LONG TERM ELECTRIC PEAK DEMAND

AND CAPACITY RESOURCE FORECAST

FOR TEXAS

1990

VOLUME I

SUMMARY OF RESULTS AND RECOMMENDATIONS

MARCH 1991

THE PUBLIC UTILITY COMMISSION OF TEXAS

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The current staff wishes to recognize the contribution made by Dr. Jay Zarnikau, former Director of Electric Utility Regulation, to this and all prior forecast reports.

Partial funding for some of the research described in this three-volume report was provided from Oil Overcharge settlement funds as allocated in Art. 5, Section 125, Senate Bill 222, 71st Legislature of the State of Texas.

ABSTRACT

There is more than adequate electrical generating capacity in the near term in Texas. This offers luxuries to Texans (high reliability), but also imposes costs (large power plant investments reflected in rate increases in certain electric service areas). Despite these near-term capacity surpluses, a number of resource planning issues deserve prompt attention if Texas is to remain a low-cost provider of reliable electricity. The resource planning issues identified in this report include:

1. Defining the appropriate degree of operating and planning coordination among the utilities in Texas
2. Determining the role of cogenerated power
3. Determining how to better use the transmission system
4. Alleviating potential transmission bottlenecks in some areas
5. Determining the role of conservation programs which increase the efficiency of electrical energy use
6. Estimating the importance of rate design as a resource planning tool

The **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas 1990** is designed to provide information and recommendations to policy makers and others interested in the present and future status of the Texas electric power industry. Volume I of this three-volume report provides staff-recommended electricity demand projections for thirteen of the state's largest utilities and a capacity resource plan for Texas. Fuel markets, cogeneration activity, demand-side management program impacts, environmental issues, and strategic rate design are highlighted.

Volume II summarizes the electricity demand forecasts, energy efficiency plans, and capacity resource plans developed by generating electric utilities and filed at the Commission in December 1989 (or later amended). The third volume provides a technical description of the Commission staff's econometric electricity demand forecasting system used to develop the load forecast contained in Volume I.

The Commission is required to submit a statewide electrical energy plan to the governor every two years. The 1984 and 1986 plans focused on the development of load forecasting methodologies, data, and models, and a review of the capacity expansion plans dominated by utility-owned generating units. The central theme of the 1988 plan

(in light of the statewide recession) was the identification of the means to achieve greater efficiency in the use of the state's electrical resources.

The current report recognizes the end of the late 1980s economic recession in Texas, yet continues to emphasize efficiency improvements as the key to reliable and low-cost electrical services, environmental integrity, and increased economic growth. Within this framework, substantial emphasis is placed on alternative power sources (particularly purchases from qualifying facilities) and energy efficiency to reduce the rate of growth of peak demand. The information contained here emphasizes the importance of planning generally and the techniques applied specifically by the Commission staff to forecasting and planning.

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CHAPTER ONE

SUMMARY AND INTRODUCTION

Summary of Results

Texas is predicted to have sufficient electrical energy resources to meet its growing energy needs over the next ten years (1990 to 2000).[1] This is indicated whether one accepts the load forecasts and capacity resource plans prepared by the utilities in Texas (summarized in Volume II of this report) or, instead, the independent load projections and recommended resource plans developed by the Electric Division staff of the Public Utility Commission of Texas (Commission staff), reported in this volume. While the resource plans currently being pursued by the Texas utilities are likely to result in a reliable power system, the Commission staff recognizes a number of additional actions that could be taken to improve system efficiency and electrical energy costs, and to maintain or improve system reliability.

Words of caution regarding the use of this report

It should be noted that the projections contained herein are intended as a planning tool and do not reflect an official policy position or a prediction by the Commission. The projections indicate what future demand and electricity sales are likely to be assuming a continuation of recent trends in the many factors which influence electricity use.

This report represents a 1990 work product of the Commission staff. As an aid to understanding the relative positions of the Commission staff and the major generating electric utilities, comparisons are made throughout this report with the data filed by

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1 The "10-year" forecast and resource plan discussed throughout this report actually covers the period 1990 to 2000 (or 11 years, inclusive). The eleventh year is included to facilitate comparisons with other reports and projections, many of which refer to the year 2000.

regulated utilities in December 1989.[2] These 1989 forecasts are the most recent utility data available.[3]

The Commission staff remains committed to providing the most accurate and current information that its staffing constraints will permit. The Commission staff maintains that neither this report nor any other forecasting or planning-related documents preclude the use of the most up-to-date information available when called for in a proceeding before the Commission.

The Demand for Electricity in Texas

Based on results derived from the staff Econometric Electricity Demand Forecasting System, statewide peak demand is expected to grow at an annual rate of 2.50 percent over the next ten years, reaching 60,883 MW by the year 2000. This compares to the utility-projected 2.46 percent annual growth rate, resulting in a 60,594 MW peak demand in the year 2000. These are both base-case projections presented after all adjustments for conservation, load management, promotional efforts, and exogenous factors are considered.

These projected growth rates in demand contrast sharply with the rapid increases in statewide peak demand experienced historically in Texas. From 1950 to 1970, peak demand in Texas increased at a high and relatively stable 10 percent annual rate. From 1975 to 1985, a period of rapid increases in energy prices, annual peak demand growth in Texas slowed to a rate of approximately 5 percent. In recent years, peak demand has declined in some areas of the state, with little change statewide. However, due to improvements in the Texas economy, the Commission staff anticipates growth in all electric service areas.

The load projections developed by the Commission staff and the utilities assume a gradual recovery from the recession experienced in Texas during the last few years. Industrial diversification efforts within the state, a rebounding energy industry, and population growth rates in excess of national rates are expected to contribute to stronger electricity demand. While the state's economic performance is expected to improve, it is unlikely that Texas will again, in the foreseeable future, achieve the economic growth

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2 On February 15, 1990, utilities were required to update their December filing with actual 1989 figures. Commission staff identifies and corrects problems with historic data on an ongoing basis.

3 In future forecast reports, staff will attempt to compare the staff's forecasts with the utilities' current-year forecasts.

experienced in the 1970s and early 1980s. It is worth mentioning that both the Commission staff and the utilities are projecting slower annual growth in electricity demand than was projected two years ago.

Also expected to contribute to electricity demand growth are higher saturations of electrical equipment in the residential sector, particularly electric heating equipment, air conditioning, and electric cooking appliances. The impact of higher saturations of electricity consuming equipment will be somewhat offset by greater equipment energy efficiencies attributable to technological progress, utility-sponsored conservation programs, and federal appliance standards (the National Appliance Energy Conservation Act of 1987).

In the later years of the forecast horizon, electricity prices are expected to become more favorable relative to natural gas costs. Nominal electricity prices are expected to increase at modest rates over the next ten years. A decline is expected in electric rates in real dollar terms for most regions of the state, due mainly to lower rates of capital investment and slower growth in fuel prices, particularly in the price of natural gas.

While statewide economic growth and favorable electric rates are expected to contribute to growth in electricity demand, a number of factors will serve to constrain that growth. As a reaction to likely rate increases by utilities with investments in nuclear projects, a number of large industrial energy consumers along the Gulf Coast (served by HL&P, GSU, CPL, and TNP) are pursuing self-generation or cogeneration projects to reduce their dependence on utility-supplied power.

The Commission staff has updated its independent peak demand forecasts for thirteen of the state's largest utilities. The following list provides the acronym and membership status in electric reliability councils. These include the Electric Reliability Council of Texas (ERCOT), the Western Systems Coordinating Council (WSCC), and Southwest Power Pool (SPP).

Company	Acronym	Council
Texas Utilities Electric Company	TU Electric	ERCOT
Houston Lighting and Power Company	HL&P	ERCOT
Gulf States Utilities Company	GSU	SPP
Central Power and Light Company	CPL	ERCOT
City Public Service Board of San Antonio	CPS	ERCOT
Southwestern Public Service Company	SPS	SPP
Southwestern Electric Power Company	SWEPCO	SPP
Lower Colorado River Authority	LCRA	ERCOT
City of Austin Electric Utility	COA	ERCOT
West Texas Utilities Company	WTU	ERCOT
El Paso Electric Company	EPE	WSCC
Texas-New Mexico Power Company	TNP	ERCOT
Brazos Electric Power Cooperative, Inc.	BEPC	ERCOT

In order to compare the peak demand projections contained in the 1988 report and this report, the forecast year 1997 was selected. Except for HL&P, GSU, CPL, and BEPC, all major utilities reduced their peak demand projections for 1997 between the 1987 and 1989 filings. Staff also reduced its 1997 peak demand projections for all major electric utilities with the exception of HL&P, GSU, CPL, EPE, and BEPC. However, the utilities reduced their 1997 peak demand forecast for Texas by 1 percent while reduction in the staff's forecast was 4 percent. A utility-specific forecast revision by the staff is provided in Chapter 3.

TU Electric. The Commission staff's Econometric Electricity Demand Forecasting system projects a peak demand of 21,945 MW for the TU Electric system in the year 2000. Peak load and energy sales are forecast to increase at annual rates of 2.38 percent and 2.55 percent, respectively, from 1989 to 2000. Since the release of the 1988 forecast report, both the Company and the staff have lowered their demand forecasts for the TU Electric system. The staff projections are largely in agreement with the Company's filing.

HL&P. Since release of the 1988 forecast report, both the company and the staff have lowered their demand forecasts for the HL&P system. Under the staff projections, the state's second largest electric utility is expected to experience a 2.52 percent annual increase in peak load through the year 2000, with electricity sales growing at a 2.19 percent rate. HL&P's forecast also shows a 2.05 percent annual increase in peak demand over the forecast period. The difference between the staff and the utility projections may largely be traced to projections of energy sales to the residential class. While HL&P projects an annual increase of almost 1 percent in residential sector energy consumption in its service area, the Commission staff is forecasting an annual growth rate of 2.78 percent throughout the 10-year forecast horizon. Both the Company and Commission staff projections indicate that completion of the Robertson generating units (TNP One) by Texas-New Mexico Power Company (HL&P's largest wholesale customer) and increased self-generation activity among local industrial energy consumers will reduce or constrain wholesale and industrial sector sales and demand. The Commission staff's peak demand forecast for HL&P in the year 2000 is 13,754 MW.

GSU. GSU has generally experienced a declining peak demand since 1980. Staff projections indicate slow but consistent growth in peak load and sales over the next ten years at an annual rate of around 1.12 percent to a Texas peak of 2,472 MW in the year 2000. Demand growth is expected to be stronger in the Company's non-Texas service area. GSU anticipates a year 2000 peak demand of only 24 MW more than the Commission staff projection. Recent decreases in electricity demand may be traced to a depressed service area economy and volatility in the Company's rates. The current staff projection in annual demand growth is higher than the peak demand presented in the 1988 report. Commission staff projects a 5,616 MW system peak demand for GSU.

CPL. While electricity sales to the residential and commercial customer classes are projected to remain strong, many of CPL's large industrial customers have turned, or are planning to turn, to self-generation and reduced reliance on the utility. Self-generation is a response to anticipated higher rates attributable to the Company's involvement in the South Texas Nuclear Project (STNP) and presently depressed natural gas prices. Staff projects an annual growth rate of 2.71 percent in peak demand reaching 3,968 MW in the year 2000. The projections prepared by CPL and the Commission staff are only 28 MW apart from each other in the year 2000.

CPS. A strong 3.3 percent annual growth rate in peak load is forecast for the CPS system. Having already collected a large percentage of the construction costs associated with its share of the STNP from its ratepayers, CPS should be able to constrain future rate increases. Population growth and favorable rates will contribute to relatively high levels of electricity consumption growth, particularly in the residential and commercial sectors. Staff projects a peak demand of 3,854 for CPS in the year 2000, lower than CPS's projected 4,110 for that year.

SPS. Serving the Texas Panhandle region, SPS is forecast to have an annual growth rate in peak demand of around 1 percent over the next ten years. The staff projections are slightly lower than the forecasts prepared by the utility. Both the Commission staff and Company have lowered their forecasts from what appeared in the 1988 forecast report. Staff projects a 3,367 MW demand for SPS in the year 2000.

SWEPCO. Serving northeast Texas and portions of Louisiana and Arkansas, SWEPCO is projected to have an annual peak demand growth of around 3.26 percent through the year 2000. Peak demand will approach 4,002 MW by the year 2000 on a total-system basis, and 2,092 MW on a Texas-only basis. Demand growth is expected to be stronger in the Texas than in the non-Texas service area. This projection is a reduction from the staff's 1988 demand forecast.

LCRA. Operating in Central Texas, LCRA's peak demand and sales are forecast to increase at annual rates of 3.3 percent and 3.5 percent, respectively, over the forecast horizon. Among major generating utilities in Texas, LCRA is expected to experience the third highest rate of demand growth. This updated load forecast is lower than the Commission staff's 1988 projections due to continued economic stagnation in Central Texas and a less optimistic short-term economic outlook for the service area. The demand forecast for the year 2000 is 2,242 MW.

COA. The summer peak load for the City of Austin is expected to rise from 1,408 MW in 1989 to about 1,918 MW in the year 2000. Projected annual growth in peak demand and total sales are 2.85 percent and 2.65 percent, respectively.

WTU. The Commission staff projects a 2.32 percent annual growth rate for WTU peak demand over the next ten years. While the Company forecasts lower growth in the near term, the WTU and Commission staff results are very similar for the mid 1990s. Commission staff projects a system peak demand of 1,459 MW for WTU in the year 2000.

EPE. Historically, the staff projections have been considerably more pessimistic than the forecasts prepared by EPE for that utility's service area. The current Commission staff forecast show slightly higher rates of growth than the Company forecast. However, the differences between EPE and staff projections are smaller than they have been in the past. A 2.73 percent annual growth rate in peak demand is projected by the staff, resulting in a 1,241 MW system demand for the Company.

TNP. The staff projection of Texas system sales and peak demand for TNP are 6,148 GWH and 1,220 MW, respectively, for the year 2000. The forecast annual growth rates for energy and peak demand are 2.18 percent and 2.12 percent, respectively. The Commission staff's forecast is slightly higher than the Company's peak demand forecast by the year 2000.

BEPC. Included in this report is an independent demand forecast for Brazos Electric Power Cooperative, Inc. The Commission staff projects that BEPC will have the highest growth rate in electricity demand over the next ten years among all major Texas electric utilities. According to this projection, peak demand will increase at an annual rate of 4.16 percent, reaching 1,270 MW in the year 2000. The projections prepared by the Commission staff and BEPC are very close throughout the forecast period.

In general, the Commission staff has achieved a higher degree of accuracy in projecting future electricity demand than the Texas utilities over the past few years. However, a considerable degree of uncertainty in both the staff's and the industry's 10-year load projections must be acknowledged. Based on statistical results attained by the staff, **plus or minus 5 percent** may be applied to the staff's projections to recognize this uncertainty.

At the present time, a key uncertainty in demand growth involves future self-generation activity. Even without the availability of firm capacity payments to cogenerators, many firms involved in the chemical, petrochemical, and petroleum refining industries have found it more economical to self-generate with cogeneration technologies than to continue to purchase from their utility supplier. The HL&P, GSU, CPL, and TNP service areas will continue to be affected by self-generation. At industrial retail electricity rates between 5 and 6 cents per KWH, the loss of industrial load to self-generation activity is highly uncertain but could potentially affect a very large portion of a utility's large-industrial load.

Other major factors which will influence electricity sales are natural gas price and availability, and the impact of the 1990 amendments to the Clean Air Act. Both natural gas price increases and the cost of compliance with the Clean Air Act will increase the costs of electricity production, which usually results in higher rates and lower demand.

Electrical Energy Resources

Traditionally, the construction of electrical generating capacity was the most economical means of meeting growth in demand. Electric utilities now rely on a variety of supply-side and demand-side resources to meet the state's growing electrical energy needs. These include:

1. Construction of additional generating capacity
2. Non-utility generation (cogeneration and small power production)
3. Demand-side management (including conservation programs, load management programs, and strategic rate design)
4. Purchased power from other utilities
5. Efficiency improvements in generation, transmission, and distribution systems

Given the Commission staff demand forecasts and target reserve margins, potential resources were compared on the basis of cost and reliability. The analysis indicates that there may be opportunities for delaying planned capacity additions through greater purchased power transactions and greater reliance upon both demand-side management and firm capacity available from cogenerators, relative to the reliance upon those resources presently planned by the utilities in the state.

Target reserve margins. The Commission staff has reviewed and generally supports the target reserve margins that the state's major generating utilities have established for planning purposes. These reserve margins reflect the utility's capacity needs, in excess of expected peak demand, required to maintain reliability. The Electric Reliability Council of Texas requires its member utilities to maintain a minimum 15 percent target reserve margin. Some ERCOT utilities are using higher targets which may be justified due to larger base load capacity units, increased dependence on non-utility generation, and uncertain performance of nuclear units during their first few years of operation. The Western Systems Coordinating Council and the Southwest Power Pool, two adjoining reliability councils which also serve in parts of Texas, have established different methodologies for calculating reliability standards for their member utilities.

Commission staff analysis indicates that target reserve margins adopted by HL&P for planning purposes could be reduced from 1991 through 2000 without impairing reliability. Commission staff recommends reducing the 20 percent target established by the Company to 18 percent. If demand increases more rapidly than currently expected during this period, additional capacity could be secured from cogenerators.

Cogeneration. Industrial cogeneration presently supplies, and will continue to supply, a significant part of the total electric energy needs in Texas. Cogeneration has developed very rapidly during the past few years. However, its growth now seems to be slowing and its continued development will depend on the economic vitality of the chemical, petrochemical, and petroleum refining industries in Texas, the relative prices of electricity and natural gas, the levels of standby charges, and, most importantly, the need for additional electricity generating capacity in the state. The need for additional generating capacity by the utility industry affects capacity payments made for the available cogenerating capability.

Of the 7,117 MW of cogeneration capacity presently operational in Texas, approximately 45 percent is currently under contract to provide firm capacity to the state's utilities. The remaining cogeneration capacity provides non-firm or firm energy or satisfies on-site energy requirements. An additional 73 MW of cogeneration was under construction in the state in 1989. Upon completion of the remaining nuclear unit (Comanche Peak Steam Electric Station CPSES, unit 2) and considering the capacity level already added by South Texas Nuclear Project (STNP Units 1 and 2), the involved utilities plan to reduce--as a percentage of peak demand--their reliance on cogeneration to provide firm capacity through the forecast period.

Demand-side management. During the second half of the 1980s, many utilities reduced their conservation program efforts and initiated aggressive promotional programs to encourage electrical energy use. Staff has maintained that promotional strategies are not in the long-term interest of the customers and may conflict with other policy objectives. Recent Commission decisions have probably influenced the decision of several utilities to revise their Energy Efficiency Plans and to refocus on encouraging energy efficiency and customers' desire for lower electricity bills.

The discussion of demand-side management and other adjustments to the "raw" econometric forecasts are presented in Chapter 5. Total adjustments to peak demand are the sum of exogenous factors (primarily the efficiency gains from federal appliance legislation) and demand-side management (including conservation and load management programs and interruptible loads). The statewide peak demand is projected to be 5.5 percent lower in the year 2000 than it would be without the Commission staff's demand-side management adjustments to peak demand. This is equivalent to a 3,601 MW reduction in projected peak demand by the year 2000. (In addition, exogenous factors will reduce peak demand by 542 MW in the year 2000.)

Deferral of utility-owned capacity. Based on the analysis of resource options available to the electric power industry, some opportunity to defer utility-planned capacity additions is apparent. The known capacity additions recommended for deferral beyond the year 2000 include the 645 MW (lignite-fueled) Malakoff Unit 2 (HL&P), and the 498 MW (coal-fueled) J. K. Spruce Unit 2 (CPS). In addition, the Commission staff is recommending deferral of unnamed capacity beyond the year 2000: 1,249 MW of coal- and lignite-fueled units (various utilities) and 582 MW of natural gas-fueled units (various utilities). In total, Commission staff recommends deferral of 2,974 MW of capacity beyond the year 2000 as compared to the utilities' proposed December, 1989 resource plans.

Additionally, the Commission staff proposes delays in the commercial operating dates of the TU Electric's Twin Oak Units 1 and 2 and Forest Grove Unit 1. Staff also recommends delays in Malakoff Unit 1, J.K. Spruce Unit 1, and several natural gas units over the forecast period.

HL&P's Malakoff Unit 1, presently scheduled for completion in December 1996 (Company's December, 1989 filing), could be deferred beyond that date as a result of the lower target reserve margin used in the staff analysis, more reliance on available cogenerated power, and the acceleration of conservation program implementation. HL&P has deferred construction of this unit a number of times in the past and has recently finalized a new resource plan with a two-year deferral in the commercial operation date of Malakoff Unit 1. Currently, HL&P plans to defer the Malakoff Units even further to the year 2000 and 2002.

The staff demand projections for COA is lower than the demand forecast prepared by the utilities, thus utility planned capacity addition for 1999 could be deferred.

For the purposes of this report, the Commission staff does not recommend any changes to the utility-proposed on-line dates for Comanche Peak (CPSES) Unit 2 (TU Electric), the combustion turbines completed by TU Electric in 1990, and TNP One Units 1 and 2 (TNP). However, the Commission staff will continue to monitor the construction costs associated with these projects. A change in the status of these projects may be warranted if present circumstances change.

Completion of the CPSES and other base load capacity additions will have a considerable impact on natural gas markets. In 1975, about 90 percent of the electricity generated by utilities in Texas was fueled with natural gas. In 1989, this percentage declined to 38 percent. The 4,800 MW of nuclear capacity in Texas from STNP Units 1 and 2 and CPSES Units 1 and 2 is expected to displace 250 to 330 billion cubic feet of natural gas fuel use per year. In the near term this reduction in demand is likely to contribute to continued surplus deliverability and price stability. In the long-term, however, persistently lower prices may limit exploration and drilling activity, thereby reducing the ratio of reserves to production and increasing the risk of price escalation. However, such future price escalation would be constrained by the prices of competing energy sources.

Electric Rates in Texas

For most regions of Texas, electric rates are below national averages and are expected to remain below national averages for the foreseeable future. Due to rising fuel prices, general inflation, and capacity requirements, electric rates in Texas doubled between 1976 and 1985 in nominal terms. However, electricity prices have stabilized and, generally, decreased since 1985.

Considerable variation may be seen in the rates charged by the electric utilities in Texas. SPS, CPS, and SWEPCO presently charge the lowest residential rates at the 1,000 KWH per month consumption level, while EPE, WTU, and HL&P have the highest. LCRA, a utility which primarily provides wholesale power to cooperatives and municipally-owned utilities in the Central Texas region, charges among the lowest rates in the state.

For most areas of the state, future electricity price increases are expected to be at rates below the anticipated rate of general inflation. Utility construction programs are winding down, and, consequently, large new capacity additions to utility rate bases will become less frequent. Successful utility diversification efforts and continued low fuel prices will constrain utility fuel costs, at least in the near term.

Potential Problems Ahead and Key Uncertainties

While the outlook for the Texas electric power industry is generally favorable, a number of planning-related issues deserve prompt attention from the utility industry and regulators.

As noted in the final report from the Commission's Bulk Power Transmission Study and the near-final version of the Optimal State Electricity Supply in Texas study, transmission constraints in some areas of the state may prevent the economical transmission of power. Without expansion of the transmission system, future power transfers could create reliability problems. Of particular concern is the status of the transmission network in the City of Austin and along the Houston-to-Dallas corridor where several large projects have been delayed.

Near-term price increases by some utilities in Texas, particularly those involved in nuclear power projects, are of concern. Increased industrial rates, coupled with continued low natural gas prices, may result in loss of industrial customers with the capability to self-generate. This is a particular concern for utilities along the Gulf Coast, where a concentration of industries capable of self-generation exists.

Environmental, public health, and energy security concerns may have a significant impact on the provision of electric power in Texas. Nuclear waste disposal, acid rain concerns, and global warming problems have yet to be fully addressed by the federal government. Real or imagined health concerns regarding high voltage transmission lines and nuclear power could affect system reliability. Efforts to reduce the nation's dependence upon foreign crude oil may result in higher electric rates and increased interest in conservation.

Movement toward a more competitive market for power will bring both new opportunities and new problems. Greater competition is entering the state's market for power in many forms. For example, cooperatives and municipal distribution utilities are showing increasing interest in shopping around for power from various utilities and cogenerators to secure power on the most attractive terms. Ultimate power consumers (the Capitol complex in Austin, for example) are also attempting to secure power from alternative sources that can supply electricity less expensively than their traditional providers. Utilities burdened with high fixed costs (due to recently completed power plants) may be at a competitive disadvantage and find it difficult to recover their allowed revenue requirement under present pricing practices.

