4.9 | 0.195 | 79.9 | 13.7 | 3.5 | 0.140 | 8.4 | 0.336 |
| 1992 | 146.4 | 21.3 | 3.5 | 0.167 | 90.5 | 10.6 | 2.9 | 0.136 | 6.4 | 0.303 |
| 1993 | 167.0 | 20.6 | 2.9 | 0.139 | 100.2 | 9.7 | 2.8 | 0.136 | 5.7 | 0.274 |
| 1994 | 187.8 | 20.8 | 2.7 | 0.128 | 109.1 | 8.9 | 2.4 | 0.113 | 5.0 | 0.241 |
| 1995 | 207.9 | 20.1 | 2.4 | 0.118 | 116.8 | 7.7 | 1.9 | 0.094 | 4.3 | 0.211 |
| 1996 | 226.1 | 18.2 | 2.0 | 0.109 | 122.7 | 5.9 | 1.3 | 0.073 | 3.3 | 0.182 |
| Total | | 226.1 | 45.0 | 0.199 | | | 28.6 | 0.127 | 73.6 | 0.326 |

* Average change over 500 highest hourly loads.

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC weighted average cost of capital (15.07%). See tables 4-8 and 4-14 for the components of these values.

## 4.5 RATEPAYER IMPACT

The introduction of efficient appliances cannot be achieved without costs. A comprehensive evaluation of the impacts 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 net impact 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. Further, since the avoided variable cost component is properly valued by the short-run marginal costs to the utility, not the average variable cost, only a fraction of these base rate revennes may be lost.

### 4.5.1 Rate Impact Cost

The rate impact cost is the difference between lost revenues and avoided variable operating costs, which we have defined to be the short-run marginal cost of electricity.

Lost revenues are the change in sales between our base case and a given policy case times the average residential retail electricity rate. See Section 3.1.9 for retail electricity rates used in the demand forecasts. In keeping with the assumption of a twelve-year lifetime for the standards, the present values of twelve years of the lost revenue were calculated from the annual per unit values.

Table 4-14 summarizes our estimates of short-run marginal costs for NPC. From 1987 to 1992, these costs were calculated by the increment/decrement method described earlier, applied to the Modified Base Case. From 1993 on, the marginal costs were still calculated by the increment/decrement method but were applied to the Deferral Case. This distinction was made to ensure consistency with the long-run fuel-savings calculations.

Tables 4-15,16,17 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.

Our calculations indicate that the rate impact cost of each policy is not a cost, but a benefit to the utility. The result stems from the fact that short-run marginal costs consistently exceed lost revenues. Therefore, reduced electricity sales are a benefit since these marginal sales not only fail to recover variable costs but fixed costs as well.

It should be noted that a more explicit treatment of rates might alter this conclusion. For example, complete reallocation of the largest rate impact (level 8/12 in 1996) to the residential class would lower average retail rates by approximately 3%. We did not incorporate these effects in our demand forecasts and instead relied upon NPC's projections of retail rates (see Table 3-10).

Table 4-14. Short-Run Marginal Costs for Nevada Power Company

| Year | Season | Increment Energy (GWh) | Increment Cost (Million $) | Decrement Energy (GWh) | Decrement Cost (Million $) | Increment - Decrement Energy (GWh) | Increment - Decrement Cost (Million $) | Marginal Cost Nominal (mills) | Marginal Cost Present Value (WACC mills) | Marginal Cost Present Value (ROD mills) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1987 | 1 | 3017.78 | 69.657 | 2347.13 | 41.717 | 670.65 | 27.940 | 41.66 | 31.46 | 33.30 |
| | 2 | 1566.96 | 40.228 | 1260.80 | 26.030 | 306.16 | 14.198 | 46.37 | 35.02 | 37.07 |
| | 3 | 1826.15 | 54.428 | 1464.40 | 35.652 | 361.75 | 18.776 | 51.90 | 30.20 | 41.49 |
| | 4 | 1868.02 | 46.101 | 1467.65 | 27.493 | 400.37 | 18.608 | 46.48 | 35.10 | 37.15 |
| 1988 | 1 | 3133.81 | 69.557 | 2461.64 | 44.888 | 672.17 | 24.669 | 36.70 | 24.09 | 26.23 |
| | 2 | 1627.23 | 44.806 | 1322.29 | 29.005 | 304.94 | 15.801 | 51.82 | 34.01 | 37.03 |
| | 3 | 1892.14 | 60.126 | 1535.91 | 39.930 | 356.23 | 20.196 | 56.69 | 37.21 | 40.52 |
| | 4 | 1939.93 | 49.484 | 1539.25 | 30.308 | 400.68 | 19.176 | 47.86 | 31.41 | 34.20 |
| 1989 | 1 | 3257.22 | 79.874 | 2583.26 | 50.625 | 673.96 | 29.249 | 43.40 | 24.75 | 27.73 |
| | 2 | 1691.18 | 52.575 | 1387.69 | 34.596 | 303.49 | 17.979 | 59.24 | 33.79 | 37.85 |
| | 3 | 1968.21 | 71.266 | 1611.81 | 48.264 | 356.40 | 23.002 | 64.54 | 36.81 | 41.24 |
| | 4 | 2016.23 | 59.136 | 1615.35 | 35.918 | 400.88 | 23.218 | 57.92 | 33.03 | 37.01 |
| 1990 | 1 | 3388.24 | 97.107 | 2712.47 | 59.555 | 675.77 | 37.552 | 55.57 | 27.54 | 31.74 |
| | 2 | 1759.19 | 61.962 | 1457.10 | 41.527 | 302.09 | 20.435 | 67.65 | 33.53 | 38.64 |
| | 3 | 2052.48 | 84.576 | 1692.41 | 57.816 | 360.07 | 26.760 | 74.32 | 30.84 | 42.45 |
| | 4 | 2097.32 | 72.100 | 1696.14 | 43.203 | 401.18 | 28.897 | 72.03 | 35.70 | 41.15 |
| 1991 | 1 | 3479.95 | 111.617 | 2802.88 | 67.216 | 677.07 | 44.401 | 65.58 | 28.25 | 33.49 |
| | 2 | 1806.80 | 70.186 | 1505.70 | 47.514 | 301.10 | 22.672 | 75.30 | 32.43 | 38.46 |
| | 3 | 2114.72 | 95.879 | 1748.81 | 66.102 | 365.91 | 29.777 | 81.38 | 35.05 | 41.56 |
| | 4 | 2154.10 | 82.905 | 1752.64 | 50.235 | 401.46 | 32.670 | 81.38 | 35.05 | 41.56 |
| 1992 | 1 | 3569.46 | 127.451 | 2891.19 | 76.875 | 678.27 | 50.576 | 74.57 | 27.91 | 34.06 |
| | 2 | 1853.30 | 78.715 | 1553.10 | 53.909 | 300.20 | 24.806 | 82.63 | 30.93 | 37.73 |
| | 3 | 2174.20 | 107.967 | 1803.91 | 74.862 | 370.29 | 33.105 | 89.40 | 33.47 | 40.82 |
| | 4 | 2209.50 | 94.362 | 1807.84 | 57.676 | 401.66 | 36.686 | 91.34 | 34.19 | 41.71 |
| 1993 | 1 | 3659.36 | 145.729 | 2979.80 | 88.942 | 679.56 | 56.787 | 83.56 | 27.18 | 34.11 |
| | 2 | 1899.87 | 91.493 | 1600.66 | 62.631 | 299.21 | 28.862 | 96.46 | 31.38 | 39.38 |
| | 3 | 2201.48 | 122.077 | 1859.36 | 87.670 | 342.12 | 34.407 | 100.57 | 32.72 | 41.06 |
| | 4 | 2265.19 | 106.964 | 1863.34 | 66.727 | 401.85 | 40.237 | 100.13 | 32.57 | 40.88 |
| 1994 | 1 | 3751.47 | 172.753 | 3070.60 | 102.294 | 680.87 | 70.459 | 103.48 | 29.20 | 37.77 |
| | 2 | 1947.46 | 104.166 | 1649.40 | 73.813 | 298.06 | 30.353 | 101.84 | 28.79 | 37.17 |
| | 3 | 2199.97 | 132.782 | 1915.97 | 100.899 | 284.00 | 31.883 | 112.26 | 31.74 | 40.97 |
| | 4 | 2322.15 | 121.016 | 1920.03 | 76.847 | 402.12 | 44.169 | 109.84 | 31.05 | 40.09 |