Complacency with respect to utility planning during this phase of excess generating capacity and high reliability may jeopardize an economical and reliable electric power system for the future.

Objectives of this Report

The Texas Public Utility Regulatory Act mandates the development by the Commission of a biennial long-term statewide electrical energy forecast. This is the fourth such report which the Commission staff has prepared and recommended for adoption.

As in the 1984, 1986, and 1988 reports, this **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas 1990** report is designed to satisfy a number of objectives and summarize research findings in a number of related areas. The materials presented in this report include:

1. Commission staff-prepared peak demand and sales forecasts for most of the larger generating electric utilities in Texas
2. Detailed resource planning recommendations designed to insure that the future electrical energy needs of the state are met in a reliable and economical manner
3. Staff analyses of fuel markets, cogeneration activity, and demand-side management impact and savings
4. A review of current utility-developed load forecasts and the capacity expansion plans presently being pursued by the state's utilities
5. Independent staff projections of future electricity prices
6. A summary of results from a variety of special projects

Together, this information is designed to provide a comprehensive and accurate outlook for the state's electric power industry and insight into key planning issues.

Summary of Methodology

The staff is presently involved in a number of complementary projects designed to promote an enhanced understanding of the state's electric power industry, to assist in identifying future potential problems and opportunities, and to provide policy makers with information and recommendations. This report provides a synthesis of the findings from these research projects and routine activities.

As required by the Public Utility Regulatory Act, most of the state's generating utilities filed Load and Capacity Resource Forecasts with the Commission in December 1989. Utility Energy Efficiency Plans, required by the Commission's Substantive Rules, were also filed at the Commission by the regulated Texas utilities in December 1989. Together, these filings document the industry's current projections and resource strategies. The utility filings, summarized in Volume II of this report, provide the basis for much of the staff's independent analysis.

To forecast the future demand for electricity, two forecasting systems are used. The Econometric Electricity Demand Forecasting System remains the primary forecasting tool and is utilized to obtain the projections presented in this volume. The End-Use Modeling System provides a validity check on the results obtained through the econometric models, contributes more detailed projections of energy consumption at the appliance or equipment end-use level, and is used to estimate the impact of the federal appliance standards. Both econometric and end-use forecasting systems have been significantly enhanced and refined since the release of the 1988 report.

On-going programs designed to monitor power plant operations, generation and transmission construction projects, and cogeneration activity form the basis for much of the analysis of supply-side resource options presented in this volume.

Finally, this document relies on the results of several staff-sponsored studies. These studies are discussed in Chapter 7.

Organization of Report

The first volume of this three-volume report presents the results from the Commission staff's independent analysis of future electrical load and capacity resources in Texas. Volume II describes the forecasts and capacity expansion plans developed by the state's utilities. Volume III provides detailed technical documentation on the models developed by the staff to forecast demand growth.

Chapter 2 of Volume I discusses various determinants of electricity demand and resources in Texas. Included in this chapter is an outlook for the state's economy, a discussion of trends in electricity consumption, a presentation of historical information on electricity prices in Texas, and an outlook for fuel markets.

Economic activity is a key determinant of electricity demand growth and future resource requirements. While the state's recent severe economic recession is now almost over, some sectors of the economy and regions of the state have not yet completely rebounded. Among regional forecasters, there appears to be some disagreement over the future of the state's economy. Detailed information on the basic economic and demographic assumptions underlying the staff demand projections is provided in Volume III of this report.

With completion of new nuclear, lignite, and coal-fueled power plant projects, the Texas electric power industry's diminishing dependence upon natural gas is discussed. An outlook for fuels markets is presented in the final section of Chapter 2.

Chapter 3 reports the staff's independent electricity demand projections for the thirteen largest generating electric utilities in Texas. In general, these projections are consistent with the forecasts prepared by the state's utilities. In any long-term forecasting effort, there is considerable uncertainty; thus the final section of Chapter 3 reviews the accuracy of the utilities' past demand forecasting efforts.

Chapter 4 highlights two special topics: environmental issues and pricing strategies. The passage of the 1990 amendment to the Clean Air Act will have a significant effect on electric utilities' production costs and will ultimately result in electricity price increases and impacts on electric demand. As utility resource planners have recently shown interest in using rate design as a planning tool, Chapter 4 discusses both the rate design resource option and a summary of the pricing options under consideration in Texas.

Chapter 5 describes the demand-side resources which will influence electricity consumption, including the federal appliance standards and conservation and load management programs. Included are descriptions of the utilities' energy efficiency goals and demand-side management programs now in place.

Chapter 6 considers the supply-side resources, including the construction of new generating units, purchased power, cogeneration, and efficiency improvements. A recommended capacity resource plan is presented for each major service area, ERCOT, and for the state.

Finally, Chapter 7, the last chapter of this volume, summarizes the results and findings from the Commission staff's analysis and provides policy recommendations and topics for further research.

CHAPTER TWO

ECONOMIC OUTLOOK AND IMPACTS ON ELECTRIC ENERGY IN TEXAS

The modest economic recovery in Texas continues. Noteworthy is the diversified nature of the economy compared with the dominance of the mining and extraction sectors, a hallmark until the mid--1980's. A key issue to be addressed, however, is the expected impact on the economy of the recent events in the Middle East and the resulting rise in oil prices.

The Texas Economy

The economic outlook for Texas, presented in the 1988 **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas**, indicated that not only was the recession over but the future looked bright. Indeed, there is ample evidence to believe that Texas continues to recover from the effects of the drastic reduction in oil prices in early 1986. It even appears that Texas is outpacing the U.S in a number of areas based on the growth of various economic indicators.

Between 1970 and 1986 the Texas economy became heavily dependent on the health of the mining and extraction sectors. With the price of oil in the $25 per barrel range, Texas, led by growth in oil exploration and refining, experienced an economic boom. However, this dependence would have a downside. Because of the increasing dependence of the economy on the revenue from the oil patch, the fall in oil prices in 1986 produced a ripple effect felt throughout virtually all sectors of the economy. Two sectors hit extremely hard were real estate and construction.

While the boom occurring between 1970 and 1986 was driven by the growth in the energy industry, the current recovery is characterized by the absence of growth in the once dominant mining and extraction sector. As a matter of fact, the Texas economy is exhibiting increasing diversity.

Analysts predict that the services sector will exhibit the strongest growth over the next few years. Employment in medical services as well as business services will increase noticeably as corporations continue to relocate their headquarters to Texas. Growth in the high-tech manufacturing sector, especially in computers and defense, continues to act as a cushion as the economy adjusts to lower, yet more sustainable, levels of activity in the mining and extraction sectors.

In general, some economists see Texas outperforming, if only modestly, the U.S. across a variety of economic indicators. Texas is expected to experience higher rates of growth in non-agricultural employment, personal income, real output, and productivity. Additionally, while the U.S. as a whole has a lower unemployment rate than Texas, this gap is expected to close. Clearly then, Texas continues to recover from the fall in oil prices in 1986. While the recovery is modest, it appears sustainable.

Recent events in the Middle East, however, merit attention. The repercussions of the rise in oil prices, reaching $38 per barrel in late August, as a result of the Iraqi invasion of Kuwait will be felt throughout the U.S. and the world. The sluggishness in the U.S. economy, which began even before recent events in the Middle East, will only be exacerbated with the steep rise in the price of oil.

Key to the impact of recent events will be the level at which prices reach equilibrium. Analysts predict prices ranging between $24 and $33 per barrel, depending on how the conflict is resolved. On the high side is resolution by military force while the low-end price reflects a peaceful resolution to the conflict.[1]

It is generally agreed that if oil prices settle in this range, Texas will see modest increases in real output and in employment. The increasing diversity reflected in the state's economy, however, dampens potential benefits of higher oil prices for a number of reasons. First, the state no longer has the infrastructure in place to take full advantage of higher oil prices. Second, many of the growth industries in the state, including manufacturing, services, and the petrochemical industry, benefit from lower, not higher, oil prices. So, while Texas will not see a boom from higher oil prices, the state is also

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1 As this report goes to press the intensive four-day ground war in Kuwait and Iraq has concluded. World oil prices have fluctuated in the $18 to $22 per barrel range during the past few weeks and are expected to remain near $20 per barrel in the near term. Lower oil prices are likely to moderate the U.S. recession and to improve the outlook for Texas slightly, all things considered. This recent information on world oil prices has no significant impact on the forecast contained in this report.

positioned to avoid a severe recession if oil prices eventually fall. The recovery in Texas is expected to continue even in light of a sluggish national economy and recent events in the Middle East. Diversification of the Texas economy will continue and, while preventing a new "oil boom" with the rise in oil prices, ensure a cushion if prices eventually fall.

Macroeconomic Factors Affecting Electricity Demand

One factor affecting demand for electricity is population. Real per capita income also plays an important role in determining trends of future electricity consumption. If personal income is growing at a faster pace than population, the average person expects to enjoy an overall higher standard of living. A higher standard of living generally translates into an increase in comfort and convenience, which in many instances leads directly to an increase in electricity consumption. Finally, shifts in non-agricultural employment have implications with respect to electricity consumption within the commercial and industrial sectors. If employment is on the rise, it is assumed that the commercial and industrial sectors are experiencing growth. This growth may take the form of increased production or the entry of new businesses, both of which imply a rise in the demand for electricity.

Economic and demographic variables such as population, personal income, and nonagricultural employment are utilized in the econometric and end-use models by the Commission staff to forecast electricity demand. The Commission staff analyzes a number of different forecasts of these variables in order to derive its vision of future trends in electricity demand. These projections (or combination thereof) are then used in the staff models to form its forecast of future electricity consumption. The staff models and the projections used as inputs are discussed in detail in Volume III of this report.

Sources for the projections considered by the staff include the Baylor University Forecasting Service, produced under the supervision of Dr. M. Ray Perryman, Data Resources, Inc. (DRI), Wharton Econometric Forecasting Associates (WEFA), and the Texas Comptroller of Public Accounts. Tables 2.1 through 2.3, which contain the specific forecasts made by the above sources for the period from 1989 through 1999, are provided for comparison purposes. These tables illustrate the differences among the different forecasting sources. It should be noted that while the actual projections are important, the more meaningful comparisons are drawn between the expected growth rates of the indicators.

TABLE 2.1

HISTORICAL VALUES AND PROJECTIONS
OF POPULATION FOR THE STATE OF TEXAS

Year	Baylor (1)	DRI (2)	Wharton (3)	Texas Comptroller (4)
1980	14,339,000	14,339,000	14,339,000	14,339,000
1981	14,763,000	14,763,000	14,763,000	14,763,000
1982	15,372,000	15,372,000	15,372,000	15,372,000
1983	15,814,000	15,814,000	15,814,000	15,814,000
1984	16,079,000	16,079,000	16,079,000	16,079,000
1985	16,383,000	16,383,000	16,383,000	16,383,000
1986	16,682,000	16,682,000	16,682,000	16,682,000
1987	16,778,000	16,778,000	16,778,000	16,778,000
1988	16,837,000	16,900,000	16,997,000	16,859,900
1989	16,994,000	17,000,000	17,214,600	17,017,000
1990	17,181,000	17,200,000	17,443,900	17,202,400
1991	17,370,000	17,400,000	17,693,500	17,395,500
1992	17,579,000	17,600,000	17,957,700	17,607,200
1993	17,881,000	17,900,000	18,227,600	17,825,200
1994	18,180,000	18,100,000	18,495,400	18,060,000
1995	18,477,000	18,300,000	18,768,200	18,289,300
1996	18,769,000	18,500,000	19,048,500	18,491,700
1997	19,059,000	18,600,000	19,327,400	18,670,600
1998	19,344,000	18,700,000	19,612,500	18,830,500
1999	19,625,000	18,900,000	19,900,500	18,977,000
Annual Growth Rate (1988-1999)	1.40%	1.02%	1.45%	1.08%

Sources:

(1) Texas Economic Forecast: M. Ray Perryman, Ph.D.; May 1990

(2) DRI/McGraw-Hill: Regional Information Service-Southern Focus; Winter 1989-1990

(3) Regional Forecast Long-Term State Tables: Wharton Econometric Forecasting Associates; Fall 1989

(4) Comptroller of Public Accounts for the State of Texas, Regional Economic Forecast, May 1990

TABLE 2.2

HISTORICAL VALUES AND
PROJECTIONS OF NON-AGRICULTURAL EMPLOYMENT
FOR THE STATE OF TEXAS

Year	Baylor (1)	DRI (2)	Wharton (3)	Texas Comptroller (4)
1980	5,851,300	5,851,300	5,851,300	5,851,300
1981	6,180,000	6,180,000	6,180,000	6,180,000
1982	6,263,400	6,263,400	6,263,400	6,263,400
1983	6,193,600	6,193,600	6,193,600	6,193,600
1984	6,492,300	6,492,300	6,492,300	6,492,300
1985	6,663,100	6,663,100	6,663,100	6,663,100
1986	6,564,200	6,564,200	6,564,200	6,564,200
1987	6,516,900	6,516,900	6,516,900	6,516,900
1988	6,646,900	6,647,000	6,647,700	6,677,200
1989	6,781,800	6,782,800	6,774,900	6,810,600
1990	6,913,100	6,914,400	6,876,300	6,917,900
1991	7,050,800	7,056,900	7,022,200	7,049,700
1992	7,188,100	7,182,700	7,204,100	7,208,200
1993	7,312,800	7,301,700	7,364,000	7,378,000
1994	7,437,300	7,434,600	7,510,000	7,563,100
1995	7,562,700	7,560,200	7,666,500	7,739,600
1996	7,688,500	7,686,800	7,811,300	7,898,200
1997	7,814,700	7,807,800	7,954,200	8,036,900
1998	7,940,700	7,915,200	8,103,700	8,172,200
1999	8,066,400	8,002,900	8,290,700	8,306,000
Annual Growth Rate (1988-1999)	1.95%	1.87%	2.23%	2.21%

Sources:

(1) Texas Economic Forecast: M. Ray Perryman, Ph.D.; May 1990

(2) DRI/McGraw-Hill: Regional Information Service-Southern Focus; Winter 1989-1990

(3) Regional Forecast Long-Term State Tables: Wharton Econometric Forecasting Associates; Fall 1989

(4) Comptroller of Public Accounts for the State of Texas, Regional Economic Forecast, May 1990

TABLE 2.3

HISTORICAL VALUES AND
PROJECTIONS OF PERSONAL INCOME
FOR THE STATE OF TEXAS

	Baylor		DRI		Wharton		Texas Comptroller		
Year	Nominal Personal Income	Real Personal Income	Nominal Personal Income	Real Personal Income	Nominal Personal Income	Real Personal Income	Nominal Personal Income	Real Personal Income	Deflator
1980	140,500	213,612	140,500	213,612	140,500	213,612	140,500	213,612	0.658
1981	164,220	225,237	164,220	225,237	164,220	225,237	164,220	225,237	0.729
1982	179,670	230,927	179,670	230,927	179,670	230,927	179,670	230,927	0.778
1983	188,890	235,205	188,890	235,205	188,890	235,205	188,890	235,205	0.803
1984	205,510	246,167	205,510	246,167	205,510	246,167	205,510	246,167	0.835
1985	220,690	255,783	220,690	255,783	220,690	255,783	220,690	255,783	0.863
1986	225,200	255,828	225,200	255,828	225,200	255,828	225,200	255,828	0.880
1987	232,780	255,233	232,780	255,233	232,780	255,233	232,780	255,233	0.912
1988	245,650	259,562	245,600	259,509	246,000	259,932	245,648	259,560	0.946
1989	264,530	264,530	264,700	264,700	265,000	265,000	264,522	264,522	1.000
1990	282,970	272,799	282,000	271,864	281,000	270,899	281,187	271,080	1.037
1991	302,960	278,464	302,300	277,857	302,200	277,765	299,404	275,195	1.088
1992	325,710	283,510	325,600	283,414	327,300	284,894	322,944	281,102	1.149
1993	348,840	288,988	350,300	290,198	351,900	291,523	349,436	289,482	1.208
1994	374,630	294,573	377,000	296,436	378,900	297,930	378,485	297,604	1.272
1995	403,160	301,011	405,800	302,982	408,900	305,297	409,444	305,703	1.339
1996	433,240	307,169	437,400	310,119	436,300	309,339	441,504	313,028	1.410
1997	465,510	313,229	471,900	317,529	466,700	314,030	475,006	319,619	1.486
1998	500,570	319,951	509,300	325,531	499,500	319,267	510,296	326,168	1.565
1999	537,170	326,044	548,200	332,739	545,000	330,796	547,865	332,535	1.647
*	7.38%	2.10%	7.58%	2.29%	7.51%	2.22%	7.57%	2.28%	

* - Annual Growth Rate (1988-1999)

Real Values are in 1989 dollars

The deflator is constructed using the Consumer Price Index from WEFA

Sources:

(1) Texas Economic Forecast: M. Ray Perryman, Ph.D.; May 1990

(2) DRI/McGraw-Hill: Regional Information Service-Southern Focus; Winter 1989-1990

(3) Regional Forecast Long-Term State Tables: Wharton Econometric Forecasting Associates; Fall 1989

(4) Comptroller of Public Accounts for the State of Texas, Regional Economic Forecast, May 1990

As shown in Table 2.1, DRI among the sources is projecting the lowest annual growth rate in population for Texas through 1999. DRI's projections of non-agricultural employment are also lower than other sources (see Table 2.2). However, they expect the highest annual growth rates in personal income for Texas over the next ten years (Table 2.3). The Commission staff has used a more optimistic view of the future of Texas population and employment than that projected by DRI. See Volume III for more detail on inputs to staff models.

Service Area Macroeconomic Variables

As mentioned previously, the PUCT staff's econometric and end-use models used to project electricity sales and demand rely on a number of economic and demographic variables. Population, nonagricultural employment, and personal income must be forecasted and used as inputs to the models of electricity demand the staff estimates for major generating utilities in Texas. Table 2.4 contains the staff-projected estimates of annual growth rates for the variables mentioned above for the various utility service areas.

There is significant variation in the economic and demographic variables across the various service areas. Annual growth in total population ranges from .06 percent in the Texas service area of GSU to 2.49 percent for the area served by the COA. Annual growth in non-agricultural employment in the Texas portion of the GSU service area is 1.14 percent while growth reaches 2.58 percent in the BEPC service area. Not surprising is that GSU's Texas service area has the lowest growth in real personal income with an annual rate of .66 percent. Annual growth in real personal income in the HL&P service area is projected to be the most robust with a rate of 2.90 percent.

Weather

Weather can be a significant determinant in the consumption of electric power. This causal relationship between weather and power usage is for the most part a result of the operation of temperature sensitive equipment such as air conditioners, heat pumps, and space heaters to satisfy a comfort-conscious society. Electric utilities and regulators alike are concerned with the tracking of weather patterns and any anomalies in these patterns in the development of sales and load forecasts.

TABLE 2.4

STAFF-PROJECTED GROWTH RATES
SERVICE AREA ECONOMIC/DEMOGRAPHIC VARIABLES
1988/1999 (Percent)

Utility Service Area	Total Population	Non-Agricultural Employment	Nominal Personal Income	Real Personal Income
TU ELECTRIC	1.47	1.88	7.40	2.12
HL&P	1.52	2.29	8.23	2.90
GSU-TX	0.06	1.14	5.86	0.66
CPL	1.65	2.18	7.55	2.27
CPS	1.31	1.80	6.96	1.70
SPS-TX	0.94	1.64	7.22	1.94
SWEPCO-TX	0.83	1.34	6.83	1.58
LCRA	1.59	2.19	7.91	2.61
COA	2.49	2.39	7.99	2.68
WTU	1.27	1.72	7.23	1.95
EPE-TX	1.33	1.99	7.31	2.03
TNP-PANH	0.91	1.47	7.23	1.95
TNP-NORTH	1.46	1.90	7.40	2.12
TNP-CENT	1.49	1.93	7.44	2.16
TNP-SOUTH	0.73	1.37	7.08	1.81
TNP-WEST	1.60	1.77	7.19	1.92
BEPC	2.19	2.58	8.03	2.72
TEXAS				
LEVEL (1988)	16,837,000	6,646,900	245,650	259,562
LEVEL (1999)	19,625,000	8,066,400	537,170	326,044
GROWTH RATE	1.40	1.78	7.38	2.10
NON-TEXAS				
EPE-NTX	1.25	1.63	7.35	2.08
GSU-NTX	0.65	1.19	6.38	1.14
SWEPCO-NTX	0.15	0.79	5.89	0.68
SPS-NTX	0.94	1.64	7.22	1.94

Sources:

Texas Economic Forecast: M. Ray Perryman, Ph.D.; May, 1990

U.S. Department of Commerce, Bureau of the Census; County Population Estimates, January 1988, August, September, December, 1987

U.S. Bureau of Economic Analysis; Local Area Personal Income, Volume IV Southeast Region 1982-1987

Oklahoma Employment Security Commission; County Employment And Wage Data; November 1989

Arkansas Employment Security Commission; Labor Force Statistics; May 1989; August 1983

New Mexico Department of Labor; Non-Agricultural Wage And Salary Employment; March 1990; May 1981

Louisiana Department of Labor; Employment And Wages; October 1987; November 1986; October 1983; November 1980; August 1987

Kansas Department of Labor; Covered Employment Data; August 1990

Background The vast majority of electric utilities obtain their weather information from the National Oceanic and Atmospheric Administration (NOAA). Although several types of weather data are furnished including dry bulb temperatures, precipitation, and minutes of sunshine, the data series of choice to determine electricity consumption are heating degree days (HDD's) and Cooling degree days (CDD's). The two basic formulas follow:

HDD = BASE TEMP - [(MAX TEMP + MIN TEMP) / 2]

CDD = [(MAX TEMP + MIN TEMP) / 2] - BASE TEMP

Where: MAX TEMP = Daily Maximum Temperature
MIN TEMP = Daily Minimum Temperature
BASE TEMP = 65°F

Normal Weather While actual degree days series are used to estimate the weather responsiveness of electricity sales, some measure of expected or normal weather is needed to weather-normalize sales and to develop forecasts. The normal monthly HDD's and CDD's presented in Tables 2.5 and 2.6 employ a base temperature of 65°F. This is the base temperature used by NOAA and is presented here for comparative purposes. Other base temperatures are chosen by the utilities depending on their understanding of the temperature sensitivity of electric equipment. For example, CPS develops CDD's using a base temperature of 72°F while still using the 65°F base for HDD's.

Normal weather values are developed by calculating the average of recorded weather data over a specified period of time. The number of years of data used to develop normal degree days are generally based upon the availability of reliable data and the possible effects of changing long-term weather conditions. For example, TNP, HL&P, and TU Electric use 30 years of data to develop normal monthly degree days while CPS uses 25 years. However, the resulting normal degree days vary little when more than a minimum of ten years of data is used in their calculation.

COA and HL&P are examples of utilities that use weather data from only one weather station. However, Texas is both a large and a climatically diverse state. In situations where the weather varies dramatically throughout a utility's service area, several weather sites are employed, aggregated, and weighted. For example, TNP weights degree days

TABLE 2.5

AVERAGE NORMAL MONTHLY HEATING DEGREE DAYS

Month	COA	CPL	CPS	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU	TNP	BEPC
Jan	505	293	478	648	443	415	505	856	583	678	662	493	691
Feb	347	285	339	447	435	297	347	663	444	481	475	501	560
Mar	203	157	164	300	279	145	203	514	316	287	320	225	265
Apr	41	58	38	114	124	27	41	215	75	82	96	109	121
May	0	7	1	15	43	1	0	57	0	11	11	25	15
Jun	0	0	0	0	6	0	0	3	0	0	0	6	1
Jul	0	0	0	0	1	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	2	11	1	0	0	19	0	7	8	0	4
Oct	37	3	34	100	27	22	37	181	69	67	92	5	49
Nov	221	34	194	393	107	147	221	532	285	299	361	62	238
Dec	406	154	391	619	285	329	406	769	512	551	575	241	523
Total	1,760	991	1,641	2647	1,751	1,383	1,760	3,809	2,284	2,463	2,600	1,667	2,467

WTU:

1) Abilene District weather information is used in place of Stamford District.
2) Total system degree days weighted by number of customers per district.

LCRA:

1) COA degree days are used as a proxy for LCRA.

TNP:

1) HDD's are derived from each of TNP's Texas Divisions.
2) Weather data are weighted by customer count per Division.
3) HDD's are based upon historical data from 1960 to 1989.

HL&P:

1) Data are for Hobby Airport, 1960 to 1989.

TU:

1) Degree days data are weighted by each weather site's respective percentage of total Residential single-metered customers.
2) HDD's are based upon historical data from 1959 to 1988.