Table 4-14. cont. Short-Run Marginal Costs for Nevada Power Company

| Year | Season | Increment Energy (GWh) | Increment Cost (Million $) | Decrement Energy (GWh) | Decrement Cost (Million $) | Increment - Decrement Energy (GWh) | Increment - Decrement Cost (Million $) | Marginal Cost Nominal (mills) | Marginal Cost Present Value (WACC mills) | Marginal Cost Present Value (ROD mills) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1995 | 1 | 3846.48 | 196.889 | 3164.31 | 131.301 | 682.17 | 65.588 | 96.15 | 23.62 | 31.37 |
| | 2 | 1996.80 | 120.723 | 1699.71 | 88.488 | 297.09 | 32.235 | 108.50 | 26.66 | 35.41 |
| | 3 | 2275.39 | 154.664 | 1974.46 | 118.266 | 300.93 | 36.398 | 120.95 | 29.72 | 39.47 |
| | 4 | 2380.97 | 141.482 | 1978.63 | 94.380 | 402.34 | 47.102 | 117.07 | 28.76 | 38.20 |
| 1996 | 1 | 3942.89 | 227.990 | 3259.42 | 162.540 | 683.47 | 65.450 | 95.76 | 20.45 | 27.94 |
| | 2 | 2046.94 | 138.741 | 1750.82 | 102.489 | 296.12 | 36.252 | 122.42 | 26.14 | 35.72 |
| | 3 | 2349.59 | 178.880 | 2033.76 | 137.644 | 315.83 | 41.236 | 130.56 | 27.88 | 38.09 |
| | 4 | 2440.68 | 163.222 | 2083.13 | 112.916 | 357.55 | 50.306 | 140.70 | 30.04 | 41.05 |
| 1997 | 1 | 4043.70 | 259.159 | 3358.83 | 180.823 | 684.87 | 78.336 | 114.38 | 21.22 | 29.83 |
| | 2 | 2099.15 | 156.900 | 1804.18 | 118.199 | 294.97 | 38.701 | 131.20 | 24.34 | 34.22 |
| | 3 | 2375.57 | 197.930 | 2095.59 | 156.836 | 279.98 | 41.094 | 146.77 | 27.23 | 38.28 |
| | 4 | 2503.05 | 184.521 | 2100.23 | 127.641 | 402.82 | 56.880 | 141.20 | 26.20 | 36.83 |
| 1998 | 1 | 4146.61 | 261.307 | 3459.34 | 192.289 | 686.27 | 69.018 | 100.57 | 16.22 | 23.45 |
| | 2 | 2152.18 | 161.386 | 1858.20 | 119.673 | 293.98 | 41.713 | 141.89 | 22.88 | 33.00 |
| | 3 | 2483.90 | 212.465 | 2158.48 | 162.862 | 325.42 | 49.603 | 152.43 | 24.58 | 35.55 |
| | 4 | 2566.19 | 187.588 | 2163.12 | 130.099 | 403.07 | 57.489 | 142.63 | 23.00 | 33.26 |
| 1999 | 1 | 4250.82 | 287.935 | 3563.06 | 209.589 | 687.76 | 78.346 | 113.91 | 15.96 | 23.75 |
| | 2 | 2206.53 | 179.414 | 1913.85 | 134.360 | 292.68 | 45.054 | 153.94 | 21.57 | 32.09 |
| | 3 | 2520.53 | 232.513 | 2222.85 | 182.408 | 297.68 | 50.105 | 168.32 | 23.59 | 35.09 |
| | 4 | 2631.27 | 209.182 | 2227.92 | 145.339 | 403.35 | 63.843 | 158.28 | 22.18 | 33.00 |
| 2000 | 1 | 4358.83 | 295.180 | 3669.56 | 228.144 | 689.27 | 67.036 | 97.26 | 11.84 | 18.13 |
| | 2 | 2262.79 | 183.139 | 1971.18 | 139.178 | 291.61 | 43.961 | 150.75 | 18.36 | 28.10 |
| | 3 | 2626.63 | 248.603 | 2289.53 | 190.660 | 337.10 | 57.943 | 171.89 | 20.93 | 32.04 |
| | 4 | 2698.19 | 207.733 | 2294.62 | 150.662 | 403.57 | 57.071 | 141.42 | 17.22 | 26.36 |
| 2001 | 1 | 4446.24 | 324.734 | 3755.77 | 248.489 | 690.47 | 76.245 | 110.42 | 11.69 | 18.40 |
| | 2 | 2307.89 | 204.256 | 2017.32 | 154.618 | 290.57 | 49.638 | 170.83 | 18.08 | 28.47 |
| | 3 | 2655.69 | 269.769 | 2342.73 | 211.482 | 312.96 | 58.287 | 186.24 | 19.71 | 31.04 |
| | 4 | 2752.27 | 234.528 | 2348.52 | 166.397 | 403.75 | 68.131 | 168.75 | 17.86 | 28.12 |
| 2002 | 1 | 4532.85 | 331.918 | 3841.18 | 269.469 | 691.67 | 62.449 | 90.29 | 8.30 | 13.45 |
| | 2 | 2353.11 | 207.398 | 2063.25 | 159.765 | 289.86 | 47.633 | 164.33 | 15.11 | 24.49 |
| | 3 | 2737.51 | 282.364 | 2396.38 | 217.013 | 341.13 | 65.351 | 191.57 | 17.62 | 28.54 |
| | 4 | 2805.89 | 232.449 | 2401.92 | 173.823 | 403.97 | 58.626 | 145.12 | 13.35 | 21.62 |

Sources: LBL Telplan Run, NPCINCR, February 27, 1986
LBL Telplan Run, NPCDECR, February 27, 1986
LBL Telplan Run, NPCINCR2DFR, March 25, 1986
LBL Telplan Run, NPCDECR2DFR, March 25, 1986

Table 4-15. Rate Impact - Level 8 Appliance Standards, All End-Uses
Nevada Power 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 | 2859.9 | 2835.3 | 24.6 | 24.6 | 9.0 | 0.365 | 9.5 | 0.387 | -0.5 | -0.022 |
| 1988 | 2956.5 | 2907.0 | 49.5 | 24.9 | 8.4 | 0.339 | 9.3 | 0.373 | -0.9 | -0.035 |
| 1989 | 3059.2 | 2984.6 | 74.6 | 25.1 | 7.9 | 0.314 | 9.1 | 0.363 | -1.2 | -0.049 |
| 1990 | 3170.0 | 3069.8 | 100.2 | 25.6 | 7.5 | 0.292 | 9.0 | 0.352 | -1.5 | -0.060 |
| 1991 | 3285.0 | 3158.7 | 126.3 | 26.1 | 7.1 | 0.272 | 8.8 | 0.338 | -1.7 | -0.066 |
| 1992 | 3366.2 | 3217.8 | 148.4 | 22.1 | 5.6 | 0.253 | 7.2 | 0.325 | -1.6 | -0.072 |
| 1993 | 3450.2 | 3280.2 | 170.0 | 21.6 | 5.1 | 0.235 | 6.7 | 0.312 | -1.6 | -0.076 |
| 1994 | 3538.1 | 3345.8 | 192.3 | 22.3 | 4.9 | 0.219 | 6.7 | 0.298 | -1.8 | -0.080 |
| 1995 | 3629.5 | 3415.7 | 213.8 | 21.5 | 4.4 | 0.203 | 6.1 | 0.285 | -1.8 | -0.082 |
| 1996 | 3727.7 | 3492.6 | 235.1 | 21.3 | 4.0 | 0.189 | 5.8 | 0.274 | -1.8 | -0.086 |
| Total | | | | 235.1 | 63.8 | 0.271 | 78.3 | 0.333 | -14.5 | -0.062 |

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC weighted average cost of capital (15.07%). Revenues are calculated using the projected NPC retail rate schedule. Avoided variable costs are based on short-run marginal costs calculated from LBL Telplan production cost simulation runs (see Table 4-14). Rate impact is the difference between revenues and short-run marginal costs.

Table 4-16. Rate Impact - Level 12 Cooling End-Uses, Level 8 All Others
Nevada Power 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 | 2859.0 | 2819.6 | 40.3 | 40.3 | 14.7 | 0.365 | 15.9 | 0.394 | -1.2 | -0.029 |
| 1988 | 2956.5 | 2876.2 | 80.3 | 40.0 | 13.5 | 0.339 | 15.2 | 0.380 | -1.7 | -0.042 |
| 1989 | 3059.2 | 2937.8 | 121.4 | 41.1 | 12.9 | 0.314 | 15.2 | 0.369 | -2.2 | -0.055 |
| 1990 | 3170.0 | 3006.3 | 163.7 | 42.3 | 12.4 | 0.292 | 15.1 | 0.357 | -2.7 | -0.065 |
| 1991 | 3285.0 | 3079.6 | 205.4 | 41.7 | 11.3 | 0.272 | 14.3 | 0.343 | -3.0 | -0.071 |
| 1992 | 3366.2 | 3125.4 | 240.8 | 35.4 | 9.0 | 0.253 | 11.7 | 0.329 | -2.7 | -0.076 |
| 1993 | 3450.2 | 3174.1 | 276.1 | 35.3 | 8.3 | 0.235 | 11.2 | 0.316 | -2.9 | -0.081 |
| 1994 | 3538.1 | 3226.1 | 312.0 | 35.9 | 7.9 | 0.219 | 10.9 | 0.303 | -3.0 | -0.084 |
| 1995 | 3629.5 | 3282.6 | 346.9 | 34.0 | 7.1 | 0.203 | 10.1 | 0.290 | -3.0 | -0.086 |
| 1996 | 3727.7 | 3347.4 | 380.3 | 33.4 | 6.3 | 0.189 | 9.3 | 0.279 | -3.0 | -0.090 |
| Total | | | | 380.3 | 103.4 | 0.272 | 128.8 | 0.339 | -25.4 | -0.067 |

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC weighted average cost of capital (15.07%). Revenues are calculated using the projected NPC retail rate schedule. Avoided variable costs are based on short-run marginal costs calculated from LBL Telplan production cost simulation runs (see Table 4-14). Rate impact is the difference between revenues and short-run marginal costs.

Table 4-17. Rate Impact - Level 12 Standards, Cooling End-Uses Only
Nevada Power 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 | 2859.9 | 2835.3 | 24.6 | 24.6 | 9.0 | 0.365 | 10.0 | 0.405 | -1.0 | -0.040 |
| 1988 | 2956.5 | 2907.1 | 49.4 | 24.8 | 8.4 | 0.339 | 9.7 | 0.391 | -1.3 | -0.053 |
| 1989 | 3059.2 | 2984.8 | 74.4 | 25.0 | 7.9 | 0.314 | 9.5 | 0.379 | -1.6 | -0.064 |
| 1990 | 3170.0 | 3070.0 | 100.0 | 25.6 | 7.5 | 0.292 | 9.4 | 0.365 | -1.9 | -0.073 |
| 1991 | 3285.0 | 3159.9 | 125.1 | 25.1 | 6.8 | 0.272 | 8.8 | 0.351 | -2.0 | -0.079 |
| 1992 | 3366.2 | 3219.8 | 146.4 | 21.3 | 5.4 | 0.253 | 7.2 | 0.337 | -1.8 | -0.084 |
| 1993 | 3450.2 | 3283.2 | 167.0 | 20.6 | 4.8 | 0.235 | 6.7 | 0.324 | -1.8 | -0.089 |
| 1994 | 3538.1 | 3350.3 | 187.8 | 20.8 | 4.5 | 0.219 | 6.5 | 0.310 | -1.9 | -0.092 |
| 1995 | 3629.5 | 3421.6 | 207.9 | 20.1 | 4.1 | 0.203 | 6.0 | 0.297 | -1.9 | -0.094 |
| 1996 | 3727.7 | 3501.6 | 226.1 | 18.2 | 3.4 | 0.189 | 5.2 | 0.286 | -1.8 | -0.098 |
| Total | | | | 226.1 | 61.8 | 0.274 | 78.8 | 0.349 | -17.0 | -0.075 |

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC weighted average cost of capital (15.07%). Revenues are calculated using the projected NPC retail rate schedule. Avoided variable costs are based on short-run marginal costs calculated from LBL Telplan production cost simulation runs (see Table 4-14). Rate impact is the difference between revenues and short-run marginal costs.