BEPC:

1) Based upon wholesale billing period.

CPS:

1) Data are for 1965 to 1989, inclusive.

TABLE 2.6

AVERAGE NORMAL MONTHLY COOLING DEGREE DAYS

Month	COA	CPL	CPS	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU	TNP	BEPC
Jan	12	41	9	0	25	16	12	0	0	1	0	0	1
Feb	16	39	14	1	19	17	16	0	8	4	0	0	3
Mar	63	66	68	8	46	61	63	6	31	28	31	0	23
Apr	152	168	177	60	108	175	152	29	105	105	104	103	81
May	307	310	327	219	214	334	307	134	253	264	249	234	213
Jun	498	461	495	465	376	482	498	346	444	478	465	421	452
Jul	611	554	606	537	485	568	611	446	574	624	579	542	608
Aug	605	607	595	477	493	563	605	288	570	611	546	591	640
Sep	426	578	432	288	477	435	426	186	363	385	329	536	454
Oct	186	411	203	65	321	223	186	34	140	139	113	311	172
Nov	32	225	59	2	157	77	32	0	12	25	11	126	39
Dec	6	96	14	0	69	24	6	0	0	3	0	0	2
Total	2,914	3,556	2,999	2,122	2,790	2,975	2,914	1,469	2,500	2,667	2,427	2,864	2,688

WTU:

1) Abilene District weather information was used in place of Stamford District.
2) Total system degree days weighted by number of customers per district.

LCRA:

1) COA degree days are used as a proxy for LCRA.

TNP:

1) CDD's are derived from each of TNP's Texas Divisions.
2) Weather data are weighted by customer count per Division.
3) CDD's are based on historical data from 1960 to 1989.

HL&P:

1) Data are for Hobby Airport, 1960 to 1989.

TU:

1) Degree days data are weighted by each weather site's respective percentage of total Residential single-metered customers.
2) CDD's are based upon historical data from 1959 to 1988.

BEPC:

1) Based upon wholesale billing period.

CPS:

1) Data are for 1965 to 1989, inclusive.

by the total number of customers for each of the Company's Divisions, while TU Electric uses the percentage of residential single-metered customers. In addition, weather stations are not always located in areas that best represent the customers served. As an example, WTU substitutes Abilene District weather information in place of the rural Stamford District to better reflect service area population characteristics.

The SPS service area experiences the highest total number of HDD's for the normal year while the CPL service area has the lowest. Conversely, SPS experiences the lowest total number of CDD's for the normal year. SPS has the lowest number of monthly normal CDD's (446) during the summer. While CPL experiences the highest total number of CDD's for the normal year, TU Electric has the highest number of monthly normal CDD's during the summer. Several other utilities exhibit a similar number of CDD's during the peak cooling months of July and August.

Weather Impacts on Electricity Demand

As a result of the large impact of weather on electricity use, weather normalization and energy forecasting have become two important activities performed by the utility industry. Weather normalization is critical to the load forecasting process. Without weather normalization, actual results and any trends may be misleading. Utilities and regulatory agencies are, therefore, concerned with keeping an account of weather patterns and also estimating the effects on sales due to abnormal weather.

Demand for electricity is assumed to be influenced by (1) economic and demographic variables and (2) weather. The influence of weather on electricity consumption is a consequence of increased use of temperature-sensitive equipment such as air conditioners, heat pumps, and space heaters. The effects of weather on electricity demand are most evident during the extremes of winter and summer. Abnormal weather events and their effects on electricity consumption tend to cancel each other out in the long run. Therefore, the price of electricity and other economic and demographic variables (non-weather variables) are considered to be the major determinants of long-run trends in electricity demand.

Geography

Developing models of weather's influence on electricity sales is a particular challenge for Texas electric utilities due to the assortment of conditions which influence weather variables. Second only to California, Texas has the most variety in physical setting, temperature, and annual rainfall. Altitudes in Texas range from sea level to over 8,700 feet. Average annual temperatures range from a high of over 74°F to a low of less than 56°F. Average annual rainfall ranges from more than 56 inches to less than 8 inches. In addition, differences in the types of soils and vegetation, annual sunshine, and humidity provide a variety of environmental conditions.

Heating Degree Days. Heating Degree Days (HDD's) serve as an index of the amount of heat required to maintain a comfortable indoor temperature level during the winter months. HDD's clearly reflect climatic conditions. For example, the Chicago area has a total of 6,100 annual normal HDD's while the HL&P service area has only 1,383. In Texas, where heating is relatively less important than in the northern and western United States, the range is from 3,809 per year for SPS to 991 per year for CPL.

The estimated coefficients obtained for HDD's and for CDD's from regression equations only partly reflect the effects of weather on the consumption of electricity. Factors such as relative humidity, appliance saturation, personal income, and availability of alternative energy sources are also influential. For illustrative purposes, a comparison of climatic extremes is presented. The estimated regression coefficients for HDD's derived from the Commission's econometric models for HL&P and EPE are 0.000533 and 0.000208, respectively. While the EPE service area plainly exhibits more wintery weather than HL&P's (normal monthly HDD's for EPE are nearly double that of HL&P's), EPE's low electric heat appliance saturation and lower personal income result in a lower coefficient estimate.

Cooling Degree Days. Cooling degree days (CDD's) serve as an index of air conditioning requirements during the summer months. The greater the number of CDD's, the more energy is needed to maintain indoor temperatures at a comfortable level.

The electric utilities in Texas are summer peaking. Air conditioning is a primary contributor to peak load. On a statewide basis, cooling requirements comprise nearly 80% of residential and 50% of commercial peak demand. In addition, the peak demands for the residential and commercial classes often occur at the same time during the afternoon in the late summer months.

There is general agreement regarding the effect of summer weather on electricity demand in Texas, but the magnitude of the impact varies across utility service areas. This is evident upon comparison of the estimated regression coefficients for residential CDD's.

Again, looking at climatic extremes, the results from the previous staff Load Forecast show the estimated regression coefficient for residential CDD's for HL&P to be 0.000695, while the same coefficient for EPE is only 0.000318. The service area of HL&P is characterized by long and extremely humid summers requiring the use of electricity-intensive refrigerated air conditioning. By contrast, EPE's service area, in the high desert, has sunny but dry summers punctuated by monsoon rains. Customers in this climate are able to use evaporative cooling, which is less energy-intensive than refrigerated air conditioning. Furthermore, HL&P currently has the highest saturation of refrigerated air conditioning statewide while EPE has the lowest.

Shoulder Months. Although the demand for electricity is clearly influenced by weather conditions, the extent of this influence changes throughout the year. Months not requiring heating or cooling are called shoulder months and vary depending upon the service area. In Texas, the months of March and April in the spring and October and November in the fall are generally the shoulder months. Although the weather in these months may be abnormal, there is usually little, if any, effect on the demand for electricity.

Summary The demand for electricity is determined by several variables including weather. HDD's and CDD's serve as separate indices for heating and cooling requirements, respectively. Weather normalization is considered to be a critical part of the load forecasting process. However, while the effect of weather is important, its maximum influence is during summer and winter. In the long term, the effects of abnormal weather events on electricity consumption tend to cancel out over time and are eclipsed by the influence of long-term trends in price and economic activity.

Electric Energy

Electricity has qualities that make it an especially attractive form of energy. It has a well-defined engineering structure while being both clean and flexible in terms of its end uses. Technological advances have made possible many new opportunities for taking advantage of electric power. In the past, these advances were generally associated with a similar increase in the consumption of electricity. While a continued increase in the use and application of electric energy is expected, future electricity consumption is expected to be partially offset by increases in efficiency brought about by programs such as the National Appliance Energy Conservation Act of 1987.

Electricity Consumption

Electricity consumption data may be analyzed by studying (1) per capita electricity consumption (Table 2.7) and (2) average annual residential electricity consumption (Table 2.8). Per capita electricity consumption is defined as total electricity consumption divided by total population of the utility's service area. The annual growth in this variable reflects the change in electricity consumption over all customer classes. The ten-year change reflects the compounded growth rate in per capita electricity consumption.

Average annual residential electricity consumption is defined as total electricity consumption for the residential class divided by the number of residential customers. The growth rates in this variable reflect only the change in electricity consumption per residential customer. Growth rates in average residential electricity consumption tend to be lower than in per capita consumption. Per capita electricity consumption includes both commercial and industrial customers. While these customers may be smaller in number, they tend to be larger consumers of electricity and are more sensitive to changes in economic conditions. In addition, although the effects of conservation programs are not included in this Table, these programs are anticipated to have an especially significant impact on residential electricity consumption in the future.

As shown in Table 2.7, the changes in per capita electricity consumption between 1979 and 1989 vary a great deal among Texas electric utilities. Per capita electricity consumption in the areas served by HL&P and TNP experienced the largest decreases while GSU and CPL experienced more moderate decreases. These service areas probably felt the impact of the decrease in oil prices and the ensuing Texas economic recession more than other areas in the state. A contributing factor was the loss of industrial load that occurred from self-generation. Several service areas, led by the Central Texas utilities of COA and LCRA, showed significant economic growth between 1979 and 1986. These service areas were less affected by the economic recession and loss of industrial load over the last few years.

TABLE 2.7

ANNUAL PER CAPITA ELECTRICITY CONSUMPTION

Electric Utility	1979 (KWH/ Person)	1989 (KWH/ Person)	Ten-Year Change 1979-1989 (Percent)	Annual Change 1979-1989 (Percent)	1999 (KWH/ Person)	Ten-Year Change 1989-1999 (Percent)	Annual Change 1989-1999 (Percent)
TU	12,349	15,698	27.1%	2.4%	16,913	7.7%	0.7%
HL&P	17,465	15,449	-11.5%	-1.2%	16,308	5.6%	0.5%
GSU	17,251	16,725	-3.0%	-0.3%	18,405	10.0%	1.0%
CPL	8,045	7,963	-1.0%	-0.1%	9,099	14.3%	1.3%
CPS	7,163	9,552	33.4%	2.9%	12,246	28.2%	2.5%
SPS	12,258	15,392	25.6%	2.3%	15,391	0.0%	0.0%
SWEPCO	12,023	16,229	35.0%	3.0%	NA	NA	NA
LCRA	7,318	10,334	41.2%	3.5%	11,743	13.6%	1.3%
COA	7,584	10,434	37.6%	3.2%	NA	NA	NA
WTU	11,598	14,422	24.3%	2.2%	15,532	7.7%	0.7%
EPE	5,507	5,798	5.3%	0.5%	6,071	4.7%	0.5%
TNP	11,180	10,291	-8.0%	-0.8%	10,155	-1.3%	-0.1%
BEPC	NA	7,960	NA	NA	9,088	14.2%	1.3%

Source:

These data were provided by the utilities in response to an informal Commission staff request in 1990

Note:

Projected values are not adjusted for appliance standards or utility-sponsored programs

Self-generation of electricity is not included in the deriviation of per capita electricity consumption

BEPC:

(1) Based upon number of residential meters in 1983 and 1988 surveys.

GSU:

1) Total Texas retail sales divided by Texas service area population.
2) Service area is based on the Beaumont-Port Arthur metropolitan areas and the sum of seven counties north of Houston.

TABLE 2.8

AVERAGE ANNUAL RESIDENTIAL ELECTRICITY CONSUMPTION (MWH Per Customer)

Year	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	COA	WTU	EPE	TNP	BEPC
1980	14.96	14.22	13.17	9.90	9.69	7.86	11.32	10.52	9.56	9.00	5.83	12.13	10.10
1981	13.41	13.59	12.79	9.92	9.33	7.40	10.59	10.07	9.27	8.72	5.63	11.37	9.44
1982	13.74	13.50	13.02	10.11	9.77	7.60	10.91	10.89	10.00	9.11	5.66	11.50	9.88
1983	13.30	11.76	12.10	9.49	9.20	7.79	10.45	10.46	9.41	8.95	5.63	10.69	9.70
1984	14.05	12.62	13.00	10.01	9.70	7.85	10.81	11.31	10.12	9.22	5.54	11.49	10.51
1985	14.11	12.96	12.80	10.32	10.01	8.00	11.14	11.41	10.32	9.18	5.54	11.68	10.62
1986	13.70	12.68	12.73	10.34	10.12	7.92	11.09	11.57	9.99	9.11	5.54	11.81	10.64
1987	14.05	12.81	12.82	10.37	10.19	8.12	11.30	11.29	9.73	9.33	5.67	12.01	11.00
1988	14.42	13.16	13.03	10.92	10.86	8.33	11.43	11.81	9.91	9.51	5.87	12.47	1.53
1989	14.62	13.27	13.23	11.46	11.42	8.50	11.24	12.14	10.17	9.72	6.00	12.70	11.70
1990	14.59	13.23	13.22	10.89	11.15	8.50	11.45	11.34	10.13	9.76	6.06	12.10	11.69
1991	14.85	13.08	13.20	10.99	11.42	8.50	11.56	11.36	10.10	9.72	6.07	12.16	11.76
1992	15.06	12.91	13.26	10.95	11.64	8.50	11.51	11.45	10.13	9.80	5.75	12.21	11.86
1993	15.12	13.15	13.22	11.04	11.77	8.50	11.51	11.56	10.16	9.82	5.73	12.27	11.97
1994	15.18	13.26	13.22	11.15	11.84	8.50	11.51	11.69	10.20	9.92	5.71	12.33	12.07
1995	15.27	13.46	13.29	11.26	11.90	8.50	11.51	11.84	10.26	9.99	5.71	12.39	12.18
1996	15.40	13.57	13.35	11.36	11.97	8.50	11.51	11.99	10.32	10.05	5.75	12.44	12.29
1997	15.53	13.47	13.46	11.45	12.13	8.50	11.50	12.14	10.38	10.12	5.72	12.50	12.40
1998	15.68	13.50	13.48	11.54	12.19	8.50	11.49	12.33	10.45	10.18	5.72	12.56	12.51
1999	15.82	13.48	13.55	11.71	12.37	8.50	11.49	12.53	10.53	10.24	5.73	12.61	12.60
2000	15.98	13.38	NA	11.78	12.46	8.50	11.48	12.70	10.62	10.31	5.75	12.67	12.67
Annual Growth (Percent)													
80-89	-0.26%	-0.77%	0.05%	1.64%	1.84%	0.87%	-0.08%	1.60%	0.69%	0.86%	0.32%	0.51%	1.65%
89-99	0.79%	0.16%	0.24%	0.22%	0.80%	0.00%	0.22%	0.32%	0.35%	0.52%	-0.46%	-0.07%	0.74%
80-99	0.29%	-0.28%	0.15%	0.89%	1.29%	0.41%	0.08%	0.92%	0.51%	0.68%	0.09%	0.20%	1.17%

Source: These data were provided by the utilities in response to an informal Commission staff request in 1990

Note: Projected values are not adjusted for appliance standards or utility-sponsored programs

BEPC: 1) Actual historical values from 1980 to 1989 are not weather-adjusted
2) Projected data from 1990 to 2000
4) Projected data from Brazos Electric Cooperative Power Requirement Study, November 1989

GSU: 1) Historical and projected data are total system

COA: 1) Actual historical values from 1980 to 1989 are not weather adjusted
2) Projected data from 1990 to 2000

The projections from 1989 to 1999 in Table 2.7 show an increase in per capita electricity consumption for nine out of the eleven utilities providing data. The SPS service area shows a zero growth rate for the ten-year period. TNP is the only utility expected to show a decrease during the forecast period. An explanation for this decrease is the expected construction of many new dwellings within TNP's service area. While new dwellings are much more electricity intensive than the general housing stock, they are also designed to be more energy efficient than existing homes. Table 2.8 presents average annual residential electricity consumption and annual growth rates. CPS experienced the highest annual growth in average residential consumption over the years 1980 through 1989. This growth trend, followed closely by BEPC, is expected to continue over the next ten years. HL&P exhibited the most significant decline over the 1980 through 1989 period and is expected to show only moderate growth over the next decade. EPE, which currently has the lowest electricity consumption rate in the state, is anticipated to show the greatest decline in average annual residential electricity consumption during the years 1989 through 1999. Overall, a comparison between Tables 2.7 and 2.8 reveals that, on average, annual residential electricity consumption increased more slowly than annual per capita electricity consumption in Texas. A similar trend is expected over the next decade. The projected values in both Tables are not adjusted for appliance standards or utility-sponsored programs. These programs typically encourage lower electric energy consumption.

Trends in Electricity Prices

Tables 2.9, 2.10, and 2.11 show the historical prices for residential, commercial, and industrial classes, respectively, from 1975 through 1989 for 13 utilities in the state. The average prices are calculated by dividing each utility's total class revenues by total class sales. These values, therefore, represent average electricity prices rather than actual rates. During the period from 1976 to 1985, electricity prices in Texas steadily increased to the point where the 1985 price for residential, commercial, and industrial classes was twice that of the 1975 price. This growth can largely be attributed to the addition of generating capacity and an increase in fuel prices. In 1985, fuel prices began to stabilize, but only temporarily. The Texas economic recession began to clearly manifest itself in 1986. Average electricity prices in the residential and commercial sectors fell by as much as 25% in one year. From 1987 through 1989 prices have generally stabilized. However, different regions in Texas and, therefore, different utilities, have recovered from the economic downturn to varying extents, and in some cases prices have continued to decrease.

TABLE 2.9

AVERAGE RESIDENTIAL ELECTRICITY PRICES*

(Cents per KWH)

Electric Utility	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
TU	2.57	3.04	3.32	3.57	3.87	4.42	5.59	6.21	6.48	6.81	6.89	6.22	6.24	6.37	6.42
HL&P	2.38	2.83	3.09	3.36	4.09	5.00	6.29	7.76	8.25	8.14	8.30	7.32	7.34	7.53	7.97
GSU	2.69	3.02	3.39	3.68	4.09	4.67	5.86	6.84	7.74	7.89	9.49	7.11	7.07	7.41	7.54
CPL	3.96	4.44	4.76	4.84	4.99	5.69	6.25	7.09	7.47	7.49	6.88	6.02	6.18	5.97	5.93
CPS	3.79	4.22	4.60	4.39	4.52	4.99	5.50	6.75	7.00	7.52	7.61	6.92	6.58	6.54	6.59
SPS(1)	3.28	3.85	4.21	4.44	4.77	5.70	6.42	7.16	7.67	7.50	7.15	7.32	7.27	6.92	6.71
SWEPCO	2.51	2.94	3.32	3.46	3.47	3.71	4.21	5.37	6.63	7.13	6.79	6.63	6.51	6.73	6.65
COA	3.08	4.38	3.27	5.50	4.81	5.26	5.41	5.79	6.17	6.87	6.07	6.16	5.68	6.89	6.55
WTU	3.39	3.78	3.97	4.13	4.32	4.50	5.36	6.62	7.31	7.45	7.70	6.94	6.43	7.81	8.30
EPE	3.54	3.92	3.99	4.93	5.85	6.73	8.51	8.92	10.18	10.43	9.90	9.83	8.65	8.72	8.96
TNP	2.65	3.06	3.42	3.60	4.05	4.74	6.26	7.49	7.93	7.96	8.12	6.89	7.23	7.23	7.27
BEPC	3.34	4.27	4.38	4.52	4.85	5.26	6.04	7.29	8.28	8.16	8.16	7.76	7.59	7.10	6.79
U.S.A.(2)	NA	NA	4.09	4.36	4.64	5.36	6.20	6.86	7.18	7.54	7.79	7.41	7.41	7.49	7.64

* Total residential revenue divided by total residential energy.

GSU, SPS, SWEPCO, and EPE include Texas customers only.

1 SPS 1975-1979 is Total Company. 1980 to present is Texas only.

2 Source: U.S. Department of Energy, Electric Power Monthly, Energy Information Administration, December 1989, page 54.

NOTE:

Values are for comparison purposes only. Actual rates vary according to load, usage, and tariff provisions.

LCRA is not included because retail sales are a minor portion of total sales.

TABLE 2.10

AVERAGE COMMERCIAL ELECTRICITY PRICES*

(Cents per KWH)

Electric Utility	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
TU	2.28	2.68	3.04	3.35	3.68	4.02	5.06	5.53	5.75	5.93	5.94	5.30	5.23	5.38	5.42
HL&P	2.08	2.63	2.91	3.20	3.97	4.68	5.73	6.98	7.36	7.21	7.23	6.18	6.17	6.38	6.70
GSU	2.48	2.76	3.16	3.39	3.67	4.14	5.04	5.88	6.35	6.42	7.77	6.72	7.04	7.19	7.13
CPL(2)	3.62	4.08	4.37	4.52	4.69	5.93	6.57	7.39	7.62	7.73	7.09	6.81	6.45	6.26	6.22
CPS	3.83	4.32	4.60	4.40	4.51	4.84	5.24	6.51	6.86	7.08	7.27	6.45	6.15	5.99	6.09
SPS(1)	2.55	3.16	3.56	3.80	4.11	4.96	5.85	6.36	6.88	6.90	6.53	6.86	6.86	6.58	6.31
SWEPCO	2.31	2.73	3.08	3.23	3.23	3.48	3.68	4.53	5.44	5.78	5.39	5.19	5.11	5.33	5.28
COA	2.45	3.70	2.92	4.69	5.03	5.46	5.83	6.52	6.85	7.65	6.79	7.28	5.87	6.70	6.28
WTU	2.94	3.31	3.69	3.89	4.04	4.23	4.87	6.02	6.58	6.67	6.44	5.60	5.16	6.03	8.30
EPE	3.15	3.62	3.69	4.27	4.89	5.94	7.53	7.99	9.12	9.25	8.61	8.44	7.35	7.34	7.67
TNP	2.60	3.06	3.43	3.70	4.10	4.67	6.03	7.17	7.33	7.30	7.44	6.08	6.52	6.54	6.58
BEPC	1.81	2.54	2.73	3.58	4.37	4.76	5.50	6.68	7.49	7.25	7.24	6.90	6.67	6.18	5.90
U.S.A.(3)	NA	NA	4.09	4.36	4.68	5.48	6.29	6.86	7.02	7.33	7.47	7.13	7.01	7.07	7.21

* Total commercial revenue divided by total commercial energy.
GSU, SPS, SWEPCO, and EPE include Texas customers only.

1 SPS 1975-1979 is Total Company. 1980 to present is Texas only.

2 CPL includes large and small industrial classes. Excludes cotton gin and large and small irrigation.

3 Source: U.S. Department of Energy, Electric Power Monthly, Energy Information Administration, December 1989, page 54.

NOTE:
Values are for comparison purposes only. Actual rates vary according to load, usage, and tariff provisions.

LCRA is not included because retail sales are a minor portion of total sales.

TABLE 2.11

AVERAGE INDUSTRIAL ELECTRICITY PRICES *

(Cents per KWH)

Electric Utility	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
TU	1.41	1.71	1.98	2.27	2.43	2.75	3.67	4.25	4.32	4.39	4.47	3.92	3.74	3.82	3.86
HL&P	1.23	1.61	1.87	2.13	2.70	3.21	4.11	5.16	5.22	5.06	4.94	3.91	3.62	3.75	3.87
GSU	1.31	1.54	1.94	2.18	2.53	2.85	3.42	3.84	3.83	3.84	4.93	3.89	4.06	3.93	3.97
CPL(2)	2.49	3.00	3.14	3.27	3.40	4.24	4.82	5.63	5.87	5.92	5.59	5.03	4.98	4.38	4.16
CPS	2.71	3.07	3.27	3.04	3.17	3.74	4.12	5.20	5.60	5.89	6.04	5.21	4.95	4.75	4.73
SPS(1)	1.49	1.90	2.44	2.67	3.00	3.47	3.85	4.39	4.81	4.74	4.38	4.48	4.36	4.30	3.99
SWEPCO	1.35	1.79	2.16	2.33	2.30	2.49	2.64	3.48	4.22	4.45	4.07	3.94	3.72	3.93	3.91
WTU	2.04	2.49	2.70	2.85	2.47	3.33	4.18	5.15	5.64	5.51	5.11	4.35	3.90	4.45	4.92
EPE	2.29	2.70	2.86	3.43	3.87	4.52	5.51	6.05	6.71	6.73	6.27	6.26	5.32	5.07	5.24
COA	NA	NA	NA	3.94	4.29	4.82	5.27	6.19	6.55	7.27	6.34	6.76	5.14	5.52	4.74
TNP	1.25	1.65	2.01	2.28	2.84	3.38	4.00	4.97	5.13	5.20	5.35	4.13	4.65	4.54	4.54
BEPC	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
U.S.A.(3)	NA	NA	2.50	2.79	3.05	3.69	4.29	4.95	4.96	5.04	5.16	4.90	4.72	4.62	4.72

* Total industrial revenue divided by total industrial energy.
GSU, SPS, SWEPCO, and EPE include Texas customers only.