### 4.5.2 Ratepayer Impact

Tables 4-18,19,20 summarize the ratepayer impacts for each policy case. 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.

Since the rate impact costs are always, in fact, benefits, the ratepayer impacts of the policies are always positive. In absolute terms, the Level 8/12 policy has the highest value, owing to saving the most energy. On a per unit basis, however, the policy targeting peak electrical demands, Level 12/AC, has the highest value. This conclusion results directly from the relatively greater value of the avoided production cost benefits attributable to the policy. That is, since this policy saves relatively more capacity, it is accorded a higher value.

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 benefits result from short-run marginal costs that exceed lost revenues. The lost revenue term is, in turn, a function of projected retail rates. Changes in the level of future retail rates would modify these results. Our decision to simply project rates from NPC information, consequently, deserves closer attention.

Finally, the decision to consider the rate impact as a cost or, in this case, a benefit to the ratepayer relies on an assumption of perfect regulation. In the absence of perfect regulation, the over-collection of costs through revenues will be a benefit to the stockholders of the utility.

Table 4-18. Ratepayer Impact - Level 8 Appliance Standards. All End-Uses
Nevada Power Company

| | 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 | 24.6 | 8.3 | 8.8 | 0.358 | -0.5 | -0.022 | 9.3 | 0.380 |
| 1988 | 24.9 | 16.4 | 8.4 | 0.336 | -0.9 | -0.035 | 9.2 | 0.370 |
| 1989 | 25.1 | 24.6 | 8.0 | 0.318 | -1.2 | -0.049 | 9.2 | 0.367 |
| 1990 | 25.6 | 32.9 | 7.6 | 0.298 | -1.5 | -0.060 | 9.2 | 0.358 |
| 1991 | 26.1 | 40.8 | 7.1 | 0.271 | -1.7 | -0.066 | 8.8 | 0.337 |
| 1992 | 22.1 | 47.3 | 5.4 | 0.246 | -1.6 | -0.072 | 7.0 | 0.318 |
| 1993 | 21.6 | 53.6 | 4.8 | 0.223 | -1.6 | -0.076 | 6.5 | 0.299 |
| 1994 | 22.3 | 59.7 | 4.5 | 0.201 | -1.8 | -0.080 | 6.2 | 0.280 |
| 1995 | 21.5 | 65.5 | 4.0 | 0.184 | -1.8 | -0.082 | 5.7 | 0.265 |
| 1996 | 21.3 | 70.6 | 3.5 | 0.162 | -1.8 | -0.086 | 5.3 | 0.248 |
| Total | 235.1 | 70.6 | 62.0 | 0.264 | -14.5 | -0.062 | 76.5 | 0.325 |

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC weighted average cost of capital (15.07%). Avoided cost benefits were taken from Table 4-11. Rate impact costs were taken from Table 4-15. Net benefit is the difference between the avoided cost benefit and the rate impact cost.

Table 4-19. Ratepayer Impact - Level 12 Cooling End-Uses, Level 8 All Others
Nevada Power Company

| Year | Load Shape Change: Energy (GWh) | Load Shape Change: Capacity (MW) | A Avoided Cost Benefit: Total (M$) | A Avoided Cost Benefit: ($/kWh) | B Rate Impact Cost: Total (M$) | B Rate Impact Cost: ($/kWh) | A - B Net Benefit: Total (M$) | A - B Net Benefit: ($/kWh) |
|---|---|---|---|---|---|---|---|---|
| 1987 | 40.3 | 19.4 | 15.6 | 0.388 | -1.2 | -0.029 | 16.8 | 0.417 |
| 1988 | 40.0 | 38.0 | 14.7 | 0.368 | -1.7 | -0.042 | 16.4 | 0.410 |
| 1989 | 41.1 | 56.5 | 14.3 | 0.348 | -2.2 | -0.055 | 16.6 | 0.403 |
| 1990 | 42.3 | 74.1 | 13.6 | 0.322 | -2.7 | -0.065 | 16.4 | 0.387 |
| 1991 | 41.7 | 90.0 | 12.2 | 0.292 | -3.0 | -0.071 | 15.1 | 0.363 |
| 1992 | 35.4 | 102.5 | 9.3 | 0.263 | -2.7 | -0.076 | 12.0 | 0.339 |
| 1993 | 35.3 | 114.1 | 8.2 | 0.234 | -2.9 | -0.081 | 11.1 | 0.315 |
| 1994 | 35.9 | 125.0 | 7.5 | 0.208 | -3.0 | -0.084 | 10.5 | 0.293 |
| 1995 | 34.9 | 134.7 | 6.5 | 0.186 | -3.0 | -0.086 | 9.5 | 0.272 |
| 1996 | 33.4 | 142.7 | 5.4 | 0.162 | -3.0 | -0.090 | 8.4 | 0.253 |
| Total | 380.3 | 142.7 | 107.4 | 0.282 | -25.4 | -0.067 | 132.8 | 0.349 |

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC weighted average cost of capital (15.07%). Avoided cost benefits were taken from Table 4-12. Rate impact costs were taken from Table 4-16. Net benefit is the difference between the avoided cost benefit and the rate impact cost.

Table 4-20. Ratepayer Impact - Level 12 Standards, Cooling End-Uses Only
Nevada Power Company

| Year | Load Shape Change: Energy (GWh) | Load Shape Change: Capacity (MW) | A Avoided Cost Benefit: Total (M$) | A Avoided Cost Benefit: ($/kWh) | B Rate Impact Cost: Total (M$) | B Rate Impact Cost: ($/kWh) | A - B Net Benefit: Total (M$) | A - B Net Benefit: ($/kWh) |
|---|---|---|---|---|---|---|---|---|
| 1987 | 24.6 | 17.5 | 10.8 | 0.437 | -1.0 | -0.040 | 11.7 | 0.478 |
| 1988 | 24.8 | 34.2 | 10.3 | 0.416 | -1.3 | -0.053 | 11.6 | 0.468 |
| 1989 | 25.0 | 50.7 | 10.0 | 0.399 | -1.6 | -0.064 | 11.6 | 0.463 |
| 1990 | 25.6 | 66.2 | 9.5 | 0.370 | -1.9 | -0.073 | 11.3 | 0.443 |
| 1991 | 25.1 | 79.9 | 8.4 | 0.335 | -2.0 | -0.079 | 10.4 | 0.415 |
| 1992 | 21.3 | 90.5 | 6.4 | 0.303 | -1.8 | -0.084 | 8.2 | 0.387 |
| 1993 | 20.6 | 100.2 | 5.7 | 0.274 | -1.8 | -0.089 | 7.5 | 0.363 |
| 1994 | 20.8 | 109.1 | 5.0 | 0.241 | -1.9 | -0.092 | 6.9 | 0.333 |
| 1995 | 20.1 | 116.8 | 4.3 | 0.211 | -1.9 | -0.094 | 6.1 | 0.306 |
| 1996 | 18.2 | 122.7 | 3.3 | 0.182 | -1.8 | -0.098 | 5.1 | 0.279 |
| Total | 225.1 | 122.7 | 73.6 | 0.326 | -17.0 | -0.075 | 90.6 | 0.401 |

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC weighted average cost of capital (15.07%). Avoided cost benefits were taken from Table 4-13. Rate impact costs were taken from Table 4-17. Net benefit is the difference between the avoided cost benefit and the rate impact cost.

## 4.6 SOCIETAL IMPACT

The cost to society of more efficient appliances is measured by considering the incremental equipment cost of more efficient appliances. The benefits remain the avoided production costs. Before describing these results, we define our calculation of incremental equipment costs and explain the use of a discount rate different from that used in the calculation of ratepayer impacts.

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, changes in per unit costs are applied to the level of purchases in the base case (DOE, 1983).

In evaluating societal impacts it is appropriate to discount costs and benefits at a rate lower than the NPC weighted average cost of capital. We have used the NPC rate of disadvantage for this purpose. The NPC rate of disadvantage is the NPC weighted average cost of capital reduced by the tax benefits on the debt component, 11.85%. Appendix B contains supporting tables for the components of the societal cost calculation using the lower discount rate.

From a societal perspective, only the Level 8 standard yields positive benefits. The Level 8/12 policy has slightly negative impacts, but the Level 12/AC has large negative impacts. Tables 4-21,22,23 summarize the societal impacts. 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 Tables show the equipment cost for the standard. The difference between the avoided production cost benefit and the equipment cost is the net benefit to society.

It is instructive to note the symmetry in the results for the Level 8 and Level 12/AC policy cases. Both policies save similar amount of energy. The cost premium for the Level 12/AC policy, however, is more than three times greater than that of the Level 8 policy. This cost premium does not save more energy, rather it is directed at saving capacity. These additional capacity savings, moreover, only increase the avoided production cost benefits by about twenty percent and are easily outweighed by the cost premium.

There is reason to believe that the cost premium associated with the more efficient appliances may be over-estimated (see Kahn, 1986a). If this overestimate is large, then even the Level 12/AC standard may become cost-effective. Only a small overestimate makes the Level 8/12 standard beneficial to society.

Table 4-21. Societal Impact - Level 8 Appliance Standards. All End-Uses
Nevada Power Company

| | 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 | 24.6 | 8.3 | 11.7 | 0.477 | 7.0 | 0.285 | 4.7 | 0.192 |
| 1988 | 24.9 | 16.4 | 11.6 | 0.467 | 7.1 | 0.285 | 4.5 | 0.182 |
| 1989 | 25.1 | 24.6 | 11.6 | 0.460 | 7.2 | 0.287 | 4.4 | 0.173 |
| 1990 | 25.6 | 32.9 | 11.5 | 0.450 | 7.2 | 0.280 | 4.3 | 0.170 |
| 1991 | 26.1 | 40.8 | 11.2 | 0.429 | 6.9 | 0.263 | 4.3 | 0.166 |
| 1992 | 22.1 | 47.3 | 9.1 | 0.410 | 5.6 | 0.255 | 3.5 | 0.155 |
| 1993 | 21.6 | 53.6 | 8.5 | 0.392 | 5.3 | 0.246 | 3.2 | 0.146 |
| 1994 | 22.3 | 59.7 | 8.1 | 0.365 | 5.1 | 0.227 | 3.0 | 0.138 |
| 1995 | 21.5 | 65.5 | 7.4 | 0.345 | 4.8 | 0.225 | 2.6 | 0.119 |
| 1996 | 21.3 | 70.6 | 6.8 | 0.317 | 4.7 | 0.221 | 2.1 | 0.096 |
| Total | 235.1 | 70.6 | 97.5 | 0.415 | 60.9 | 0.259 | 36.6 | 0.156 |

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 NPC rate of disadvantage (11.85%). Avoided cost benefits were taken from Table 4-11a. 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 4-22. Societal Impact - Level 12 Cooling End-Uses, Level 8 All Others
Nevada Power Company

| | 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 | 40.3 | 19.4 | 20.7 | 0.513 | 24.1 | 0.598 | (3.4) | (0.085) |
| 1988 | 40.0 | 38.0 | 20.2 | 0.505 | 24.5 | 0.611 | (4.3) | (0.106) |
| 1989 | 41.1 | 56.5 | 20.4 | 0.496 | 24.8 | 0.603 | (4.4) | (0.107) |
| 1990 | 42.3 | 74.1 | 20.2 | 0.479 | 24.4 | 0.577 | (4.2) | (0.098) |
| 1991 | 41.7 | 90.0 | 19.0 | 0.455 | 23.3 | 0.560 | (4.3) | (0.105) |
| 1992 | 35.4 | 102.5 | 15.2 | 0.431 | 19.4 | 0.549 | (4.2) | (0.118) |
| 1993 | 35.3 | 114.1 | 14.3 | 0.405 | 18.3 | 0.519 | (4.0) | (0.114) |
| 1994 | 35.9 | 125.0 | 13.5 | 0.375 | 17.6 | 0.489 | (4.1) | (0.114) |
| 1995 | 34.9 | 134.7 | 12.1 | 0.347 | 16.9 | 0.484 | (4.8) | (0.137) |
| 1996 | 33.4 | 142.7 | 10.6 | 0.317 | 16.5 | 0.494 | (5.5) | (0.177) |
| Total | 380.3 | 142.7 | 166.2 | 0.437 | 209.7 | 0.552 | (43.5) | (0.115) |