1 SPS 1975-1979 is Total Company. 1980 to present is Texas only.

2 CPL includes large and small industrial classes. Excludes cotton gin and large and small irrigation.

3 Source: U.S. Department of Energy, Electric Power Monthly, Energy Information Administration, December 1989, page 54.

NOTE:

Values are for comparison purposes only. Actual rates vary according to load, usage, and tariff provisions.

LCRA is not included because retail sales are a minor portion of total sales.

According to the Tables, the average price for commercial classes increased the most: 151% during the years 1975 through 1989, was followed closely by the industrial classes at 150%. The increase for residential classes was 137%.

As exhibited by the Tables, EPE appears as the utility with the highest prices in all three customer classes for many years in the 1980's. Indeed, EPE is the only utility whose prices went above ten cents per KWH for residential rates. This is a result of EPE's reliance upon natural gas and the Palo Verde Nuclear generating station for most of its power. At the other end of the spectrum, SWEPCO and TU Electric have had among the lowest average residential and commercial prices. The lowest industrial prices are led by TU Electric, HL&P, SWEPCO, and GSU.

Another method for examining residential prices is to determine the annual average Residential rate for 1,000 KWH of usage. In Table 2.12, the average residential prices based on 1,000 KWH of usage are expressed in current (or nominal) terms. Table 2.13 presents the same prices in real terms (1989 dollars), using a Texas Consumer Price Index (CPI) as the deflator. The Texas average in both tables is a weighted average, based upon the number of Residential customers in each utility.

Electricity prices for 1,000 KWH will vary according to the design of the rates. In addition, actual annual consumption will vary from month to month during a typical year dependent upon such factors as climate, income, electricity prices, and the stock of appliances within the service territory.

While a direct comparison between Tables 2.12 and 2.13 with price per KWH (Table 2.9) may not be appropriate due to differing rate designs, many utilities exhibit similar relative rankings. EPE, HL&P, and SPS have the highest average residential prices in both sets of tables, while SWEPCO and TU Electric are among the lowest. Care should be taken when looking at ten-year averages. Current conditions may be masked. For example, SPS over the ten-year period exhibits the highest average rate; but recently, their rate approaches the state-wide average.

In Table 2.12, the effects of inflation on the weighted of average Texas residential prices between 1976 and 1989 is quite evident. Nominal electricity prices for 1,000 KWH of usage more than doubled from $34.17 to $71.30. However, when the effects of inflation are removed, as in Table 2.13, a direct comparison may be made as to how a particular utility's prices evolved during changing economic conditions. When electricity prices are

TABLE 2.12

AVERAGE RESIDENTIAL RATE SURVEY
(Nominal dollars per 1,000 KWH usage)

Year	COA	CPL	CPS	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU	TNP	BEPC	AVG.
1976	47.06	44.36	40.20	38.25	30.09	28.75	29.53	38.10	29.31	32.40	36.45	30.49	NA	34.17
1977	46.85	47.61	44.46	40.39	34.15	30.89	31.34	39.03	35.11	35.51	38.59	34.12	NA	37.09
1978	46.76	48.42	42.09	49.25	37.49	33.76	37.56	44.62	36.55	37.90	40.41	36.07	NA	39.38
1979	46.23	49.87	43.48	55.68	41.53	41.03	38.95	51.18	36.31	41.66	42.46	40.44	NA	43.37
1980	49.72	56.86	47.78	64.89	48.09	50.51	41.55	55.76	38.86	47.64	44.27	48.19	NA	49.88
1981	51.14	62.53	51.92	81.77	58.32	62.69	46.59	62.58	43.36	60.37	51.80	62.43	NA	60.13
1982	54.09	70.86	63.96	86.33	67.88	77.61	51.58	69.98	50.01	66.27	64.61	74.75	NA	69.40
1983	58.82	74.69	67.52	96.82	75.09	82.85	52.73	76.19	62.63	68.50	71.50	77.92	NA	73.88
1984	65.85	74.93	72.41	98.37	78.14	83.46	53.09	75.32	70.38	71.52	76.29	79.16	NA	76.20
1985	58.93	68.77	75.25	93.22	96.84	88.25	51.78	74.51	68.43	70.17	77.53	81.62	81.01	76.89
1986	58.83	66.02	67.05	92.21	76.09	80.43	44.84	74.81	64.85	65.76	69.93	68.14	78.05	70.78
1987	55.17	61.83	64.03	82.14	72.19	78.41	42.16	75.31	64.43	63.58	61.67	71.62	75.93	68.08
1988	66.61	59.69	63.75	81.90	76.31	78.71	50.90	73.39	64.00	65.94	78.42	72.39	71.84	69.90
1989	63.46	59.27	64.23	86.46	77.83	83.14	68.06	71.47	65.08	66.52	82.30	72.97	68.27	71.30

Notes:

1 Values for TU Electric Company prior to December 1984 are calculated using a weighted average of DPL, TESCO, and TPL rates based on annual revenues from 1977 to 1983.

2 The Texas Average is a weighted average based upon the number of Residential customers of each utility with the exclusion of LCRA and BEPC. These two utilities do not directly sell to residential customers. SPS is included after 1977. The number of Texas customers is used for multi-jurisdictional utilities.

3 A Texas CPI (1989 = 100) is developed based upon an average of the Dallas and Houston CPI's.

Source: U.S. & Texas Economic Indicators, Texas Water Development Board, 1990

TABLE 2.13

AVERAGE RESIDENTIAL RATE SURVEY
(Real 1989 dollars per 1,000 KWH usage)

Year	COA	CPL	CPS	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU	TNP	BEPC	AVG.
1976	100.99	95.19	86.27	82.08	64.57	61.70	63.37	81.76	62.90	69.53	78.22	65.43	NA	73.32
1977	93.70	95.22	88.92	80.78	68.30	61.78	62.68	78.06	70.22	71.02	77.18	68.24	NA	74.18
1978	86.11	89.17	77.51	90.70	69.04	62.17	69.17	82.17	67.31	69.80	74.42	66.43	NA	72.53
1979	75.05	80.96	70.58	90.39	67.42	66.61	63.23	83.08	58.94	67.63	68.93	65.65	NA	70.40
1980	70.83	81.00	68.06	92.44	68.50	71.95	59.19	79.43	55.36	67.86	63.06	68.65	NA	71.24
1981	65.73	80.37	66.74	105.10	74.96	80.58	59.88	80.44	55.73	77.60	66.58	80.24	NA	77.28
1982	65.33	85.58	77.25	104.26	81.98	93.73	62.29	84.52	60.40	80.04	78.03	90.28	NA	83.82
1983	68.80	87.36	78.97	113.24	87.82	96.90	61.67	89.11	73.25	80.12	83.63	91.13	NA	86.40
1984	74.32	84.57	81.73	111.03	88.19	94.20	59.92	85.01	79.44	80.72	86.11	89.35	NA	86.01
1985	64.55	75.32	82.42	102.10	106.07	96.66	56.71	81.61	74.95	76.86	84.92	89.40	88.73	84.21
1986	64.30	72.15	73.28	100.78	83.16	87.90	49.01	81.76	70.87	71.87	76.43	74.47	85.30	77.35
1987	58.75	65.85	68.19	87.48	76.88	83.50	44.90	80.20	68.62	67.71	65.68	76.27	80.86	72.50
1988	68.95	61.79	65.99	84.78	79.00	81.48	52.69	75.97	66.25	68.26	81.18	74.94	74.37	72.36
1989	63.46	59.27	64.23	86.46	77.83	83.14	68.06	71.47	65.08	66.52	82.30	72.97	68.27	71.30
AVG.	72.92	79.56	75.01	95.12	78.12	80.16	59.48	81.04	66.38	72.54	76.19	76.67	79.51	76.64

Notes:

1. Values for TU Electric Company prior to December 1984 are calculated using a weighted average of DPL, TESCO, and TPL rates based on annual revenues from 1977 to 1983.
2. The Texas Average is a weighted average based upon the number of Residential customers of each utility with the exclusion of LCRA and BEPC. These two utilities do not directly sell to residential customers. SPS is included after 1977. The number of Texas customers is used for multi-jurisdictional utilities.
3. A Texas CPI (1989 = 100) is developed based upon an average of the Dallas and Houston CPI's.

Source: U.S. & Texas Economic Indicators, Texas Water Development Board, 1990 adjusted for changes in the Consumer Price Index, the real increase in average electricity price is less than 2.5 percent. The effects of the Texas recession are also apparent.

EPE, GSU, and to lesser extents TU Electric and SWEPCO exhibit an inverted U-shape price curve for the real price of electricity over the 14 years.

Several utilites have reduced the real price of electricity to residential customers to levels below both the Texas weighted average and real 1976 prices. These utilities include COA, CPL, and CPS.

Fuel Supply

Fuel is typically an electric utility company's largest single expense. Recovery of fuel costs can account for more than 30 percent of a utility's overall revenues and, in periods of high fuel prices, fuel cost recovery can exceed 50 percent of revenues. This section discusses historical consumption of fuel used in generation and the fuel diversification which has occurred in Texas. Historical and projected fuel prices are also discussed. Finally, the projected availability of different fuels is reviewed.

Fuel Consumption Texas electric utilities' fuel requirements, including a historical summary of fuel consumption, are shown in Figure 2.1. By any measure, utilities in Texas, as a class, are both a major generator of electricity and a major consumer of fuel used in electricity generation.

In 1975, about 90 percent of the electricity generation in Texas was natural gas-fired. The 1990 generation mix projections include four fuels for thermal generating plants. Although still the dominant fuel, natural gas is projected to account for only 43 percent of the thermal generation by electric utilities serving Texas in 1990. Coal and lignite together are projected to account for about 48 percent of generation, and nuclear generation will provide about 6 percent.

Nearly 40 percent of the natural gas consumed for electric generation nationwide is consumed by utilities in Texas. Consumption of natural gas by utilities in Texas is more than twice that of those in California, the second largest natural gas consumer for electricity generation.

Texas utilities consume more than 8 percent of the total heating value of coal used in electricity generation nationwide. For electricity generation, coal consumption by utilities in Texas ranks first. It is followed by Ohio and Pennsylvania in second and third place, respectively.

Overall, Texas accounts for approximately 11 percent of the fossil fuel heating value consumed for electricity generation nationwide. This is equal to the combined fossil fuel heating values of Ohio and Pennsylvania, the runner-up states.

Although the primary fuels used for generation in Texas are natural gas and coal, nuclear generation is projected to account for a significant 10 percent of Texas electricity requirements by 1993. Seven Texas utilities own nuclear generation: CPL, HL&P, CPS, and COA (South Texas Project Units 1 and 2); GSU (partial ownership of River Bend); TU Electric (100% ownership of Comanche Peak Units 1 and 2); and EPE (partial ownership of Palo Verde Units 1, 2, and 3). All units are on commercial status except Comanche Peak Unit 2.

Fuel Diversification Utilities throughout Texas have undertaken fuel diversification programs to protect against severe disruptions because of the unavailability of any single fuel and allow the use of low-cost fuels. Continued fuel diversification is planned during the next ten years. According to the staff forecast additional base load capacity planned for operation during the next ten years includes the Comanche Peak Unit 2 nuclear unit, five lignite-fired units, and two coal-fired units. Also, several gas-fired, non-base load units are planned.

In many respects the increase in fuel diversification has been a very natural occurrence. The plants which operate as base load units and operate at the highest capacity factors should be exploiting the least expensive fuel available. Particularly in the 1970s and early 1980s, coal, lignite, and nuclear fuel were all less expensive and perceived to be more available than natural gas and oil; thus, construction of these types of plants was a logical result. Although the capital costs of coal, lignite, and nuclear plants are higher than gas- or oil-fired plants, long-term fuel economics tend to favor the overall production costs of coal and lignite plants for base load needs. Alternatively, the oil- and natural gas-fueled plants can be designed to be more flexible and better able to follow system load. The ability to track load coupled with the relatively higher cost of natural gas makes natural gas-fired units a better choice for cycling and peaking demand units in a generating system than for base load plants.

Because of a combination of existing take-or-pay contractual commitments for coal and coal transportation and the additon of more Texas nuclear generation within the next three years, growth in gas-fired generation will be reduced. This circumstance will displace a share of natural gas production that previously had been dedicated to the generation of electricity. The quantity of natural gas consumed for Texas electric generation is projected to decrease through 1993, continuing the downward trend which began in 1981. As indicated in Figure 2.1, gas consumed by Texas utilities for electric generation is not projected to show another year-to-year increase until 1994.

Trends in Fuel Prices

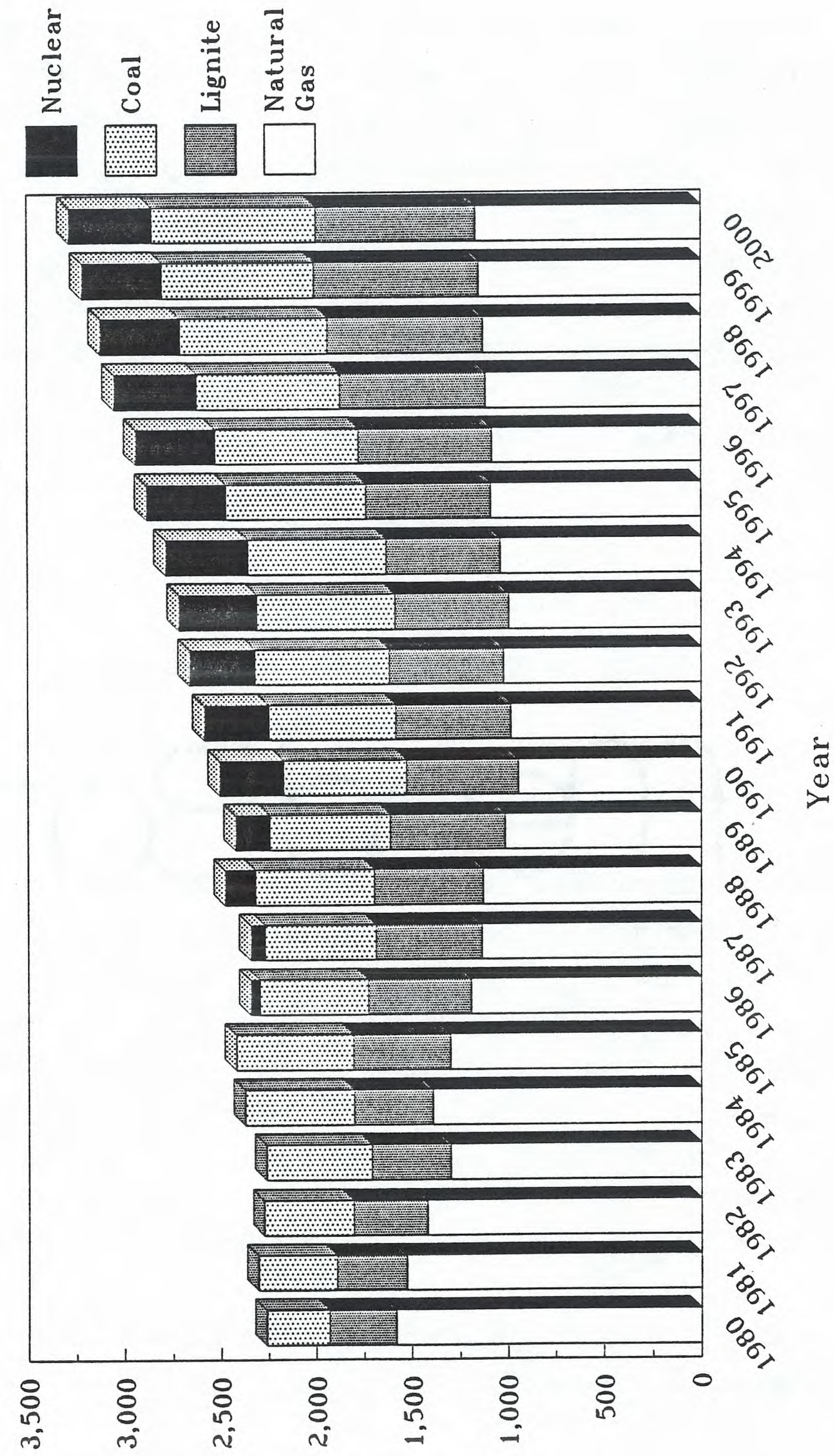
A slow, steady rise in average fuel prices can be expected over the next ten years. Seasonal influences and periodic swings in market psychology will tend to cause both upward and downward price "spikes" during this period. However, surplus availability and competition among fuels will act to keep fuel prices moderate relative to the runaway price levels experienced during the 1970s and early 1980s.

Natural gas price rises will be constrained by the continuing displacement of natural gas as a boiler fuel, although this may be offset somewhat by additional demand for natural gas attributable to load growth and as a consequence of new Clean Air legislation. Natural gas prices are also affected by the ceiling imposed by the price of residual fuel oil, a substitute fuel. Occasionally, world events may cause oil prices to soar, which may in turn allow natural gas prices to increase to abnormally high levels during peak consumption periods. During the remainder of the year, however, natural gas prices should be relatively soft because of the expected continuation of competition among gas suppliers.

Coal prices can be expected to rise during the next ten years. Mining costs and rail transportation costs are expected to increase slowly. The over-supply of western coal will continue to moderate solid fuel prices. As existing contracts expire, coal requirements will be satisfied through either spot market arrangements or market price-based, firm-commitment contracts.

Lignite prices are expected to increase at a rate roughly equal to the rate of inflation. Since lignite-fired power plants are typically mine-mouth operations, lignite prices will vary with mining costs; transportation will have only a small effect on the delivered price

FIGURE 2.1
FUEL REQUIREMENTS FOR ELECTRICITY GENERATION
BY UTILITIES IN TEXAS



Note: Only Texas-supplied generation included.

Factors affecting the price of nuclear fuel are: 1) an abundance of low-cost uranium, 2) a strong secondary market for material and services, and 3) low demand due to high inventory levels, existing contract commitments, and limited growth in nuclear generation. During the next ten years, the uranium market is expected to become more efficient and competitive, although at reduced levels of production compared to the early 1980s. Utilities will have stabilized their nuclear materials and services inventories and contract terms will reflect a buyer's market.

Nuclear fuel is projected to be the least expensive fuel during the next ten years. The average price of nuclear fuel is projected to be approximately seventy cents per million BTU compared to lignite at $1.95 per million BTU, coal at $2.60 per million BTU, and gas at $3.60 per million BTU by the year 2000.

Fuel Price Projections

Tables 2.14 through 2.17 present the Commission staff projection of fuel prices for 1990 through 2000. The prices given in Tables 2.14 through 2.17 are projections based on existing fuel supply contracts, projected spot fuel prices, and each utility's ability to negotiate effectively in the marketplace. Utility-furnished information related to existing contracts was analyzed, and costs for fuel to be taken through existing contracts were projected. Costs of fuel to be bought through spot market or new contracts were projected by the staff based upon expectations of future market conditions for each fuel.

The current natural gas mix in Texas consists of approximately 50 percent obtained under firm contract and 50 percent obtained on the spot market. By the year 2000, the mix should reflect a greater reliance on firm contracts. However, future firm supply contracts will be market-responsive. Prices will be tied to a market representative index, or the contracts will contain periodic reopeners so that either the buyer or seller can make adjustments for unforeseen market events. Generally, market presence will be a key price determinant. Larger consumers such as HL&P, GSU, and CPL should be able to exert more buying leverage in the marketplace relative to smaller users such as WTU, SPS, and EPE.

TABLE 2.14

STAFF-PROJECTED AVERAGE NATURAL GAS PRICES
($/MMBTU)

Year	COA	CPS	CPL	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	TU	WTU	BEPC
1989	1.89	1.89	2.28	1.93	1.88	1.85	1.81	2.05	2.29	2.55	2.26	1.85
1990	2.10	1.94	2.39	2.02	1.95	1.94	1.81	2.14	2.01	2.54	2.39	1.89
1991	2.16	1.98	2.47	2.14	2.07	2.06	1.87	2.27	1.99	2.66	2.56	2.01
1992	2.22	2.11	2.35	2.18	2.18	2.16	1.96	2.38	2.11	2.78	2.69	2.09
1993	2.23	2.24	2.23	2.28	2.30	2.28	2.10	2.50	2.23	2.89	2.84	2.19
1994	2.37	2.37	2.36	2.42	2.45	2.41	2.25	2.64	2.37	3.09	3.02	2.32
1995	2.51	2.51	2.45	2.59	2.59	2.57	2.39	2.80	2.51	3.18	3.23	2.47
1996	2.66	2.66	2.60	2.79	2.77	2.75	2.55	2.99	2.66	3.36	3.42	2.63
1997	2.82	2.82	2.78	3.00	2.96	2.96	2.71	3.17	2.84	3.48	3.64	2.78
1998	3.00	3.00	2.96	3.23	3.16	3.16	2.90	3.37	3.03	3.64	3.89	2.96
1999	3.19	3.19	3.15	3.47	3.37	3.36	3.08	3.58	3.24	3.76	4.14	3.14
2000	3.38	3.38	3.35	3.76	3.60	3.59	3.29	3.82	3.45	3.85	4.42	3.35

TABLE 2.15

STAFF-PROJECTED AVERAGE DELIVERED COAL PRICES
($/MMBTU)

Year	COA	CPS	CPL	EPE	GSU	HL&P	LCRA	SPS	SWEPCO	WTU
1989	---	1.31	2.26	1.01	1.84	2.32	1.34	1.64	1.98	1.80
1990	1.15	1.28	2.34	1.01	1.86	2.39	1.15	1.68	2.01	1.86
1991	1.21	1.34	2.42	1.07	1.97	2.47	1.21	1.76	2.12	1.92
1992	1.24	1.36	2.50	1.12	2.09	2.56	1.24	1.86	2.25	1.99
1993	1.29	1.42	2.61	1.18	2.16	2.68	1.29	1.89	2.32	2.07
1994	1.33	1.48	2.72	1.24	2.26	2.79	1.33	1.98	2.44	2.16
1995	1.45	1.55	2.45	1.30	2.38	2.92	1.45	2.08	2.57	2.25
1996	1.51	1.65	2.58	1.37	2.31	3.06	1.51	2.17	2.67	2.36
1997	1.64	1.74	2.70	1.44	2.39	3.21	1.64	2.26	2.77	2.47
1998	2.01	1.84	2.82	1.52	2.47	3.36	1.72	2.35	2.87	2.59
1999	2.10	1.96	2.93	1.60	2.55	3.53	1.82	2.44	2.96	2.71
2000	2.21	2.08	3.05	1.70	2.63	3.72	1.94	2.55	3.07	2.86

TABLE 2.16

STAFF-PROJECTED AVERAGE LIGNITE PRICES
($/MMBTU)

Year	TU	HLP	SWEPCO	TNP	TMPA	SMEC
1989	0.89	1.45	1.26	---	1.22	0.80
1990	0.93	1.51	1.31	1.38	1.27	0.84
1991	0.96	1.56	1.36	1.49	1.32	0.87
1992	1.00	1.63	1.41	1.63	1.38	0.90
1993	1.05	1.71	1.48	1.72	1.44	0.95
1994	1.10	1.79	1.55	1.83	1.51	0.99
1995	1.14	1.87	1.63	1.94	1.58	1.04
1996	1.18	1.82	1.71	2.06	1.67	1.09
1997	1.24	1.91	1.80	2.19	1.75	1.15
1998	1.30	1.93	1.90	2.32	1.85	1.21
1999	1.37	2.03	2.00	2.46	1.95	1.28
2000	1.45	2.14	2.11	2.61	2.05	1.35

TABLE 2.17

STAFF-PROJECTED AVERAGE NUCLEAR FUEL PRICES
($/MMBTU)

Year	COA	CPS	CPL	EPE	GSU	HLP	TU
1989	0.45	0.45	0.52	1.00	1.26	0.54	---
1990	0.46	0.46	0.52	0.84	1.06	0.54	0.44
1991	0.48	0.48	0.55	0.83	1.04	0.55	0.56
1992	0.51	0.51	0.56	0.80	0.98	0.56	0.57
1993	0.51	0.51	0.58	0.73	0.91	0.58	0.58
1994	0.51	0.51	0.59	0.68	0.85	0.59	0.55
1995	0.51	0.51	0.60	0.66	0.82	0.60	0.52
1996	0.52	0.52	0.61	0.66	0.79	0.61	0.51
1997	0.54	0.54	0.62	0.67	0.79	0.62	0.51
1998	0.58	0.58	0.64	0.71	0.83	0.64	0.51
1999	0.64	0.64	0.66	0.74	0.83	0.66	0.52
2000	0.68	0.68	0.70	0.78	0.87	0.70	0.52

Although delivered spot coal prices will be mostly dependent on coal supply and demand factors and rail distances from the Powder River Basin or other coal supply areas, contract coal prices will be governed primarily by existing coal and rail transportation contracts. Many of the existing coal supply agreements were consummated in the sellers' market of the mid-1970s to early 1980s, and the resulting delivered costs may not reflect current market conditions. A combination of long rail transportation distances and 1970s vintage coal contracts will likely keep delivered coal costs to HL&P, WTU, SWEPCO, CPL, and GSU high over the forecast period. Interestingly, the non-investor-owned generating utilities, as a group, have been more successful in minimizing problems associated with seller's market coal contracts than the investor-owned companies. COA, CPS, and LCRA generally have lower projected coal costs for the period than the investor-owned companies.