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 NPC rate of disadvantage (11.85%). Avoided cost benefits were taken from Table 4-12a. 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 4-23. Societal Impact - Level 12 Standards. Cooling End-Uses Only
Nevada Power Company

| 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 | 24.6 | 17.5 | 14.0 | 0.570 | 21.7 | 0.883 | (7.7) | (0.313) |
| 1988 | 24.8 | 34.2 | 13.9 | 0.561 | 22.1 | 0.892 | (8.2) | (0.331) |
| 1989 | 25.0 | 50.7 | 13.9 | 0.557 | 22.5 | 0.898 | (8.6) | (0.341) |
| 1990 | 25.6 | 66.2 | 13.7 | 0.537 | 22.1 | 0.863 | (8.4) | (0.326) |
| 1991 | 25.1 | 79.9 | 12.8 | 0.509 | 21.1 | 0.839 | (8.3) | (0.330) |
| 1992 | 21.3 | 90.5 | 10.2 | 0.481 | 17.6 | 0.826 | (7.4) | (0.345) |
| 1993 | 20.6 | 100.2 | 9.4 | 0.457 | 16.5 | 0.803 | (7.1) | (0.346) |
| 1994 | 20.8 | 109.1 | 8.7 | 0.418 | 15.8 | 0.760 | (7.1) | (0.342) |
| 1995 | 20.1 | 116.8 | 7.7 | 0.382 | 15.2 | 0.757 | (7.5) | (0.375) |
| 1996 | 18.2 | 122.7 | 6.3 | 0.344 | 14.8 | 0.814 | (8.5) | (0.470) |
| Total | 226.1 | 122.7 | 110.7 | 0.489 | 189.4 | 0.838 | (78.7) | (0.349) |

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 NPC rate of disadvantage (11.85%). Avoided cost benefits were taken from Table 4-13a. 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 service territory of the Nevada Power Company. Load shape impacts were calculated using the LBL Residential Energy and LBL Residential Hourly and Peak Demand Models. Financial impacts were calculated with the aid of a production-cost simulation program. 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. Extensive calibration to historic sales and peak demands preceded these forecasts and achieved good agreement with utility records.

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 rather even decrease in forecast loads throughout the year. The second, Level 8/12, was essentially the same standard but with a higher minimum efficiency for central air conditioners. This standard produced dramatic reduction 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, comparable to those produced by the Level 8 standard. The load shape impacts of the three standards are summarized in Table 5-1.

Table 5-1. Summary of Residential Class Load Shape Impacts

| Case | Growth (1987-1996) Energy (%/yr) | Growth (1987-1996) Demand (%/yr) | Impact by 1996 Load Factor (%) | Impact by 1996 Energy (GWh) | Impact by 1996 Demand (MW) | Impact by 1996 Demand (MW*) |
|---|---|---|---|---|---|---|
| Base | 2.99 | 2.61 | 42 | | | |
| Level 8 | 2.34 | 1.65 | 43 | 235.1 | 95.3 | 70.6 |
| Level 8/12 | 1.92 | 0.11 | 48 | 380.3 | 227.2 | 142.7 |
| Level 12/AC | 2.37 | 0.36 | 49 | 226.1 | 207.1 | 122.7 |

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

The financial impact calculations relied largely on the results of a production-cost model 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 costs of existing plants. In the long-run, capital costs of future plants figure into the calculation of avoided production costs. Both a reliability or capacity-related component and an energy-related component of the long-run capital investment decision were isolated. Once again, the production-cost model was first calibrated to the utility's own production-cost simulation results.

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 reducing lost revenues, as determined by the NPC forecast of future retail rates, by avoided marginal variable operating costs. For NPC, this cost is, in fact, a benefit since avoided marginal variable operating costs exceed projected retail rates.

The societal impact of load shape changes compares the avoided production costs against the additional cost of more efficient appliances. A lower discount rate was also used to compute the present value of savings.

Table 5-2 summarizes the financial impacts for the three policy cases. We find that ratepayers and society will differ in their preferences for the appliance standards. The greatest benefit from the ratepayer perspective results from the standards resulting in the highest class load factors. Level 8/12 and Level 12/AC. Level 8/12 yields the largest savings, but Level 12/AC has higher per unit values. Conversely, the greatest benefit from the societal perspective results from the Level 8 standard. We noted uncertainty in our estimation of the costs of more efficient appliances, which could increase the cost-effectiveness of the standards from the societal perspective.

Table 5-2. Summary of Financial Impacts

Ratepayer Perspective: Discount Rate = 15.07% (WACC)

| Standard | A<br>Avoided Cost<br>(M 1985$) | B<br>Rate Impact<br>(M 1985$) | A-B<br>Net Impact<br>(M 1985$) | <br><br>(1985$/kWh) |
|---|---|---|---|---|
| Level 8 | 62 | (15) | 77 | 0.325 |
| Level 8/12 | 107 | (25) | 132 | 0.349 |
| Level 12/AC | 74 | (17) | 91 | 0.401 |

Societal Perspective: Discount Rate = 11.85% (ROD)

| Standard | A<br>Avoided Cost<br>(M 1985$) | B<br>Equipment<br>(M 1985$) | A-B<br>Net Impact<br>(M 1985$) | <br><br>(1985$/kWh) |
|---|---|---|---|---|
| Level 8 | 98 | 61 | 37 | 0.156 |
| Level 8/12 | 166 | 210 | (44) | (0.115) |
| Level 12/AC | 111 | 189 | (78) | (0.349) |

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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# APPENDIX A

This discussion provides the technical documentation for our determination of the optimal deferral period resulting from the load shape impacts of the appliance standards. The interested reader is directed to Kahn (1986b) for additional details of the underlying logic behind the calculation.

The basic idea behind the deferral concept is that the deferral period represents, in an approximate fashion, the optimal supply system response to load shape changes. Three separate simulations are required:

1. Base case loads and resources (Case 1);
2. Base case loads with resources deferred by a given number of years (Case 2); and
3. Base case loads modified by policy case load shape impacts and with resources deferred as in Case 2 (Case 3).

Our definition of optimality obtains when the present value of variable operating costs under the Base Case (Case 1) are equal to those under the Modified Loads/Deferral Case (Case 3).

The deferral period was determined to be 2 years based on two Modified Load/Deferral Cases, incorporating the load shape impacts from the Level 8 and Level 8/12 standards. The results indicate that for both discount rates, costs are roughly the same using the load impacts from the Level 8 standard and are reasonably close using the load impacts from the Level 8/12 standard. Table A-1 contains our results. Table A-2 contains the underlying annual quantities from the Base and Modified Loads/Deferral Cases. More detailed study would involve further optimization.