Supply of all lignite requirements for existing stations is virtually guaranteed through long-term contracts. The prices under these contracts are expected to increase at about the rate of overall inflation during the ten-year forecast period. TU Electric was the first Texas utility to develop lignite on a large scale, and its reserves are among the best in the state. SWEPCO also participated in some early lignite reserve acquisition, and the two SWEPCO properties which are currently in production are among the better lignite deposits in the Gulf Coast area.

Projected nuclear fuel costs depend on the arrangements which govern each utility's nuclear fuel supply. Differences in nuclear fuel prices reflect different material and services contracts, different inventory levels and carrying costs, and different methods of financing nuclear fuel. Nuclear fuel prices converge in the later years of the forecast. This convergence reflects a stabilization of inventory levels in conjunction with supplies more closely matched with market conditions. Material and services supply contracts will expire and should be replaceable by contracts better suited to satisfy the needs of the mature nuclear plant.

Future Fuel Availability

Natural Gas. Major disruptions of natural gas supplies are not expected during the next ten years. Price increases and the resulting increase in exploration activity during the late 1970s and early 1980s has created a natural gas oversupply, the gas "bubble", which persists today. The effect of natural gas oversupply is depressed prices, so reserve additions have not been replacing production. Eventually, supply and demand will come back into balance, and gas prices will rise. Increased prices will again generate increased exploration activity but at the same time curtail demand. Consequently, although there may be periods of sharply rising prices driven by tightening supply, these periods will be followed by falling prices as reduced demand meets increased supply.

Current gas supplies are adequate for projected generation requirements and prices are relatively stable. However, the long-term uncertainties associated with both price and supplies of natural gas likely will prevent utilities from planning any new baseload gas-fired generation. A recent Department of Energy study concluded that substantial quantities of natural gas that could be developed profitably at prices below $3.00 per million BTU are yet to be discovered in the United States[2].

An example of the uncertainty in predicting price and supply can be viewed in Figure 2.2. This figure compares the annual forecasts of the price of natural gas to electric utilities in the U.S. West South Central Region. These forecasts were prepared by DRI/McGraw-Hill, a large energy forecasting group. One can see that DRI's forecasted trends have resulted in the actual prices for natural gas being significantly overestimated. The 1980 DRI projection of the 1990 price is six times the actual price. Its 1984 projection for 1990 is nearly twice the actual 1990 price. In 1988, DRI's projected 1990 price is seven percent too high. Short-term projections are less effected by high escalation rates, but the long-term effects of compounded high rates quickly yield a divergence of projections from actual prices. In reality, the market has not allowed the price of natural gas to escalate at the rates that DRI has predicted.

Coal. Almost all coal-fired generating units that serve Texas are fueled with sub-bituminous coal, purchased from the Powder River Basin in Wyoming, and other western U. S. bituminous and subbituminous coal. Presently, the Powder River Basin, as well as the U. S. coal industry in general, has excess production capacity and projected demand is not likely to employ the extra deliverability for several years. New coal supply arrangements will continue to be market price-based until the excess production capacity is eliminated sometime beyond the ten-year forecast period.

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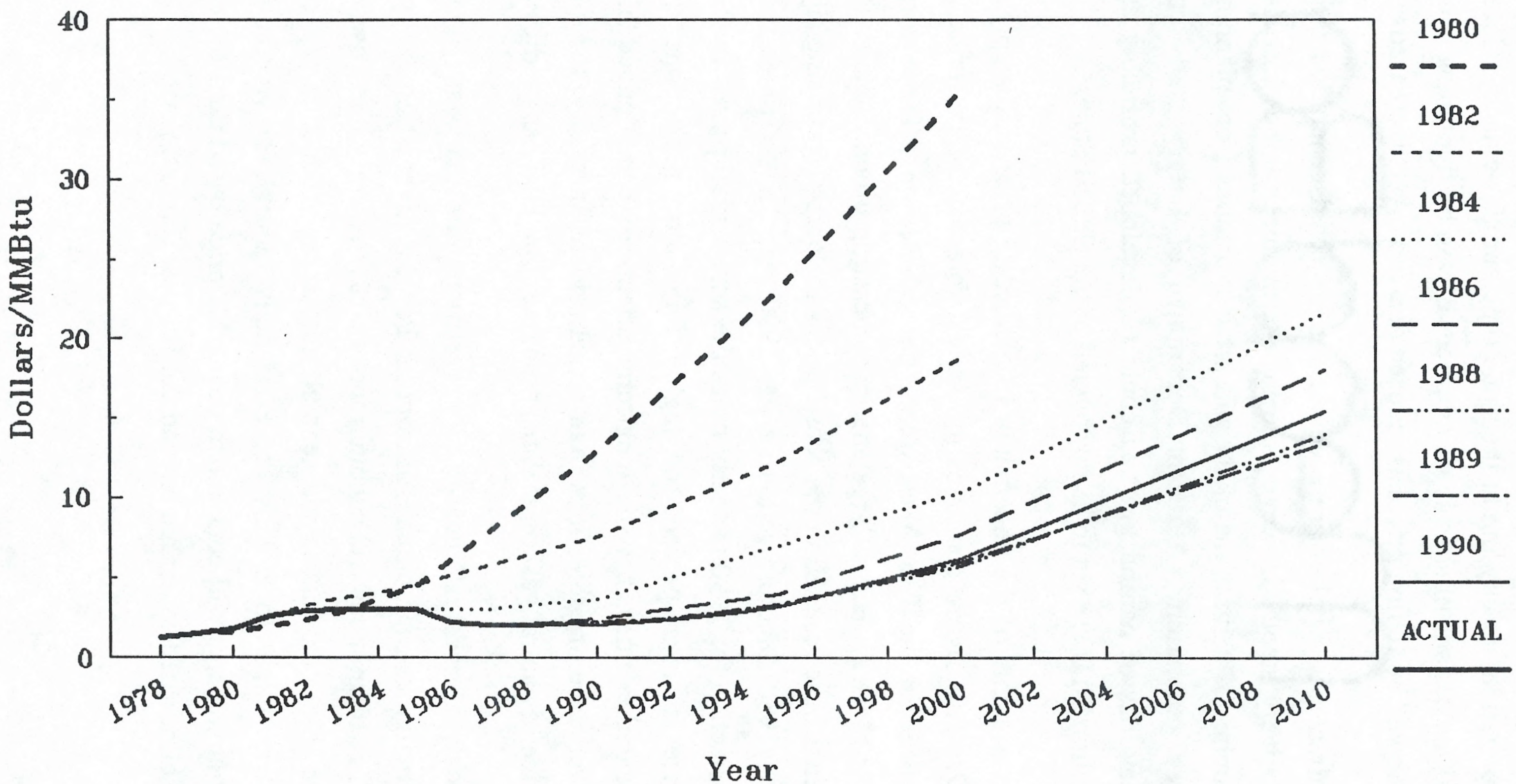
2 Department of Energy, An Assessment of the Natural Gas Resource Base of the United States. Washington D.C., 1988

FIGURE 2.2
PRICE OF NATURAL GAS TO ELECTRIC UTILITIES



DRI/McGraw Hill, Energy Review, Winter,
various issues
West South Central Region

Lignite. As previously noted, the lignite required for the next ten years is already under contract, dedicated to serving an adjacent power plant. Two events could adversely affect the otherwise firm plans for lignite consumption. The first detrimental event which could affect an individual plant would be a major mining stoppage caused by a major equipment failure, mine failure, or labor strike. The other event which could adversely affect lignite consumption would be a change of regulations covering the burning of lignite.

Although lignite is a primary fuel planned for future capacity expansion in Texas, the low price of western coal may displace some planned lignite-fired generation for economic reasons.

Nuclear. The manner in which nuclear fuel is consumed precludes any short-term availability difficulties. The critical path for nuclear fuel is the manufacturing of the fuel bundles. Because the manufacturing process involves five distinct steps which are performed at different locations, fuel unavailability can be caused by inadequate planning or an unavailability of material (yellowcake, natural uranium hexafluoride, or enriched uranium hexafluoride) or services (conversion, enrichment, or fabrication).

In the current market, yellowcake is both plentiful and inexpensive. Many suppliers are available to satisfy demand for yellowcake, including several reliable foreign suppliers. Yellowcake is plentiful in the secondary market as well. The development of several high quality uranium deposits and large utility inventories of yellowcake are likely to keep uranium prices low for the next several years.

Strong competitive secondary markets also exist for natural uranium hexafluoride, conversion services, and enrichment services. The availability of enrichment services is particularly good because of the strong secondary market as well as services offered by foreign suppliers.

The area which shows the highest risk from a disruption of supply is the fabrication service sector. Only a few suppliers offer fabrication services and any loss of service from a supplier will likely mean a disruption to the nuclear fuel supply. Although the consequences of disruption of fabrication services is high, the probability of such a disruption is low.

<u>CHAPTER THREE</u>

ELECTRICITY DEMAND FORECAST

Chapter Three provides the Commission staff's recommended demand projections from 1990 through 2000 for 13 of the state's largest generating electric utilities.[1] Following a discussion of the PUCT staff's modeling efforts developing the projections, details of staff-recommended projections are given and contrasted with the utility-provided forecasts of total sales and peak demand. The chapter closes with a brief discussion on forecast accuracy.

Electricity Demand Forecasting Projects at the PUCT

Over the past seven years, the Economic Analysis Section of the Public Utility Commission of Texas has initiated three distinct projects designed to produce accurate, flexible, and tenable independent projections of demand to be faced by the largest generating electric utilities in Texas. These projects are: the Econometric Electricity Demand Forecasting System; the End-Use Energy Modeling and Forecasting System; and the State Space, Time Series, and Bayesian Forecasting.[2]

Methods Used in This Report

The **Econometric Electricity Demand Forecasting System** project statistically estimates the relationships between electricity demand and various demand determinants or "explanatory variables." These demand determinants include weather, population, personal income, electricity prices, and prices of alternative energy sources. Future electricity consumption is projected based on the historical relationships and forecasts of the demand determinants. The electricity sales projections are converted to peak demand

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1 The "10-year" forecast and resource plan discussed throughout this report actually covers the period 1990 to 2000 (or 11 years, inclusive). The eleventh year is included to facilitate comparisons with other reports and projections, many of which refer to the year 2000.

2 Partial funding for the Commission's End-Use Modeling Project was secured through the Governor's Energy Office and the State Energy Conservation Program.

using the Hourly Electric Load Model (HELM). Simultaneous-equation econometric models have been developed for the major electric utilities in the state. Numerous improvements have been made to this forecasting system since its inception in 1984.

For this report, the Econometric Electricity Demand Forecasting System is primarily relied upon to derive the long-term peak demand projections that form the basis for the evaluation of capacity requirements described later in this volume. The current structure of this modeling system is described in Volume III.

The **End-Use Energy Modeling and Forecasting System** Project, initiated in the spring of 1985, examines the final uses of energy in Texas. These end-uses include: air conditioning, space heating, refrigeration, lighting, irrigation, and industrial processes. Changes in the stock of energy-intensive equipment, appliance efficiencies, usage patterns, and the determinants of these factors (demographic patterns, technology, laws, regulations, fuel prices, etc.) are addressed. End-use models provide a means of estimating the technical and economic potential of a variety of conservation and load management strategies. In addition, the forecasts derived from end-use modeling systems provide a validity check on the results obtained from econometric forecasting models. The third and final phase of this project was completed in June 1990.

While the Econometric and End-use Energy models are designed to provide an accurate long-range outlook for the state's electricity service areas, the **State Space and Time Series** models are employed to provide short-term projections of peak demand. These models examine patterns in a given utility's quarterly peak demand over time. Seasonal, cyclical, and trend components of historical patterns are identified, and projections are developed based on the delineation of these components.

Pursuing three distinct forecasting methods permits the Commission staff to exploit the unique capabilities of each. Econometric models are typically more useful in the study of the responsiveness of electricity demand to energy prices and the impact of weather and economic activity on energy demand. End-use models are considered superior with regard to estimating conservation and load management program impacts. Recent studies in the statistical and econometric literature affirm the accuracy and applicability of time series models in short-term to medium-range peak demand forecasting applications. The results of each of these forecasting methods provide validity checks of the projections developed from alternative staff approaches, as well as the projections of the utility-provided forecasts.

The Commission staff's projections are intended to provide a reasonable estimate of the future demand to be faced by the largest electricity producers in Texas, given the most updated and reliable information available at the Commission.

Public Utility Commission Staff-Recommended Peak Demand Forecasts

The staff-recommended demand projections for the 13 largest generating electric utilities are contrasted with utility-developed forecasts of total sales and peak demand. The projections of peak demand and sales presented here are net of all adjustments that reflect the effects of demand-side resources. Three types of demand-side impacts which are estimated and used to adjust the "raw" peak demand and sales forecasts are:

1. Exogenous factors
2. Active demand-side management
3. Passive demand-side management

Exogenous factor adjustments include the effects of laws and customer actions beyond the control of the utility. Active and passive demand-side management (DSM) adjustments include the effects of programs not reflected in the "raw" econometric forecasts. (See Chapter 5 for a detailed discussion of these adjustments.)

Independent peak demand and sales projections have been developed by the staff for the following utilities (refer to Tables 3.1 through 3.51):

Utility Name	Acronym
Texas Utilities Electric Company	TU Electric
Houston Lighting and Power Company	HL&P
Gulf States Utilities Company	GSU
Central Power and Light Company	CPL
City Public Service of San Antonio	CPS
Southwestern Public Service Company	SPS
Southwestern Electric Power Company	SWEPCO
Lower Colorado River Authority	LCRA
City of Austin	COA
West Texas Utilities Company	WTU
El Paso Electric Company	EPE
Texas-New Mexico Power Company	TNP
Brazos Electric Power Cooperative	BEPC

Note that peak demand and sales figures are projections from 1990.

The statewide coincident peak demand forecast is presented in Table 6.19. The corresponding statewide sales forecast is presented in Appendix B, Table B.1.

TU Electric Company The system peak demand faced by the largest electric utility in Texas is expected to approximate 22,000 MW by the year 2000. This represents a 2.38 percent annual increase in peak load over the next eleven years. The Company's peak demand grew at a much faster rate between the years 1975 and 1985, propelled by an increase in oil prices and an influx of jobs and people to the region. In 1986, a precipitous drop in oil prices was a leading cause of the contraction of the economy in TU Electric's service area. The region's economy is expected to recover and remain stable through the end of the century with population and labor growth rates of approximately 1.5 and 1.9 percent, respectively.

Total system sales are projected to grow by 2.55 percent annually over the next decade. Residential sales are forecasted to grow at 2.71 percent, followed by industrial sales at 2.49 percent. Commercial sales are anticipated to be the slowest at 2.41 percent.

Houston Lighting and Power Company HL&P is expected to experience annual growth in peak demand of 2.52 percent over the next decade, after adjustments for self-generation and demand-side management programs, including interruptible load. Total adjusted system sales are projected to grow at an average annual rate of 2.16 percent through the year 2000. Residential sales are forecasted to grow at an annual rate of 2.78 percent and commercial sales are forecasted to grow at 3.32 percent. Growth in industrial sales is expected to be lower than in residential and commercial sales at 1.29 percent.

The Houston area was especially affected by the state's economic downturn. Between 1976 and 1986, the region sustained two economic booms and recessions. In particular, the 1986 collapse in oil prices resulted in unemployment levels above 10 percent. However, in the last four years the HL&P service area has made a strong recovery with growth in the trade and petrochemical sectors. Non-agricultural employment is anticipated to increase at an annual rate of 2.3 percent through 1999, the strongest employment outlook in the state.

Other sales by HL&P are made primarily to Texas-New Mexico Power Company for resale. However a reduction in load is expected with the commercial operation of each unit of TNP One, TNP's first source of internal generation in this state.

TABLE 3.1
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
TEXAS UTILITIES ELECTRIC COMPANY

Year	Staff Adjusted (MW)	TU Electric Adjusted (MW)	Difference (MW)	Difference (%)
1989	16,944	16,944		
1990	17,401	17,685	-284	-1.61%
1991	17,551	18,140	-589	-3.25%
1992	17,874	18,562	-688	-3.71%
1993	18,428	18,888	-460	-2.44%
1994	18,771	19,213	-442	-2.30%
1995	19,281	19,614	-333	-1.70%
1996	19,796	20,059	-263	-1.31%
1997	20,317	20,502	-185	-0.90%
1998	20,814	20,966	-152	-0.72%
1999	21,321	21,440	-119	-0.56%
2000	21,945	21,930	15	0.07%
Avg. Annual Growth Rates 1989-2000	2.38%	2.37%		

TABLE 3.2
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
TEXAS UTILITIES ELECTRIC COMPANY

Year	Staff Total Adjusted (MWH)	TU Electric Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	81,720,696	81,720,696		
1990	82,180,863	82,863,950	-683,087	-0.82%
1991	83,222,398	85,214,016	-1,991,618	-2.34%
1992	84,984,609	87,516,606	-2,531,997	-2.89%
1993	87,907,971	89,572,572	-1,664,601	-1.86%
1994	89,886,752	91,552,919	-1,666,167	-1.82%
1995	92,789,431	93,883,593	-1,094,162	-1.17%
1996	95,749,626	96,476,088	-726,462	-0.75%
1997	98,746,907	98,979,941	-233,034	-0.24%
1998	101,669,375	101,774,044	-104,669	-0.10%
1999	104,518,711	104,450,353	68,358	0.07%
2000	107,812,303	107,179,643	632,660	0.59%
Avg. Annual Growth Rates 1989-2000	2.55%	2.50%		

TABLE 3.3
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
TEXAS UTILITIES ELECTRIC COMPANY

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	27,204,857	23,836,336	22,163,404	8,516,099	81,720,696
1990	27,965,135	22,954,990	22,591,433	8,669,305	82,180,863
1991	28,610,575	23,224,008	22,543,000	8,844,815	83,222,398
1992	29,370,422	23,774,977	22,776,602	9,062,609	84,984,609
1993	30,329,821	24,837,618	23,405,121	9,335,412	87,907,971
1994	30,996,287	25,570,096	23,774,614	9,545,756	89,886,752
1995	31,861,007	26,486,179	24,594,925	9,847,321	92,789,431
1996	32,732,827	27,383,900	25,484,967	10,147,932	95,749,626
1997	33,594,089	28,359,312	26,368,249	10,425,257	98,746,907
1998	34,427,044	29,231,841	27,291,295	10,719,195	101,669,375
1999	35,307,085	30,075,266	28,152,803	10,983,558	104,518,711
2000	36,507,802	30,961,866	29,058,371	11,284,264	107,812,303
Avg. Annual Growth Rates 1989-2000	2.71%	2.41%	2.49%	2.59%	2.55%

FIGURE 3.1
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
TEXAS UTILITIES ELECTRIC COMPANY

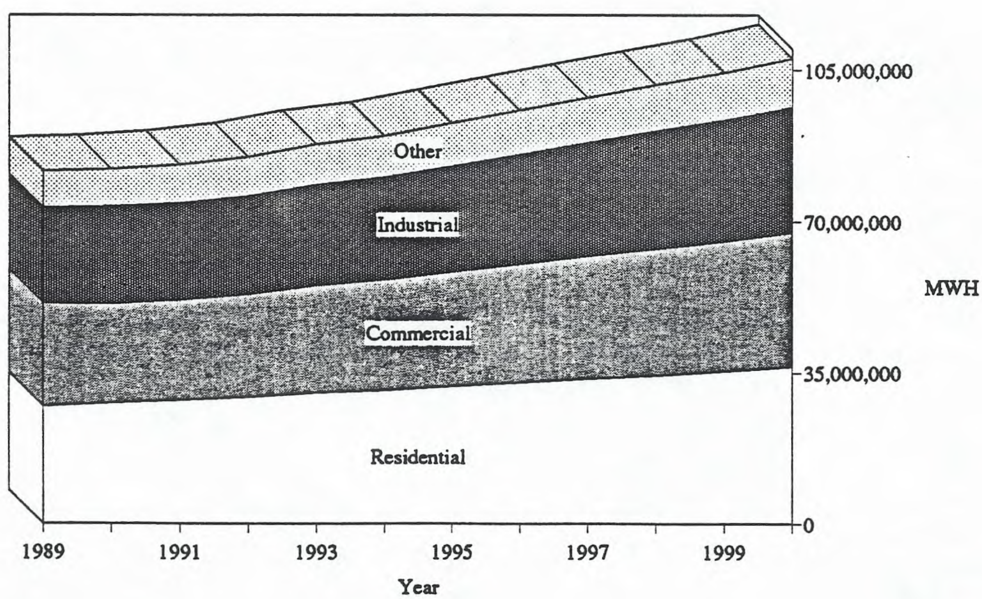


TABLE 3.4
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
HOUSTON LIGHTING AND POWER COMPANY

Year	Staff Adjusted (MW)	HL&P Adjusted (MW)	Difference (MW)	Difference (%)
1989	10,456	10,456		
1990	10,688	10,735	-47	-0.44%
1991	11,045	10,870	175	1.61%
1992	11,221	11,077	144	1.30%
1993	11,271	11,272	-1	-0.01%
1994	11,480	11,483	-3	-0.02%
1995	11,804	11,655	149	1.28%
1996	12,129	11,937	192	1.61%
1997	12,509	12,165	344	2.83%
1998	12,863	12,382	481	3.88%
1999	13,309	12,716	593	4.66%
2000	13,754	13,065	689	5.27%
Avg. Annual Growth Rates 1989-2000	2.52%	2.05%		

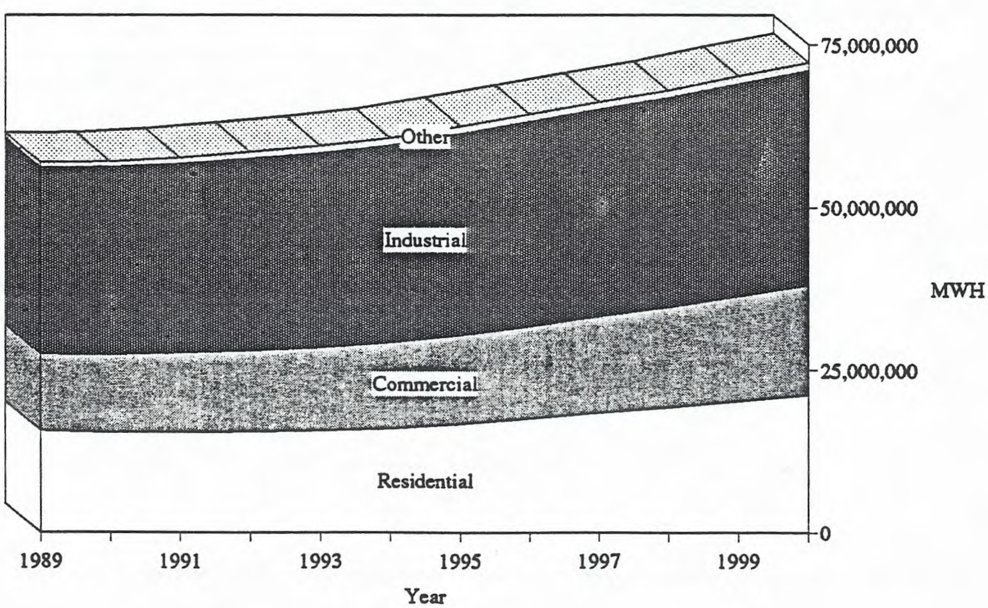
TABLE 3.5
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
HOUSTON LIGHTING AND POWER COMPANY

Year	Staff Total Adjusted (MWH)	HL&P Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	56,959,602	56,959,602		
1990	57,018,361	55,591,671	1,426,690	2.57%
1991	57,593,034	57,646,389	-53,355	-0.09%
1992	58,535,957	60,424,790	-1,888,833	-3.13%
1993	59,438,888	62,261,185	-2,822,297	-4.53%
1994	60,672,319	62,467,399	-1,795,080	-2.87%
1995	62,435,738	63,037,957	-602,219	-0.96%
1996	64,317,789	64,601,776	-283,987	-0.44%
1997	66,188,965	66,209,330	-20,365	-0.03%
1998	67,981,113	67,427,942	553,171	0.82%
1999	70,177,545	69,274,948	902,597	1.30%
2000	72,260,608	71,347,130	913,478	1.28%
Avg. Annual Growth Rates 1989-2000	2.19%	2.07%		

TABLE 3.6
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
HOUSTON LIGHTING AND POWER COMPANY

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	15,699,502	11,775,557	28,689,553	794,990	56,959,602
1990	15,445,634	11,962,700	28,873,596	736,431	57,018,361
1991	15,439,932	12,194,049	29,135,148	823,905	57,593,034
1992	15,489,836	12,483,062	29,565,952	997,107	58,535,957
1993	15,660,357	12,808,479	29,956,196	1,013,856	59,438,888
1994	16,023,872	13,176,890	30,440,982	1,030,575	60,672,319
1995	16,669,894	13,636,435	31,082,136	1,047,272	62,435,738
1996	17,534,985	14,195,764	31,523,096	1,063,943	64,317,789
1997	18,442,769	14,814,490	31,851,114	1,080,592	66,188,965
1998	19,246,567	15,450,209	32,187,118	1,097,220	67,981,113
1999	20,221,026	16,139,101	32,703,592	1,113,826	70,177,545
2000	21,216,676	16,873,540	33,039,980	1,130,412	72,260,608
Avg. Annual Growth Rates 1989-2000	2.78%	3.32%	1.29%	3.25%	2.19%

FIGURE 3.2
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
HOUSTON LIGHTING AND POWER COMPANY



Gulf States Utilities Company Peak demand in the GSU Texas service area is expected to reach approximately 2,475 MW by the year 2000. GSU's total system peak demand is projected to reach nearly 5,620 MW over the forecast period. This translates into annual growth rates of 1.09 and 1.12 percent, respectively.