Table A-1. Comparison of Base Case to Modified Loads/Deferral Cases

| | | WACC (15.07%) | ROD (11.85%) |
|---|---|---|---|
| Base Case / Level 8 Loads - 2 yr. Deferral | = | 1.024 | 1.021 |
| Base Case / Level 8/12 Loads - 2 yr. Deferral | = | 1.076 | 1.082 |

Table A-2. Variable Costs from Modified Load and Resource Deferrals

| Year | Base | | | Deferral-Level 8 | | | Deferral-Level 8/12 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Nominal | PV (WACC) | PV (ROD) | Nominal | PV (WACC) | PV (ROD) | Nominal | PV (WACC) | PV (ROD) |
| 1986 | 151.650 | 131.789 | 135.583 | 151.650 | 131.789 | 135.583 | 151.650 | 131.789 | 135.583 |
| 1987 | 168.440 | 127.210 | 134.040 | 165.968 | 125.343 | 132.664 | 167.095 | 126.194 | 133.565 |
| 1988 | 180.340 | 118.360 | 128.880 | 175.297 | 115.050 | 125.276 | 177.326 | 116.382 | 126.726 |
| 1989 | 212.165 | 121.011 | 135.569 | 203.175 | 115.884 | 129.816 | 206.994 | 118.062 | 132.256 |
| 1990 | 254.839 | 126.315 | 145.575 | 240.952 | 119.432 | 137.642 | 247.205 | 122.531 | 141.214 |
| 1991 | 291.070 | 125.379 | 148.656 | 279.436 | 117.362 | 139.139 | 280.074 | 120.642 | 143.040 |
| 1992 | 331.056 | 123.027 | 151.164 | 307.025 | 114.931 | 140.192 | 316.929 | 118.639 | 144.714 |
| 1993 | 408.227 | 132.802 | 150.653 | 351.899 | 114.478 | 143.658 | 365.400 | 118.870 | 149.170 |
| 1994 | 489.017 | 137.402 | 177.389 | 406.533 | 114.648 | 148.014 | 421.976 | 119.297 | 154.015 |
| 1995 | 541.982 | 133.157 | 176.858 | 475.016 | 116.704 | 155.006 | 495.540 | 121.749 | 161.706 |
| 1996 | 562.682 | 120.136 | 164.160 | 553.690 | 118.216 | 161.537 | 578.711 | 123.560 | 168.836 |
| 1997 | 634.274 | 117.688 | 165.442 | 622.641 | 115.529 | 162.407 | 652.740 | 121.114 | 170.258 |
| 1998 | 658.973 | 106.258 | 153.674 | 630.276 | 101.630 | 146.982 | 663.490 | 106.986 | 154.727 |
| 1999 | 729.826 | 102.270 | 152.165 | 699.332 | 97.997 | 145.807 | 737.667 | 103.369 | 153.800 |
| 2000 | 770.101 | 93.781 | 143.552 | 726.153 | 88.429 | 135.359 | 764.105 | 93.051 | 142.434 |
| 2001 | 847.251 | 89.664 | 141.201 | 797.205 | 84.368 | 132.860 | 839.765 | 88.871 | 139.951 |
| 2002 | 883.634 | 81.267 | 131.662 | 832.650 | 76.578 | 124.065 | 876.209 | 80.585 | 130.556 |
| 2003 | 970.589 | 77.582 | 129.310 | 912.911 | 72.964 | 121.613 | 961.639 | 76.869 | 128.104 |
| Trend (86-03) | 11.5 %/yr | | | 11.1 %/yr | | | 11.5 %/yr | | |
| 2004 | 1082.694 | 75.201 | 128.950 | 1014.580 | 70.470 | 120.838 | 1072.009 | 74.459 | 127.678 |
| 2005 | 1207.624 | 72.894 | 128.591 | 1127.572 | 68.062 | 120.067 | 1195.047 | 72.134 | 127.252 |
| 2006 | 1346.968 | 70.657 | 128.234 | 1253.148 | 65.736 | 119.302 | 1332.206 | 69.882 | 126.828 |
| 2007 | 1502.391 | 68.498 | 127.877 | 1392.709 | 63.488 | 118.541 | 1485.102 | 67.700 | 126.406 |
| 2008 | 1675.749 | 66.387 | 127.521 | 1547.813 | 61.318 | 117.785 | 1655.558 | 65.587 | 125.984 |
| 2009 | 1869.109 | 64.349 | 127.166 | 1720.190 | 59.222 | 117.034 | 1845.571 | 63.539 | 125.565 |
| 2010 | 2084.780 | 62.375 | 126.812 | 1911.765 | 57.198 | 116.288 | 2057.393 | 61.555 | 125.146 |
| 2011 | 2325.338 | 60.460 | 126.459 | 2124.675 | 55.243 | 115.546 | 2293.526 | 59.633 | 124.729 |
| 2012 | 2593.653 | 58.605 | 126.107 | 2361.296 | 53.355 | 114.810 | 2556.761 | 57.771 | 124.314 |
| 2013 | 2892.920 | 56.807 | 125.756 | 2624.270 | 51.531 | 114.078 | 2850.206 | 55.968 | 123.899 |
| 2014 | 3226.735 | 55.063 | 125.406 | 2916.530 | 49.770 | 113.350 | 3177.335 | 54.220 | 123.486 |
| 2015 | 3599.060 | 53.373 | 125.057 | 3241.339 | 48.069 | 112.628 | 3542.007 | 52.527 | 123.075 |
| 2016 | 4014.346 | 51.736 | 124.709 | 3602.321 | 46.426 | 111.909 | 3948.534 | 50.887 | 122.665 |
| 2017 | 4477.551 | 50.148 | 124.362 | 4003.506 | 44.839 | 111.196 | 4401.720 | 49.299 | 122.256 |
| 2018 | 4994.204 | 48.609 | 124.016 | 4449.369 | 43.306 | 110.487 | 4906.918 | 47.759 | 121.849 |
| 2019 | 5570.473 | 47.117 | 123.671 | 4944.888 | 41.826 | 109.782 | 5470.100 | 46.268 | 121.443 |
| 2020 | 6213.235 | 45.671 | 123.327 | 5495.592 | 40.396 | 109.082 | 6097.920 | 44.824 | 121.038 |
| 2021 | 6930.165 | 44.270 | 122.984 | 6107.626 | 39.015 | 108.387 | 6797.797 | 43.424 | 120.635 |
| 2022 | 7729.818 | 42.911 | 122.642 | 6787.822 | 37.682 | 107.696 | 7578.000 | 42.068 | 120.233 |
| Total | | 3161.123 | 5071.771 | | 2938.278 | 4680.426 | | 3088.057 | 4966.135 |

Sources: LBL Telplan Run, NPCBASE, February 27, 1986;
LBL Telplan Run, NPCXDEFR12, March 25, 1986;
LBL Telplan Run, NPCXDEFR8, March 25, 1986.

# APPENDIX B

The following pages contain supporting avoided production cost tables for the calculation of societal impacts. The values in these tables have been discounted to 1985 present values using the NPC rate of disadvantage, 11.85%. The tables retain the numbering of their counterparts in the text.