This relatively low growth reflects the depressed state of the service area economies. GSU serves an area extending 350 miles westward from Baton Rouge, Louisiana to a point about 50 miles east of Austin, Texas. This area was particularly hard hit by the drop in oil prices in 1986. Future recovery, if only moderate in nature, will fail to bolster the demand for electricity.

The relatively depressed economic conditions in the GSU service area are also reflected in the staff's sales forecast. Total GSU sales in Texas are expected to grow at an annual rate of 1.08 percent while total system sales are projected to grow at a rate of 1.02 percent. In Texas, industrial sales growth will be most robust at 1.54 percent followed by commercial and residential sales at 1.49 and 1.27 percent, respectively.

Central Power and Light Company CPL, according to the staff's forecast, will experience peak demand of 3,959 MW by the year 2000. Average annual growth in peak demand from 1989 through the year 2000 is expected to be 2.69 percent. This rate is slightly lower than the 2.78 percent growth forecasted by CPL.

Total sales are expected to climb from 15,042,113 MWH in 1989 to 21,477,429 MWH by the year 2000. This yields an average annual growth rate of 3.29 percent. Commercial and Industrial sales are both projected to grow at a rate of approximately 3.8 percent per year through the year 2000. Growth in residential sales is expected to lag behind with a rate of near 2.8 percent.

The three largest cities served by CPL are Corpus Christi, Laredo, and McAllen. Analysts predict relatively strong economic performance in these cities. Corpus Christi will benefit from the completion of several development prospects, while Laredo and McAllen are expected to benefit from the increasing strength of the maquiladora program.

TABLE 3.7
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
GULF STATES UTILITIES COMPANY - TEXAS

Year	Staff Adjusted (MW)	GSU Texas Adjusted (MW)	Difference (MW)	Difference (%)
1989	2,194	2,194		
1990	2,231	2,210	21	0.95%
1991	2,241	2,256	-15	-0.66%
1992	2,197	2,230	-33	-1.48%
1993	2,220	2,268	-48	-2.12%
1994	2,252	2,310	-58	-2.51%
1995	2,288	2,340	-52	-2.22%
1996	2,321	2,375	-54	-2.27%
1997	2,354	2,390	-36	-1.51%
1998	2,385	2,428	-43	-1.77%
1999	2,431	2,459	-28	-1.14%
2000	2,472	2,498	-26	-1.04%
Avg. Annual Growth Rates 1989-2000	1.09%	1.19%		

TABLE 3.8
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
GULF STATES UTILITIES COMPANY - TEXAS

Year	Staff Total Adjusted (MWH)	GSU Texas Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	12,089,744	12,089,744		
1990	12,267,793	12,000,404	267,389	2.23%
1991	12,360,992	12,358,214	2,778	0.02%
1992	12,214,177	12,259,873	-45,696	-0.37%
1993	12,348,405	12,487,521	-139,116	-1.11%
1994	12,516,313	12,711,496	-195,183	-1.54%
1995	12,698,141	12,852,786	-154,645	-1.20%
1996	12,864,885	13,021,667	-156,783	-1.20%
1997	13,034,692	13,240,314	-205,622	-1.55%
1998	13,196,626	13,431,697	-235,071	-1.75%
1999	13,412,925	13,556,725	-143,800	-1.06%
2000	13,610,244	13,763,309	-153,065	-1.11%
Avg. Annual Growth Rates 1989-2000	1.08%	1.19%		

TABLE 3.9
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
GULF STATES UTILITIES COMPANY - TEXAS

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	3,220,486	2,177,647	5,730,475	961,136	12,089,744
1990	3,204,555	2,182,156	6,103,617	777,466	12,267,793
1991	3,214,219	2,187,270	6,167,037	792,465	12,360,992
1992	3,229,414	2,194,598	6,254,575	535,590	12,214,177
1993	3,265,532	2,215,997	6,327,348	539,529	12,348,405
1994	3,322,402	2,249,058	6,401,356	543,498	12,516,313
1995	3,390,184	2,292,486	6,467,976	547,495	12,698,141
1996	3,445,834	2,341,129	6,526,401	551,521	12,864,885
1997	3,495,708	2,393,436	6,589,971	555,578	13,034,692
1998	3,545,423	2,450,224	6,641,314	559,665	13,196,626
1999	3,628,507	2,507,453	6,713,184	563,782	13,412,925
2000	3,701,056	2,561,377	6,779,567	568,245	13,610,244
Avg. Annual Growth Rates 1989-2000	1.27%	1.49%	1.54%	-4.67%	1.08%

FIGURE 3.3
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
GULF STATES UTILITIES COMPANY - TEXAS

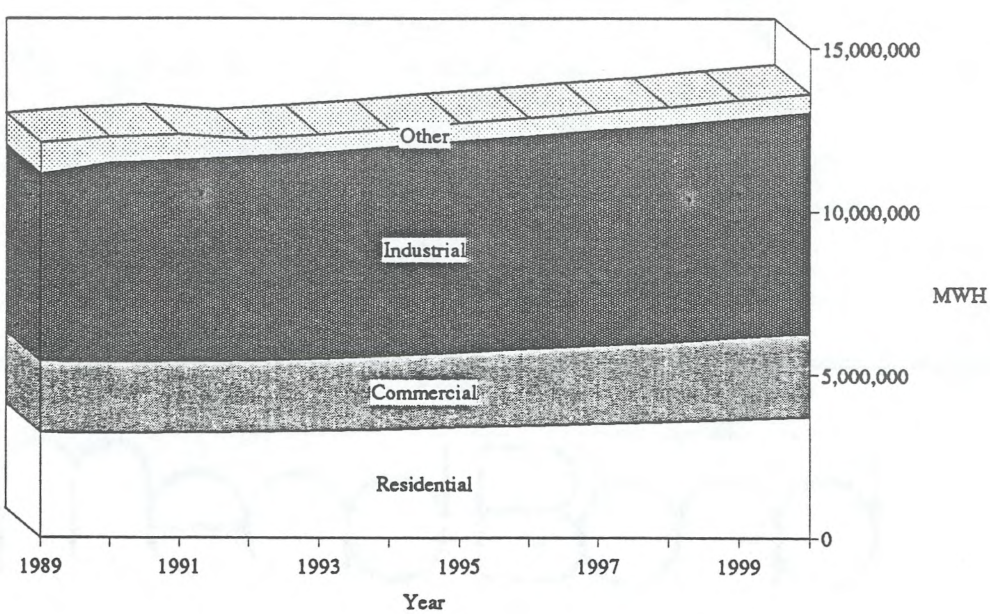


TABLE 3.10
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
GULF STATES UTILITIES COMPANY - TOTAL

Year	Staff Adjusted (MW)	GSU Total Adjusted (MW)	Difference (MW)	Difference (%)
1989	4,970	4,970		
1990	5,025	5,007	18	0.36%
1991	5,076	5,093	-17	-0.33%
1992	5,054	5,108	-54	-1.06%
1993	5,111	5,172	-61	-1.18%
1994	5,192	5,244	-52	-0.99%
1995	5,270	5,310	-40	-0.75%
1996	5,335	5,381	-46	-0.85%
1997	5,399	5,435	-36	-0.66%
1998	5,459	5,504	-45	-0.82%
1999	5,525	5,561	-36	-0.65%
2000	5,616	5,640	-24	-0.43%
Avg. Annual Growth Rates 1989-2000	1.12%	1.16%		

TABLE 3.11
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
GULF STATES UTILITIES COMPANY - TOTAL

Year	Staff Total Adjusted (MWH)	GSU Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	27,466,189	27,466,189		
1990	27,471,999	27,211,916	260,083	0.96%
1991	27,716,604	27,715,481	1,123	0.00%
1992	27,782,968	27,831,605	-48,637	-0.17%
1993	28,118,732	28,236,650	-117,918	-0.42%
1994	28,542,828	28,650,571	-107,743	-0.38%
1995	28,911,718	28,950,134	-38,416	-0.13%
1996	29,234,130	29,281,015	-46,885	-0.16%
1997	29,556,739	29,671,176	-114,437	-0.39%
1998	29,868,620	30,012,324	-143,704	-0.48%
1999	30,245,044	30,306,287	-61,243	-0.20%
2000	30,715,593	30,745,307	-29,714	-0.10%
Avg. Annual Growth Rates 1989-2000	1.02%	1.03%		

TABLE 3.12
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
GULF STATES UTILITIES COMPANY - TOTAL

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	6,473,021	5,197,356	12,332,664	3,463,148	27,466,189
1990	6,437,191	5,180,080	12,701,596	3,153,133	27,471,999
1991	6,455,959	5,219,062	13,444,382	2,597,201	27,716,604
1992	6,506,359	5,269,625	13,657,008	2,349,976	27,782,968
1993	6,567,170	5,343,638	13,848,627	2,359,298	28,118,732
1994	6,697,936	5,435,452	14,041,667	2,367,774	28,542,828
1995	6,830,156	5,543,572	14,155,206	2,382,784	28,911,718
1996	6,922,974	5,660,027	14,256,328	2,394,801	29,234,130
1997	7,014,203	5,782,661	14,356,576	2,403,300	29,556,739
1998	7,084,533	5,912,749	14,452,881	2,418,458	29,868,620
1999	7,199,502	6,043,886	14,569,731	2,431,926	30,245,044
2000	7,323,973	6,169,737	14,776,679	2,445,205	30,715,593
Avg. Annual Growth Rates 1989-2000	1.13%	1.57%	1.66%	-3.11%	1.02%

FIGURE 3.4
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
GULF STATES UTILITIES COMPANY - TOTAL

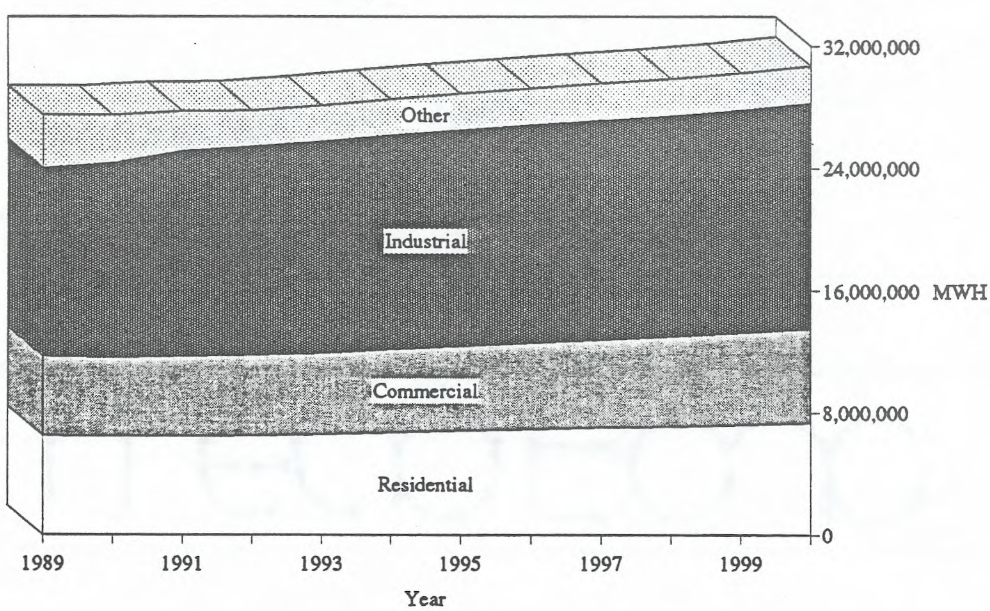


TABLE 3.13
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
CENTRAL POWER AND LIGHT COMPANY

Year	Staff Adjusted (MW)	CPL Adjusted (MW)	Difference (MW)	Difference (%)
1989	2,957	2,957		
1990	2,924	3,132	-208	-6.65%
1991	3,002	3,215	-213	-6.64%
1992	3,107	3,308	-201	-6.08%
1993	3,210	3,358	-148	-4.42%
1994	3,323	3,431	-108	-3.16%
1995	3,433	3,520	-87	-2.48%
1996	3,519	3,613	-94	-2.59%
1997	3,611	3,700	-89	-2.40%
1998	3,716	3,789	-73	-1.94%
1999	3,841	3,897	-56	-1.44%
2000	3,968	3,996	-28	-0.69%
Avg. Annual Growth Rates 1989-2000	2.71%	2.78%		

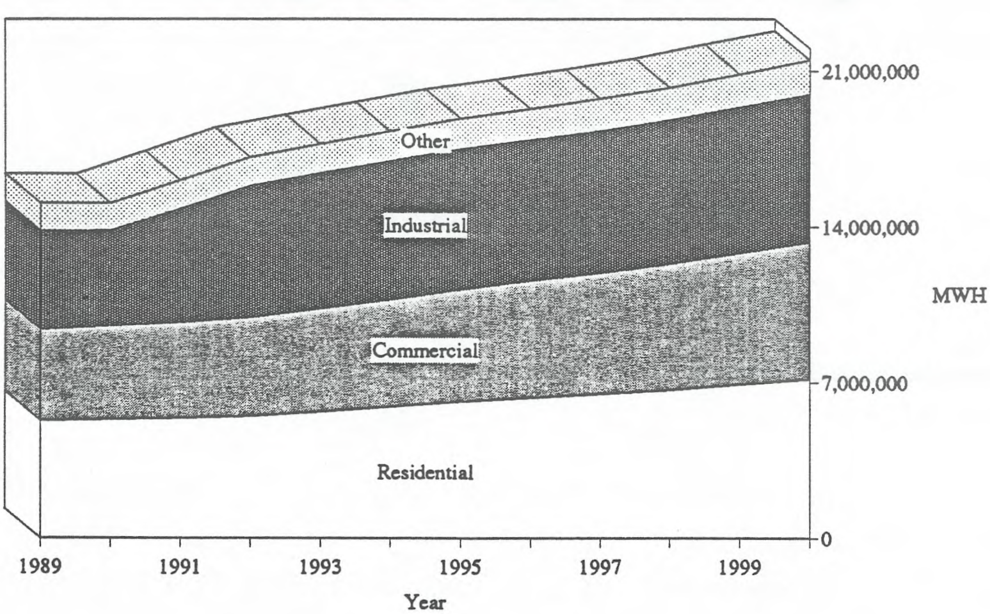
TABLE 3.14
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
CENTRAL POWER AND LIGHT COMPANY

Year	Staff Total Adjusted (MWH)	CPL Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	15,042,113	15,042,113		
1990	15,042,637	15,281,842	-239,205	-1.57%
1991	16,059,900	16,134,146	-74,246	-0.46%
1992	17,118,495	17,223,995	-105,500	-0.61%
1993	17,718,650	17,743,953	-25,303	-0.14%
1994	18,296,814	18,170,556	126,258	0.69%
1995	18,871,537	18,691,290	180,247	0.96%
1996	19,293,512	19,224,105	69,407	0.36%
1997	19,741,291	19,723,491	17,800	0.09%
1998	20,257,740	20,231,561	26,179	0.13%
1999	20,864,865	20,827,959	36,906	0.18%
2000	21,477,429	21,307,633	169,796	0.80%
Avg. Annual Growth Rates 1989-2000	3.29%	3.22%		

TABLE 3.15
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
CENTRAL POWER AND LIGHT COMPANY

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	5,277,961	4,086,607	4,440,697	1,236,848	15,042,113
1990	5,340,732	4,192,190	4,289,537	1,220,178	15,042,637
1991	5,368,505	4,302,966	5,146,409	1,242,021	16,059,900
1992	5,476,731	4,439,522	5,934,072	1,268,170	17,118,495
1993	5,676,215	4,617,453	6,127,224	1,297,759	17,718,650
1994	5,901,200	4,821,769	6,245,813	1,328,032	18,296,814
1995	6,122,155	5,047,026	6,344,000	1,358,357	18,871,537
1996	6,317,594	5,257,234	6,332,404	1,386,281	19,293,512
1997	6,469,261	5,461,930	6,392,868	1,417,232	19,741,291
1998	6,648,875	5,678,429	6,481,273	1,449,163	20,257,740
1999	6,900,037	5,907,487	6,575,939	1,481,403	20,864,865
2000	7,143,933	6,149,446	6,669,419	1,514,631	21,477,429
Avg. Annual Growth Rates 1989-2000	2.79%	3.78%	3.77%	1.86%	3.29%

FIGURE 3.5
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
CENTRAL POWER AND LIGHT COMPANY



City Public Service Board of San Antonio

San Antonio, served by CPS, has exhibited a recovery equal to if not greater than any of the major markets in Texas. Its recovery has been fueled by growth in the services sector as well as in tourism. The recovery is expected to continue and is reflected in the staff's peak demand and sales forecast.

The staff predicts that peak demand will reach 3,854 MW by the year 2000. This translates into a relatively robust average annual growth rate over the forecast period of 3.30 percent. CPS predicts a growth of 3.90 percent over the same time period.

Total sales are also projected to grow at a relatively strong rate of 3.55 percent per year. Leading the way is industrial sales at 4.33 percent per year followed by commercial sales at 3.71 percent over the forecast period. Residential sales are projected to grow at a rate of 2.68 percent through the year 2000.

Southwestern Public Service Company

Total system peak demand is expected to increase from 2,989 MW in 1989 to 3,367 MW by the year 2000. This yields an annual increase of 1.09 percent. Peak demand in the SPS Texas service area will grow from 2,233 MW in 1989 to 2,449 MW by the year 2000. Annual growth averages 0.84 percent over the forecast period. This is sluggish growth by any standard.

Growth in sales is also expected to be sluggish over the forecast period. Total sales are forecasted to increase at an annual rate of 1.23 percent while sales in Texas are projected to grow at a rate of 1.06 percent. In Texas, commercial sales will be strongest, averaging 1.65 percent over the forecast period. Industrial and residential sales in Texas will bring up the rear averaging 1.34 percent and 1.33 percent, respectively.

Southwestern Electric Power Company

SWEPCO serves customers in portions of Texas, northwestern Louisiana, and western Arkansas. The staff projects an increase of Texas peak demand from 1,407 MW in 1989 to 2,092 MW by the year 2000. This yields a relatively robust annual growth rate of 3.67 percent. Total system peak is expected to grow at an annual rate of 3.26 percent over the forecast period.

Total sales in the Texas service areas is expected to grow at an annual rate of 3.15 percent. Industrial growth is forecasted to be the strongest at 3.25 percent per year followed by residential sales at 2.53 percent and commercial sales at 2.38 percent.

TABLE 3.16
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
CITY PUBLIC SERVICE BOARD OF SAN ANTONIO

Year	Staff Adjusted (MW)	CPS Adjusted (MW)	Difference (MW)	Difference (%)
1989	2,697	2,697		
1990	2,738	2,837	-99	-3.49%
1991	2,841	2,931	-90	-3.07%
1992	2,950	3,026	-76	-2.51%
1993	3,055	3,134	-79	-2.52%
1994	3,157	3,240	-83	-2.56%
1995	3,261	3,361	-100	-2.98%
1996	3,364	3,493	-129	-3.69%
1997	3,472	3,660	-188	-5.14%
1998	3,586	3,830	-244	-6.37%
1999	3,727	3,973	-246	-6.19%
2000	3,854	4,110	-256	-6.23%
Avg. Annual Growth Rates 1989-2000	3.30%	3.90%		

TABLE 3.17
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
CITY PUBLIC SERVICE BOARD OF SAN ANTONIO

Year	Staff Total Adjusted (MWH)	CPS Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	11,648,333	11,648,333	0	0.00%
1990	11,820,444	11,880,833	-60,390	-0.51%
1991	12,271,448	12,345,430	-73,983	-0.60%
1992	12,752,317	12,848,063	-95,747	-0.75%
1993	13,227,995	13,345,793	-117,799	-0.88%
1994	13,701,624	13,865,667	-164,043	-1.18%
1995	14,197,746	14,458,458	-260,712	-1.80%
1996	14,718,421	15,141,257	-422,836	-2.79%
1997	15,257,074	15,902,454	-645,380	-4.06%
1998	15,818,731	16,616,486	-797,755	-4.80%
1999	16,484,420	17,441,303	-956,884	-5.49%
2000	17,103,732	18,201,407	-1,097,676	-6.03%
Avg. Annual Growth Rates 1989-2000	3.55%	4.14%		

TABLE 3.18
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
CITY PUBLIC SERVICE BOARD OF SAN ANTONIO

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	4,684,991	2,373,596	4,300,158	289,588	11,648,333
1990	4,682,787	2,432,219	4,408,446	296,992	11,820,444
1991	4,872,310	2,535,130	4,555,390	308,618	12,271,448
1992	5,054,795	2,660,059	4,716,654	320,809	12,752,317
1993	5,232,868	2,772,203	4,889,312	333,612	13,227,995
1994	5,395,103	2,879,097	5,080,368	347,057	13,701,624
1995	5,535,805	2,992,293	5,308,476	361,172	14,197,746
1996	5,654,620	3,096,426	5,591,375	376,001	14,718,421
1997	5,777,828	3,196,752	5,890,913	391,581	15,257,074
1998	5,919,215	3,301,283	6,190,286	407,947	15,818,731
1999	6,113,936	3,426,917	6,518,413	425,154	16,484,420
2000	6,265,602	3,542,583	6,852,296	443,251	17,103,732
Avg. Annual Growth Rates 1989-2000	2.68%	3.71%	4.33%	3.95%	3.55%

FIGURE 3.6
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
CITY PUBLIC SERVICE BOARD OF SAN ANTONIO

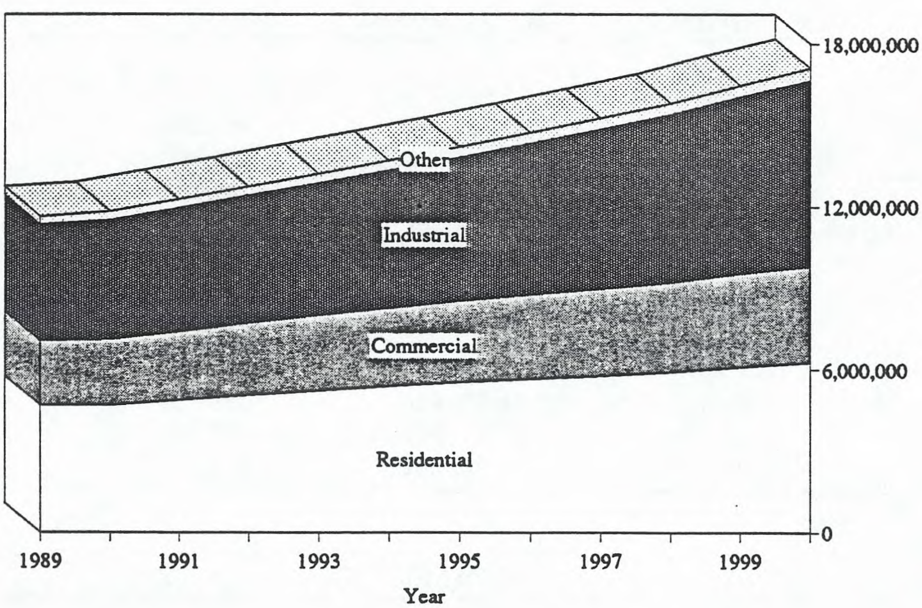


TABLE 3.19
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Staff Adjusted (MW)	SPS Texas Adjusted (MW)	Difference (MW)	Difference (%)
1989	2,233	2,233		
1990	2,157	2,223	-66	-2.98%
1991	2,195	2,251	-56	-2.50%
1992	2,227	2,280	-53	-2.30%
1993	2,257	2,309	-52	-2.24%
1994	2,287	2,339	-52	-2.22%
1995	2,316	2,369	-53	-2.24%
1996	2,344	2,399	-55	-2.31%
1997	2,369	2,430	-61	-2.49%
1998	2,395	2,461	-66	-2.67%
1999	2,422	2,493	-71	-2.85%
2000	2,449	2,522	-72	-2.87%
Avg. Annual Growth Rates 1989-2000	0.84%	1.11%		

TABLE 3.20
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Staff Total Adjusted (MWH)	SPS Texas Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	11,729,501	11,729,501		
1990	11,479,383	11,441,906	37,477	0.33%
1991	11,691,727	11,587,687	104,040	0.90%
1992	11,870,311	11,737,204	133,107	1.13%
1993	12,046,283	11,886,262	160,021	1.35%
1994	12,216,746	12,038,256	178,490	1.48%
1995	12,381,720	12,192,230	189,490	1.55%
1996	12,541,273	12,348,210	193,063	1.56%
1997	12,694,231	12,506,220	188,011	1.50%
1998	12,844,723	12,666,290	178,433	1.41%
1999	12,991,636	12,828,445	163,191	1.27%
2000	13,166,377	12,943,850	222,527	1.72%
Avg. Annual Growth Rates 1989-2000	1.06%	0.90%		

TABLE 3.21
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	1,666,242	1,358,869	5,882,101	2,822,289	11,729,501
1990	1,653,100	1,428,121	5,913,698	2,484,465	11,479,383
1991	1,687,807	1,458,006	6,024,520	2,521,395	11,691,727
1992	1,717,639	1,478,455	6,123,357	2,550,860	11,870,311
1993	1,744,873	1,497,631	6,226,296	2,577,484	12,046,283
1994	1,771,704	1,517,423	6,318,899	2,608,720	12,216,746
1995	1,797,754	1,535,429	6,408,508	2,640,030	12,381,720
1996	1,823,384	1,553,839	6,492,303	2,671,747	12,541,273
1997	1,848,758	1,569,736	6,571,859	2,703,878	12,694,231
1998	1,873,624	1,585,322	6,649,349	2,736,429	12,844,723
1999	1,899,472	1,600,596	6,722,166	2,769,402	12,991,636
2000	1,927,726	1,627,017	6,812,506	2,799,127	13,166,377
Avg. Annual Growth Rates 1989-2000	1.33%	1.65%	1.34%	-0.07%	1.06%

FIGURE 3.7
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

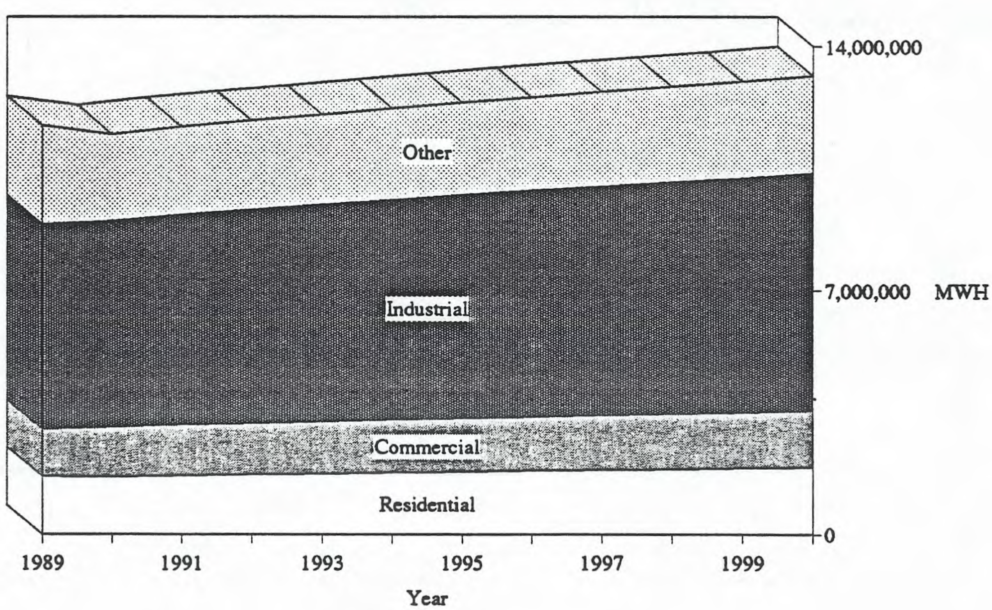


TABLE 3.22
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Staff Adjusted (MW)	SPS Total Adjusted (MW)	Difference (MW)	Difference (%)
1989	2,989	2,989		
1990	2,926	2,998	-72	-2.41%
1991	2,978	3,036	-58	-1.92%
1992	3,021	3,075	-54	-1.74%
1993	3,062	3,115	-53	-1.69%
1994	3,119	3,155	-36	-1.14%
1995	3,190	3,195	-5	-0.16%
1996	3,227	3,236	-9	-0.29%
1997	3,262	3,278	-16	-0.47%
1998	3,296	3,320	-24	-0.72%
1999	3,331	3,363	-32	-0.95%
2000	3,367	3,402	-35	-1.01%
Avg. Annual Growth Rates 1989-2000	1.09%	1.18%		

TABLE 3.23
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Staff Total Adjusted (MWH)	SPS Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	15,669,845	15,669,845		
1990	15,431,956	15,379,359	52,597	0.34%
1991	15,712,838	15,578,400	134,438	0.86%
1992	15,953,871	15,782,040	171,831	1.09%
1993	16,185,411	15,986,285	199,126	1.25%
1994	16,495,488	16,279,197	216,291	1.33%
1995	16,877,492	16,654,777	222,715	1.34%
1996	17,084,091	16,865,101	218,990	1.30%
1997	17,282,083	17,078,153	203,930	1.19%
1998	17,475,825	17,294,040	181,785	1.05%
1999	17,665,189	17,512,745	152,444	0.87%
2000	17,916,409	17,708,557	207,852	1.17%
Avg. Annual Growth Rates 1989-2000	1.23%	1.12%		

TABLE 3.24
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	2,305,986	1,826,945	7,244,626	4,292,288	15,669,845
1990	2,300,966	1,890,468	7,250,417	3,990,106	15,431,956
1991	2,349,688	1,922,564	7,391,651	4,048,935	15,712,838
1992	2,388,130	1,945,985	7,517,185	4,102,571	15,953,871
1993	2,422,359	1,968,204	7,643,560	4,151,289	16,185,411
1994	2,456,518	1,991,064	7,756,736	4,291,170	16,495,488
1995	2,489,207	2,012,142	7,864,404	4,511,740	16,877,492
1996	2,521,401	2,033,628	7,964,052	4,565,010	17,084,091
1997	2,552,974	2,052,602	8,057,525	4,618,983	17,282,083
1998	2,583,653	2,071,264	8,147,231	4,673,677	17,475,825
1999	2,615,706	2,089,616	8,230,772	4,729,096	17,665,189
2000	2,652,844	2,117,876	8,336,486	4,809,203	17,916,409
Avg. Annual Growth Rates 1989-2000	1.28%	1.35%	1.28%	1.04%	1.23%

FIGURE 3.8
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

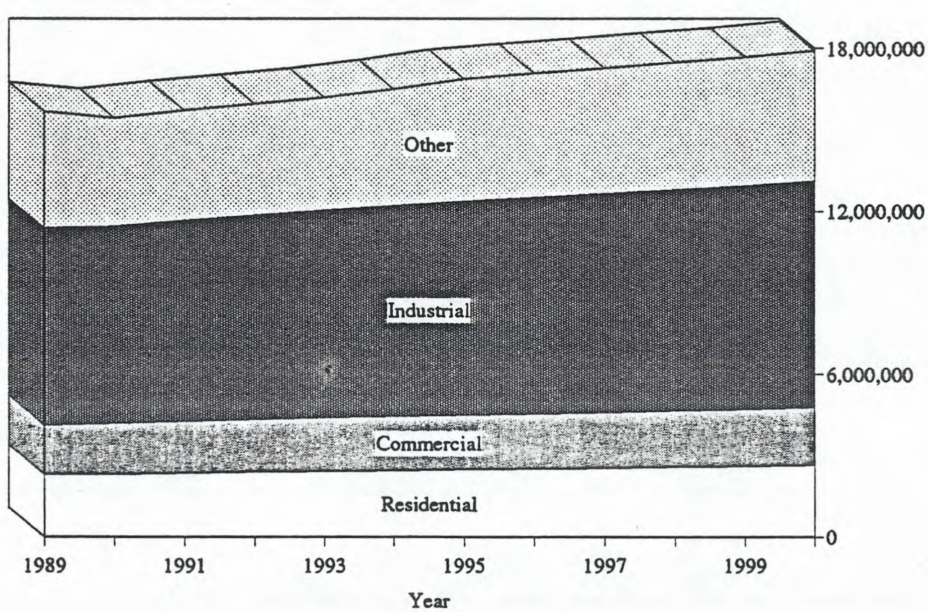


TABLE 3.25
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Staff Adjusted (MW)	SWEPCO Texas Adjusted (MW)	Difference (MW)	Difference (%)
1989	1,407	1,407		
1990	1,485	1,463	22	1.50%
1991	1,536	1,528	8	0.52%
1992	1,582	1,579	3	0.19%
1993	1,638	1,630	8	0.49%
1994	1,701	1,686	15	0.89%
1995	1,766	1,746	20	1.15%
1996	1,830	1,793	37	2.06%
1997	1,894	1,839	55	2.99%
1998	1,959	1,884	75	3.98%
1999	2,028	1,925	103	5.35%
2000	2,092	1,966	126	6.41%
Avg. Annual Growth Rates 1989-2000	3.67%	3.09%		

TABLE 3.26
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Staff Total Adjusted (MWH)	SWEPCO Texas Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	7,541,431	7,541,431		
1990	7,557,152	7,633,498	-76,346	-1.00%
1991	7,812,645	8,179,093	-366,448	-4.48%
1992	8,050,769	8,465,030	-414,261	-4.89%
1993	8,337,295	8,700,176	-362,881	-4.17%
1994	8,658,673	9,021,404	-362,732	-4.02%
1995	8,991,251	9,413,522	-422,271	-4.49%
1996	9,313,997	9,654,085	-340,088	-3.52%
1997	9,635,045	9,891,898	-256,853	-2.60%
1998	9,958,793	10,130,447	-171,654	-1.69%
1999	10,298,399	10,367,630	-69,231	-0.67%
2000	10,611,150	10,578,905	32,245	0.30%
Avg. Annual Growth Rates 1989-2000	3.15%	3.12%		

TABLE 3.27
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	1,445,421	1,176,385	3,119,812	1,799,813	7,541,431
1990	1,443,883	1,131,602	3,166,017	1,815,650	7,557,152
1991	1,435,524	1,158,631	3,253,085	1,965,406	7,812,645
1992	1,452,438	1,192,434	3,355,445	2,050,453	8,050,769
1993	1,498,905	1,231,165	3,478,316	2,128,909	8,337,295
1994	1,555,631	1,274,614	3,617,937	2,210,490	8,658,673
1995	1,618,308	1,316,388	3,761,235	2,295,321	8,991,251
1996	1,674,267	1,357,244	3,898,954	2,383,533	9,313,997
1997	1,725,787	1,398,572	4,035,424	2,475,263	9,635,045
1998	1,775,256	1,441,001	4,171,887	2,570,650	9,958,793
1999	1,841,506	1,482,465	4,304,584	2,669,845	10,298,399
2000	1,902,378	1,523,784	4,437,337	2,747,651	10,611,150
Avg. Annual Growth Rates 1989-2000	2.53%	2.38%	3.25%	3.92%	3.15%

FIGURE 3.9
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

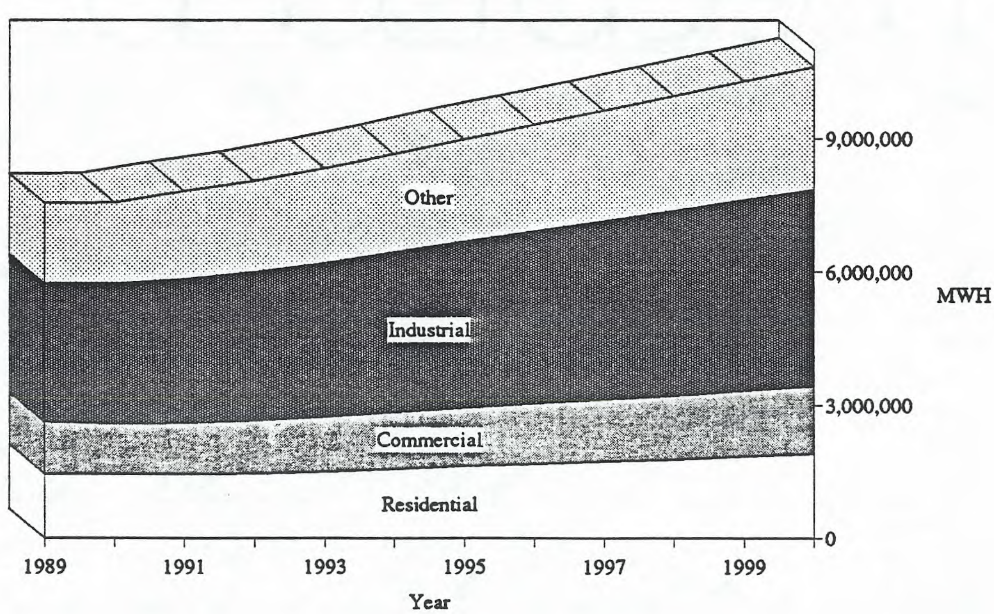


TABLE 3.28
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

Year	Staff Adjusted (MW)	SWEPCO Total Adjusted (MW)	Difference (MW)	Difference (%)
1989	2,812	2,812		
1990	3,017	2,927	90	3.07%
1991	3,062	3,056	6	0.20%
1992	3,141	3,158	-17	-0.54%
1993	3,240	3,261	-21	-0.64%
1994	3,331	3,372	-41	-1.22%
1995	3,422	3,493	-71	-2.03%
1996	3,517	3,587	-70	-1.95%
1997	3,619	3,679	-60	-1.63%
1998	3,737	3,768	-31	-0.82%
1999	3,879	3,850	29	0.75%
2000	4,002	3,932	70	1.78%
Avg. Annual Growth Rates 1989-2000	3.26%	3.09%		

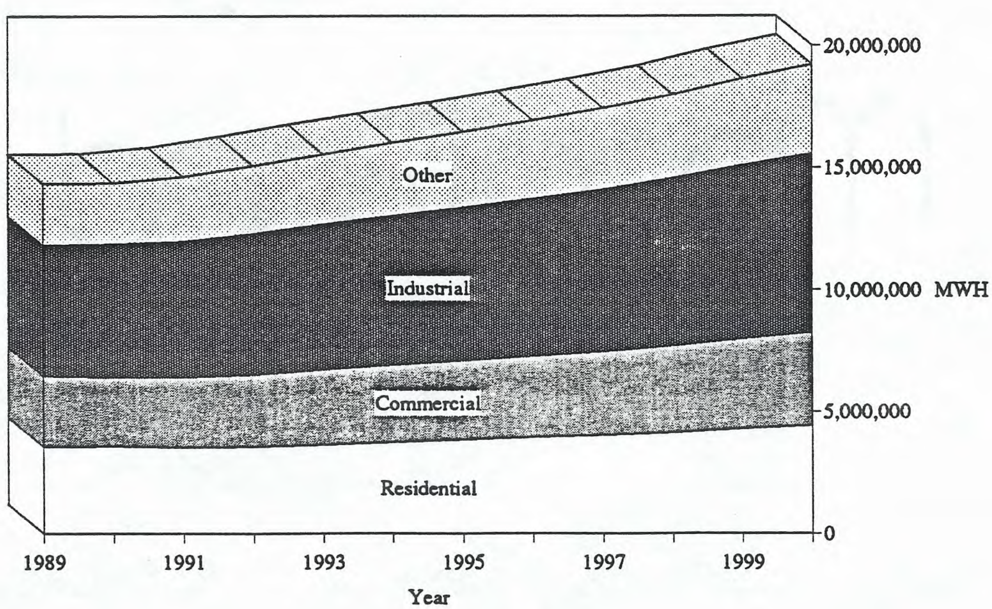
TABLE 3.29
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

Year	Staff Total Adjusted (MWH)	SWEPCO Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	14,338,070	13,749,136	588,934	4.28%
1990	14,372,585	13,553,481	819,104	6.04%
1991	14,642,587	14,287,582	355,005	2.48%
1992	15,064,927	14,737,538	327,389	2.22%
1993	15,560,266	15,145,546	414,720	2.74%
1994	16,013,241	15,643,965	369,276	2.36%
1995	16,460,513	16,215,910	244,603	1.51%
1996	16,931,058	16,636,620	294,438	1.77%
1997	17,425,913	17,057,403	368,510	2.16%
1998	17,993,557	17,472,763	520,794	2.98%
1999	18,654,057	17,887,465	766,592	4.29%
2000	19,226,978	18,264,510	962,468	5.27%
Avg. Annual Growth Rates 1989-2000	2.70%	2.62%		

TABLE 3.30
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	3,562,588	2,899,442	5,361,508	2,514,532	14,338,070
1990	3,595,060	2,831,127	5,452,714	2,493,684	14,372,585
1991	3,543,193	2,860,088	5,577,500	2,661,807	14,642,587
1992	3,560,453	2,969,274	5,767,785	2,767,415	15,064,927
1993	3,644,045	3,087,799	5,961,985	2,866,437	15,560,266
1994	3,740,895	3,171,124	6,131,883	2,969,339	16,013,241
1995	3,845,656	3,244,411	6,294,169	3,076,278	16,460,513
1996	3,940,006	3,332,830	6,470,805	3,187,417	16,931,058
1997	4,035,440	3,430,353	6,657,194	3,302,926	17,425,913
1998	4,140,073	3,555,562	6,874,942	3,422,981	17,993,557
1999	4,295,562	3,699,813	7,110,913	3,547,769	18,654,057
2000	4,434,741	3,823,511	7,321,881	3,646,845	19,226,978
Avg. Annual Growth Rates 1989-2000	2.01%	2.55%	2.87%	3.44%	2.70%

FIGURE 3.10
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL



Lower Colorado River Authority LCRA, like other Central Texas energy providers, is expected to show strong growth in peak demand. The Commission staff estimates that peak demand will grow at an average annual adjusted rate of 3.30 percent. LCRA's projection is 2.99 percent through the forecast period.

Continued population growth in Central Texas is expected to contribute to increases in electricity sales. The Commission Staff estimates that adjusted total system sales will grow at an average annual rate of 3.63 percent through the year 2000.

City of Austin Electric Utility Although the Austin area economy has little direct dependence on the oil industry, it nevertheless felt the impact of the Texas downturn. The construction sector was particularly hard hit during the late 1980's as a result of overbuilding and a speculative real estate market. The Austin economy is expected to improve, especially in the long-run, with reliance on its well-educated labor force and concentration of high-tech industries.

The Commission staff projects a robust adjusted average annual growth in peak demand of 2.85 percent through the year 2000. The City's expectations are somewhat more optimistic and are above staff's projections throughout the forecast period.

Total system sales are forecasted to grow at an average annual rate of 2.65 percent. Commercial sales are expected to show an increase of 3.67 percent through the forecast period while residential and industrial sales are projected to grow at 1.10 percent and 2.26 percent, respectively.

West Texas Utilities Company Staff forecasts that adjusted peak demand will increase at an annual average rate of 2.25 percent in the next decade. WTU projects a slower growth of 1.97 percent over the same period. The greatest difference between the two forecasts reaches 3.59 percent, but tapers toward the end of the forecast horizon.

Commercial sales are expected to exhibit the strongest growth at 2.64 percent while both residential and industrial sales are anticipated to grow at the slower rates of 1.93 and 1.65 percent, respectively. Total system sales are forecasted to grow at a steady average annual rate of 2.18 percent through the forecast period.

TABLE 3.31
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
LOWER COLORADO RIVER AUTHORITY

Year	Staff Adjusted (MW)	LCRA Adjusted (MW)	Difference (MW)	Difference (%)
1989	1,568	1,568		
1990	1,534	1,530	4	0.26%
1991	1,554	1,533	21	1.39%
1992	1,607	1,564	43	2.72%
1993	1,663	1,597	66	4.12%
1994	1,735	1,638	97	5.92%
1995	1,813	1,706	107	6.29%
1996	1,886	1,787	99	5.55%
1997	1,966	1,873	93	4.98%
1998	2,048	1,958	90	4.58%
1999	2,159	2,074	85	4.11%
2000	2,242	2,169	73	3.35%
Avg. Annual Growth Rates 1989-2000	3.30%	2.99%		

TABLE 3.32
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
LOWER COLORADO RIVER AUTHORITY

Year	Staff Total Adjusted (MWH)	LCRA Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	7,393,255	7,501,993	-108,738	-1.45%
1990	7,252,130	7,180,100	72,030	1.00%
1991	7,398,953	7,244,700	154,253	2.13%
1992	7,716,513	7,462,250	254,263	3.41%
1993	8,065,825	7,649,400	416,425	5.44%
1994	8,465,061	7,890,700	574,361	7.28%
1995	8,878,411	8,270,700	607,711	7.35%
1996	9,256,323	8,710,550	545,773	6.27%
1997	9,671,999	9,152,300	519,699	5.68%
1998	10,080,579	9,593,100	487,479	5.08%
1999	10,578,284	10,150,750	427,534	4.21%
2000	10,945,957	10,637,150	308,807	2.90%
Avg. Annual Growth Rates 1989-2000	3.63%	3.23%		

TABLE 3.33
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
LOWER COLORADO RIVER AUTHORITY

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	3,956,449	2,285,305	945,499	206,002	7,393,255
1990	3,915,242	2,165,274	961,930	209,683	7,252,130
1991	4,015,377	2,186,616	983,353	213,607	7,398,953
1992	4,165,852	2,314,190	1,017,890	218,581	7,716,513
1993	4,306,406	2,485,971	1,047,978	225,470	8,065,825
1994	4,469,285	2,686,101	1,075,823	233,852	8,465,061
1995	4,621,737	2,908,820	1,105,419	242,435	8,878,411
1996	4,751,067	3,120,377	1,133,725	251,154	9,256,323
1997	4,914,500	3,335,676	1,161,897	259,926	9,671,999
1998	5,080,725	3,540,609	1,190,516	268,729	10,080,579
1999	5,318,670	3,758,598	1,223,509	277,508	10,578,284
2000	5,485,699	3,922,700	1,252,358	285,201	10,945,957
Avg. Annual Growth Rates 1989-2000	3.02%	5.03%	2.59%	3.00%	3.63%

FIGURE 3.11
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
LOWER COLORADO RIVER AUTHORITY