Table 4-11a. Avoided Production Costs - Level 8 Appliance Standards, All End-Uses
Nevada Power Company

| Year | Energy Savings | | | | Capacity Savings | | | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total (GWh) | Increment (GWh) | Total (M$) | ($/kWh) | Total* (MW) | Increment (MW) | Total (M$) | ($/kWh) | Total (M$) | ($/kWh) |
| 1987 | 24.6 | 24.6 | 10.0 | 0.406 | 8.3 | 8.3 | 1.7 | 0.071 | 11.7 | 0.477 |
| 1988 | 49.5 | 24.9 | 9.7 | 0.389 | 16.4 | 8.1 | 1.9 | 0.078 | 11.6 | 0.467 |
| 1989 | 74.6 | 25.1 | 9.4 | 0.373 | 24.6 | 8.2 | 2.2 | 0.087 | 11.6 | 0.460 |
| 1990 | 100.2 | 25.6 | 9.1 | 0.356 | 32.9 | 8.3 | 2.4 | 0.095 | 11.5 | 0.450 |
| 1991 | 126.3 | 26.1 | 8.7 | 0.333 | 40.8 | 7.9 | 2.5 | 0.096 | 11.2 | 0.429 |
| 1992 | 148.4 | 22.1 | 6.8 | 0.310 | 47.3 | 6.5 | 2.2 | 0.100 | 9.1 | 0.410 |
| 1993 | 170.0 | 21.6 | 6.2 | 0.286 | 53.6 | 6.3 | 2.3 | 0.106 | 8.5 | 0.392 |
| 1994 | 192.3 | 22.3 | 6.0 | 0.271 | 59.7 | 6.1 | 2.1 | 0.094 | 8.1 | 0.385 |
| 1995 | 213.8 | 21.5 | 5.5 | 0.257 | 65.5 | 5.8 | 1.9 | 0.088 | 7.4 | 0.345 |
| 1996 | 235.1 | 21.3 | 5.2 | 0.243 | 70.6 | 5.1 | 1.6 | 0.074 | 6.8 | 0.317 |
| Total | | 235.1 | 76.6 | 0.326 | | | 20.9 | 0.089 | 97.5 | 0.415 |

* Average change over 500 highest hourly loads.

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC rate of disadvantage (11.85%). See tables 4-8 and 4-14 for the components of these values.

Table 4-12a. Avoided Production Costs - Level 12 Cooling End-Uses, Level 8 All Others
Nevada Power Company

| Year | Energy Savings | | | | Capacity Savings | | | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total (GWh) | Increment (GWh) | Total (M$) | ($/kWh) | Total* (MW) | Increment (MW) | Total (M$) | ($/kWh) | Total (M$) | ($/kWh) |
| 1987 | 40.3 | 40.3 | 16.6 | 0.411 | 10.4 | 10.4 | 4.1 | 0.101 | 20.7 | 0.513 |
| 1988 | 80.3 | 40.0 | 15.7 | 0.393 | 38.0 | 18.6 | 4.5 | 0.111 | 20.2 | 0.505 |
| 1989 | 121.4 | 41.1 | 15.5 | 0.376 | 56.5 | 18.5 | 4.9 | 0.120 | 20.4 | 0.496 |
| 1990 | 163.7 | 42.3 | 15.1 | 0.357 | 74.1 | 17.6 | 5.2 | 0.122 | 20.2 | 0.479 |
| 1991 | 205.4 | 41.7 | 13.9 | 0.334 | 90.0 | 15.9 | 5.1 | 0.121 | 19.0 | 0.455 |
| 1992 | 240.8 | 35.4 | 11.0 | 0.310 | 102.5 | 12.5 | 4.3 | 0.121 | 15.2 | 0.431 |
| 1993 | 276.1 | 35.3 | 10.1 | 0.286 | 114.1 | 11.6 | 4.2 | 0.119 | 14.3 | 0.405 |
| 1994 | 312.0 | 35.9 | 9.7 | 0.271 | 125.0 | 10.9 | 3.8 | 0.105 | 13.5 | 0.375 |
| 1995 | 346.9 | 34.9 | 9.0 | 0.257 | 134.7 | 9.7 | 3.2 | 0.091 | 12.1 | 0.347 |
| 1996 | 380.3 | 33.4 | 8.1 | 0.243 | 142.7 | 8.0 | 2.5 | 0.074 | 10.6 | 0.317 |
| Total | | 380.3 | 124.6 | 0.328 | | | 41.6 | 0.109 | 166.2 | 0.437 |

* Average change over 500 highest hourly loads.

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC rate of disadvantage (11.85%). See tables 4-8 and 4-14 for the components of these values.

Table 4-13a. Avoided Production Costs - Level 12 Standards, Cooling End-Uses Only
Nevada Power Company

| Year | Energy Savings: Total (GWh) | Increment (GWh) | Total (M$) | ($/kWh) | Capacity Savings: Total* (MW) | Increment (MW) | Total (M$) | ($/kWh) | Total: Total (M$) | ($/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1987 | 24.6 | 24.6 | 10.3 | 0.420 | 17.5 | 17.5 | 3.7 | 0.150 | 14.0 | 0.570 |
| 1988 | 49.4 | 24.8 | 9.9 | 0.400 | 34.2 | 16.7 | 4.0 | 0.161 | 13.9 | 0.561 |
| 1989 | 74.4 | 25.0 | 9.5 | 0.381 | 50.7 | 16.5 | 4.4 | 0.176 | 13.9 | 0.557 |
| 1990 | 100.0 | 25.6 | 9.2 | 0.359 | 66.2 | 15.5 | 4.5 | 0.178 | 13.7 | 0.537 |
| 1991 | 125.1 | 25.1 | 8.4 | 0.335 | 79.9 | 13.7 | 4.4 | 0.174 | 12.8 | 0.509 |
| 1992 | 146.4 | 21.3 | 6.6 | 0.311 | 90.5 | 10.6 | 3.6 | 0.170 | 10.2 | 0.481 |
| 1993 | 167.0 | 20.6 | 5.9 | 0.286 | 100.2 | 9.7 | 3.5 | 0.171 | 9.4 | 0.457 |
| 1994 | 187.8 | 20.8 | 5.6 | 0.271 | 109.1 | 8.9 | 3.1 | 0.147 | 8.7 | 0.418 |
| 1995 | 207.9 | 20.1 | 5.2 | 0.257 | 116.8 | 7.7 | 2.5 | 0.125 | 7.7 | 0.382 |
| 1996 | 226.1 | 18.2 | 4.4 | 0.243 | 122.7 | 5.9 | 1.8 | 0.100 | 6.3 | 0.344 |
| Total | | 226.1 | 75.1 | 0.332 | | | 35.5 | 0.157 | 110.7 | 0.489 |

* Average change over 500 highest hourly loads.

All dollar amounts are the 1985 present value of saving the increment of energy for 12 years. The discount rate is the NPC rate of disadvantage (11.85%). See tables 4-8 and 4-14 for the components of these values.

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