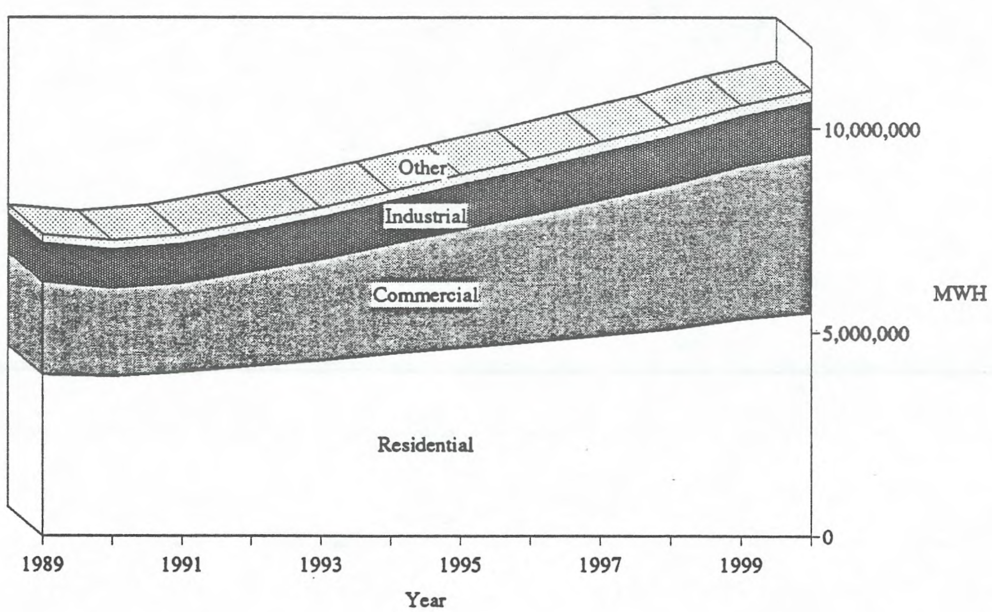


TABLE 3.34
COMPARISON OF UTILITY-PROVIDED AND PUCT STAFF PEAK DEMAND FORECAST CITY OF AUSTIN ELECTRIC UTILITY

Year	Staff Adjusted (MW)	COA Adjusted (MW)	Difference (MW)	Difference (%)
1989	1,408	1,408		
1990	1,486	1,495	-9	-0.63%
1991	1,492	1,530	-38	-2.48%
1992	1,520	1,573	-53	-3.37%
1993	1,559	1,619	-60	-3.71%
1994	1,607	1,670	-63	-3.77%
1995	1,655	1,723	-68	-3.95%
1996	1,701	1,796	-95	-5.29%
1997	1,746	1,866	-120	-6.43%
1998	1,790	1,948	-158	-8.11%
1999	1,850	2,049	-199	-9.71%
2000	1,918	2,164	-246	-11.37%
Avg. Annual Growth Rates 1989-2000	2.85%	3.98%		

TABLE 3.35
COMPARISON OF UTILITY-PROVIDED AND PUCT STAFF ELECTRIC ENERGY SALES FORECAST CITY OF AUSTIN ELECTRIC UTILITY

Year	Staff Total Adjusted (MWH)	COA Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	6,157,704	6,157,704		
1990	6,015,475	6,081,505	-66,030	-1.09%
1991	6,085,148	6,270,575	-185,427	-2.96%
1992	6,232,456	6,488,413	-255,957	-3.94%
1993	6,439,077	6,722,345	-283,268	-4.21%
1994	6,665,863	6,973,945	-308,082	-4.42%
1995	6,904,783	7,258,568	-353,785	-4.87%
1996	7,140,174	7,608,218	-468,044	-6.15%
1997	7,373,181	7,956,758	-583,577	-7.33%
1998	7,611,992	8,364,683	-752,691	-9.00%
1999	7,896,881	8,861,223	-964,342	-10.88%
2000	8,208,511	9,362,943	-1,154,433	-12.33%
Avg. Annual Growth Rates 1989-2000	2.65%	3.88%		

TABLE 3.36
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
CITY OF AUSTIN ELECTRIC UTILITY

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	2,368,423	2,993,970	626,319	168,992	6,157,704
1990	2,294,136	2,970,979	552,483	197,877	6,015,475
1991	2,273,713	3,024,446	579,459	207,531	6,085,148
1992	2,302,912	3,105,924	606,438	217,182	6,232,456
1993	2,336,176	3,244,409	632,120	226,373	6,439,077
1994	2,374,099	3,398,677	657,599	235,489	6,665,863
1995	2,424,411	3,551,302	684,095	244,975	6,904,783
1996	2,464,425	3,712,001	709,632	254,117	7,140,174
1997	2,493,073	3,886,289	731,777	262,043	7,373,181
1998	2,519,593	4,067,499	754,668	270,232	7,611,992
1999	2,588,550	4,250,964	778,573	278,794	7,896,881
2000	2,672,030	4,448,773	800,913	286,794	8,208,511
Avg. Annual Growth Rates 1989-2000	1.10%	3.67%	2.26%	4.93%	2.65%

FIGURE 3.12
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
CITY OF AUSTIN ELECTRIC UTILITY

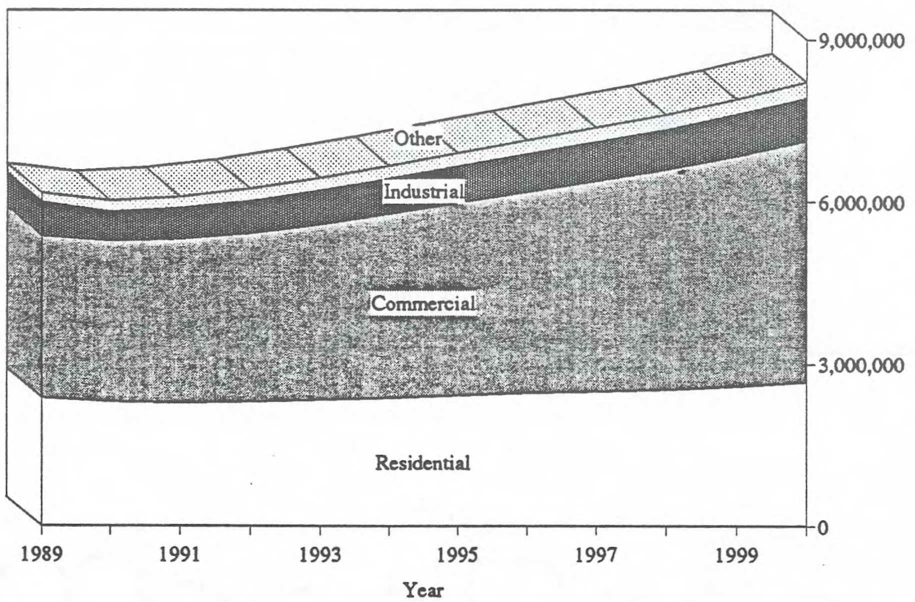


TABLE 3.37
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
WEST TEXAS UTILITY COMPANY

Year	Staff Adjusted (MW)	WTU Adjusted (MW)	Difference (MW)	Difference (%)
1989	1,134	1,134		
1990	1,152	1,128	24	2.14%
1991	1,168	1,159	9	0.80%
1992	1,187	1,188	-1	-0.05%
1993	1,211	1,210	1	0.04%
1994	1,240	1,238	2	0.13%
1995	1,273	1,267	6	0.45%
1996	1,306	1,295	11	0.82%
1997	1,342	1,324	18	1.33%
1998	1,378	1,351	27	1.97%
1999	1,419	1,379	40	2.87%
2000	1,459	1,406	53	3.81%
Avg. Annual Growth Rates 1989-2000	2.32%	1.97%		

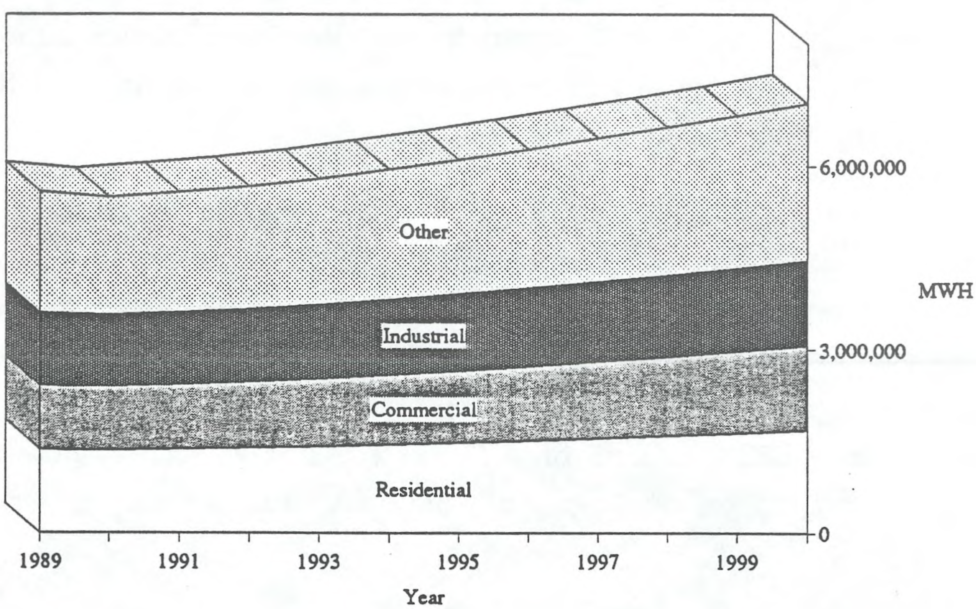
TABLE 3.38
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
WEST TEXAS UTILITY COMPANY

Year	Staff Total Adjusted (MWH)	WTU Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	5,581,127	5,581,127		
1990	5,486,934	5,535,200	-48,266	-0.87%
1991	5,568,227	5,633,400	-65,173	-1.16%
1992	5,666,139	5,748,300	-82,161	-1.43%
1993	5,794,169	5,842,800	-48,631	-0.83%
1994	5,944,406	5,982,500	-38,094	-0.64%
1995	6,107,954	6,119,500	-11,546	-0.19%
1996	6,277,466	6,258,900	18,566	0.30%
1997	6,456,474	6,404,600	51,874	0.81%
1998	6,637,550	6,551,300	86,250	1.32%
1999	6,827,750	6,699,100	128,650	1.92%
2000	7,021,644	6,849,800	171,844	2.51%
Avg. Annual Growth Rates 1989-2000	2.11%	1.88%		

TABLE 3.39
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
WEST TEXAS UTILITY COMPANY

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	1,365,295	1,038,361	1,202,106	1,975,365	5,581,127
1990	1,347,927	1,045,778	1,176,106	1,917,123	5,486,934
1991	1,366,718	1,061,643	1,185,928	1,953,938	5,568,227
1992	1,388,629	1,081,573	1,198,995	1,996,941	5,666,139
1993	1,413,462	1,107,668	1,217,471	2,055,568	5,794,169
1994	1,442,429	1,139,059	1,240,181	2,122,737	5,944,406
1995	1,476,282	1,174,296	1,264,550	2,192,826	6,107,954
1996	1,511,346	1,212,395	1,289,514	2,264,211	6,277,466
1997	1,548,011	1,253,120	1,315,347	2,339,997	6,456,474
1998	1,586,748	1,295,271	1,341,085	2,414,446	6,637,550
1999	1,635,042	1,338,585	1,366,688	2,487,435	6,827,750
2000	1,684,480	1,382,548	1,392,253	2,562,364	7,021,644
Avg. Annual Growth Rates 1989-2000	1.93%	2.64%	1.34%	2.39%	2.11%

FIGURE 3.13
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
WEST TEXAS UTILITIES COMPANY



El Paso Electric Company

The El Paso area was largely unaffected by the Texas economic downturn, bolstered in the past decade by strong growth in manufacturing and trade. However, the El Paso region is expected to benefit little from the economic recovery occurring in most of the state.

Staff estimates a peak demand of 983 MW for Texas by the year 2000. The projections estimated by staff and the Company are close throughout the forecast period. The largest difference is 1.52 percent occurring in 1991.

Texas commercial sales are forecasted to grow at an adjusted annual rate of 3.15 percent while residential sales are expected to grow at 2.90 percent. Growth in electricity sales to industrial customers are expected to be the slowest at an average annual rate of 0.85 percent. Total adjusted system sales in Texas are projected to increase at 2.49 percent per year.

Texas-New Mexico Power Company

The adjusted peak demand forecast developed by staff for TNP's Texas Operating Divisions is only slightly higher than the projections developed by the Company. Staff projects adjusted peak demand to grow at a 2.12 percent average annual rate over the next decade while TNP projects a 2 percent growth rate.

In order to recognize the diversity of TNP's Texas operating divisions, the Commission staff developed the energy sales forecasts in pairs of single equation models for the South and Non-South service areas. Total adjusted system sales are projected to grow at a 2.18 percent average annual growth rate. Residential and commercial sales are expected to grow in proximity at 2.83 and 2.81 percent, respectively. Industrial sales are forecasted to grow at a much lower rate of 1.05 percent through the forecast horizon. Staff did not propose adjustments to commercial or industrial sales.

Brazos Electric Power Cooperative

This is the first time staff has developed a forecast for BEPC. Growth in both peak demand and sales is expected to be strong due, in large part, to the insulative effects of Baylor University in Waco and Texas A & M University in College Station. Staff forecasts an adjusted average annual growth in peak demand of 3.28 percent through the year 2000. This compares with BEPC's forecast of 4.37 percent average annual growth. The Cooperative's projections are above staff's projections for each year in the forecast period.

TABLE 3.40
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
EL PASO ELECTRIC COMPANY - TEXAS

Year	Staff Adjusted (MW)	EPE Texas Adjusted (MW)	Difference (MW)	Difference (%)
1989	743	743		
1990	756	765	-9	-1.18%
1991	778	790	-12	-1.52%
1992	792	786	6	0.74%
1993	816	810	6	0.71%
1994	843	834	9	1.03%
1995	869	862	7	0.76%
1996	891	886	5	0.60%
1997	910	904	6	0.70%
1998	933	929	4	0.45%
1999	958	952	6	0.65%
2000	983	975	8	0.81%
Avg. Annual Growth Rates 1989-2000	2.58%	2.50%		

TABLE 3.41
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
EL PASO ELECTRIC COMPANY - TEXAS

Year	Staff Total Adjusted (MWH)	EPE Texas Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	3,587,413	3,587,413		
1990	3,624,253	3,721,723	-97,470	-2.62%
1991	3,738,293	3,846,951	-108,658	-2.82%
1992	3,796,885	3,781,975	14,910	0.39%
1993	3,906,002	3,898,008	7,994	0.21%
1994	4,037,362	4,030,119	7,243	0.18%
1995	4,165,011	4,172,640	-7,629	-0.18%
1996	4,273,290	4,308,750	-35,460	-0.82%
1997	4,357,462	4,413,381	-55,920	-1.27%
1998	4,469,341	4,531,223	-61,882	-1.37%
1999	4,588,231	4,649,904	-61,673	-1.33%
2000	4,701,125	4,774,103	-72,978	-1.53%
Avg. Annual Growth Rates 1989-2000	2.49%	2.63%		

TABLE 3.42
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
EL PASO ELECTRIC COMPANY - TEXAS

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	1,004,731	1,189,264	733,218	660,200	3,587,413
1990	989,602	1,230,217	717,446	686,988	3,624,253
1991	1,008,127	1,271,438	745,041	713,686	3,738,293
1992	1,028,984	1,322,274	751,455	694,172	3,796,885
1993	1,055,873	1,368,471	755,170	726,489	3,906,002
1994	1,109,896	1,409,528	761,996	755,942	4,037,362
1995	1,152,720	1,456,219	769,718	786,353	4,165,011
1996	1,193,173	1,499,147	777,482	803,487	4,273,290
1997	1,221,781	1,538,096	784,588	812,996	4,357,462
1998	1,274,343	1,578,898	791,476	824,624	4,469,341
1999	1,326,297	1,628,126	798,148	835,660	4,588,231
2000	1,375,696	1,673,635	804,656	847,139	4,701,125
Avg. Annual Growth Rates 1989-2000	2.90%	3.15%	0.85%	2.29%	2.49%

FIGURE 3.14
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
EL PASO ELECTRIC COMPANY - TEXAS

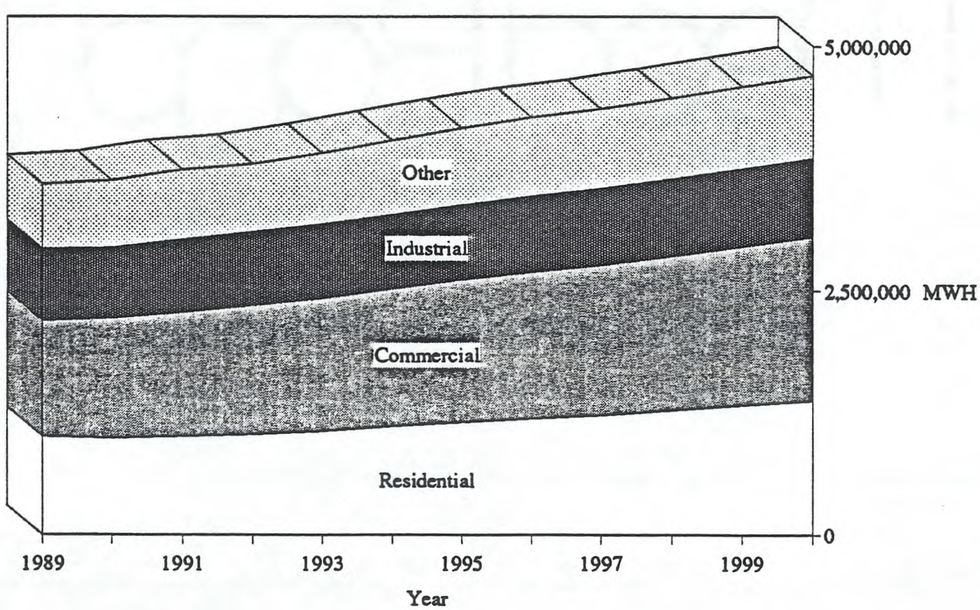


TABLE 3.43
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
EL PASO ELECTRIC COMPANY - TOTAL

Year	Staff Adjusted (MW)	EPE Total Adjusted (MW)	Difference (MW)	Difference (%)
1989	923	923		
1990	950	969	-19	-1.96%
1991	979	1,001	-22	-2.20%
1992	1,001	981	20	2.02%
1993	1,033	1,012	21	2.05%
1994	1,070	1,044	26	2.45%
1995	1,102	1,079	23	2.09%
1996	1,129	1,108	21	1.93%
1997	1,153	1,131	22	1.98%
1998	1,181	1,161	20	1.73%
1999	1,212	1,190	22	1.86%
2000	1,241	1,219	22	1.80%
Avg. Annual Growth Rates 1989-2000	2.73%	2.56%		

TABLE 3.44
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
EL PASO ELECTRIC COMPANY - TOTAL

Year	Staff Total Adjusted (MWH)	EPE Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	4,506,913	4,506,913		
1990	4,578,572	4,670,057	-91,485	-1.96%
1991	4,722,736	4,837,352	-114,616	-2.37%
1992	4,819,865	4,783,452	36,413	0.76%
1993	4,968,424	4,936,231	32,193	0.65%
1994	5,150,791	5,118,794	31,997	0.63%
1995	5,306,493	5,291,740	14,753	0.28%
1996	5,442,594	5,461,454	-18,860	-0.35%
1997	5,550,860	5,590,979	-40,119	-0.72%
1998	5,687,643	5,737,410	-49,767	-0.87%
1999	5,831,530	5,884,954	-53,424	-0.91%
2000	5,968,966	6,039,346	-70,380	-1.17%
Avg. Annual Growth Rates 1989-2000	2.59%	2.70%		

TABLE 3.45
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
EL PASO ELECTRIC COMPANY - TOTAL

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	1,299,771	1,423,852	763,650	1,019,640	4,506,913
1990	1,299,153	1,499,427	749,456	1,030,537	4,578,572
1991	1,327,854	1,550,681	777,811	1,066,390	4,722,736
1992	1,357,678	1,611,373	819,704	1,031,110	4,819,865
1993	1,394,743	1,669,665	831,526	1,072,491	4,968,424
1994	1,459,543	1,720,751	859,115	1,111,382	5,150,791
1995	1,513,107	1,775,266	866,940	1,151,180	5,306,493
1996	1,562,945	1,826,496	874,985	1,178,168	5,442,594
1997	1,600,534	1,872,537	882,007	1,195,782	5,550,860
1998	1,661,203	1,921,219	888,988	1,216,232	5,687,643
1999	1,722,602	1,977,215	895,688	1,236,026	5,831,530
2000	1,780,580	2,029,512	902,211	1,256,663	5,968,966
Avg. Annual Growth Rates 1989-2000	2.90%	3.27%	1.53%	1.92%	2.59%

FIGURE 3.15
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
EL PASO ELECTRIC COMPANY - TOTAL

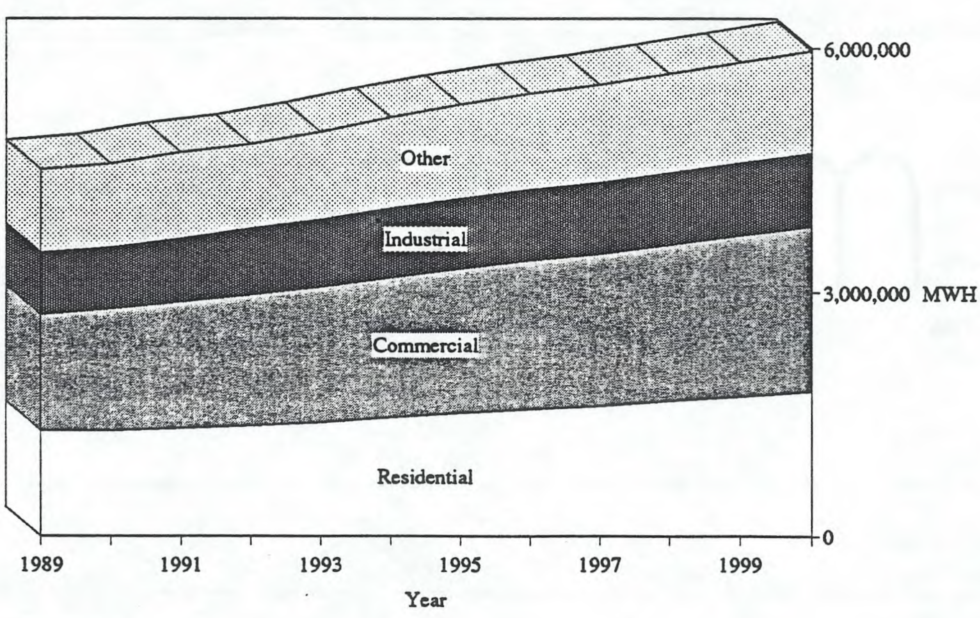


TABLE 3.46
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
TEXAS - NEW MEXICO POWER COMPANY

Year	Staff Adjusted (MW)	TNP Adjusted (MW)	Difference (MW)	Difference (%)
1989	968	968		
1990	1,003	978	25	2.56%
1991	1,020	986	34	3.40%
1992	1,026	1,000	26	2.65%
1993	1,038	1,024	14	1.40%
1994	1,054	1,047	7	0.68%
1995	1,072	1,072	0	0.01%
1996	1,089	1,097	-8	-0.74%
1997	1,122	1,122		-0.03%
1998	1,158	1,150	8	0.73%
1999	1,191	1,177	14	1.19%
2000	1,220	1,204	16	1.31%
Avg. Annual Growth Rates 1989-2000	2.12%	2.00%		

TABLE 3.47
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
TEXAS - NEW MEXICO POWER COMPANY

Year	Staff Total Adjusted (MWH)	TNP Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	4,850,017	4,850,017		
1990	5,044,249	4,926,288	117,961	2.39%
1991	5,131,971	4,943,585	188,386	3.81%
1992	5,186,598	4,989,483	197,115	3.95%
1993	5,270,396	5,094,517	175,879	3.45%
1994	5,366,558	5,199,878	166,680	3.21%
1995	5,460,674	5,309,047	151,627	2.86%
1996	5,546,980	5,421,104	125,876	2.32%
1997	5,703,733	5,536,181	167,552	3.03%
1998	5,871,857	5,654,345	217,512	3.85%
1999	6,019,866	5,775,824	244,042	4.23%
2000	6,147,610	5,900,732	246,878	4.18%
Avg. Annual Growth Rates 1989-2000	2.18%	1.80%		

TABLE 3.48
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
TEXAS - NEW MEXICO POWER COMPANY

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	1,742,462	1,202,984	1,788,668	115,903	4,850,017
1990	1,767,980	1,263,459	1,889,332	123,477	5,044,249
1991	1,817,439	1,284,569	1,904,823	125,140	5,131,971
1992	1,855,395	1,297,268	1,907,119	126,817	5,186,598
1993	1,894,190	1,326,363	1,921,335	128,508	5,270,396
1994	1,944,936	1,358,209	1,933,198	130,215	5,366,558
1995	1,996,793	1,386,540	1,945,404	131,937	5,460,674
1996	2,034,979	1,420,718	1,957,610	133,673	5,546,980
1997	2,104,603	1,493,888	1,969,816	135,426	5,703,733
1998	2,191,196	1,561,446	1,982,022	137,193	5,871,857
1999	2,291,807	1,594,853	1,994,228	138,978	6,019,866
2000	2,368,517	1,631,881	2,006,434	140,778	6,147,610
Avg. Annual Growth Rates 1989-2000	2.83%	2.81%	1.05%	1.78%	2.18%

FIGURE 3.16
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
TEXAS - NEW MEXICO POWER COMPANY

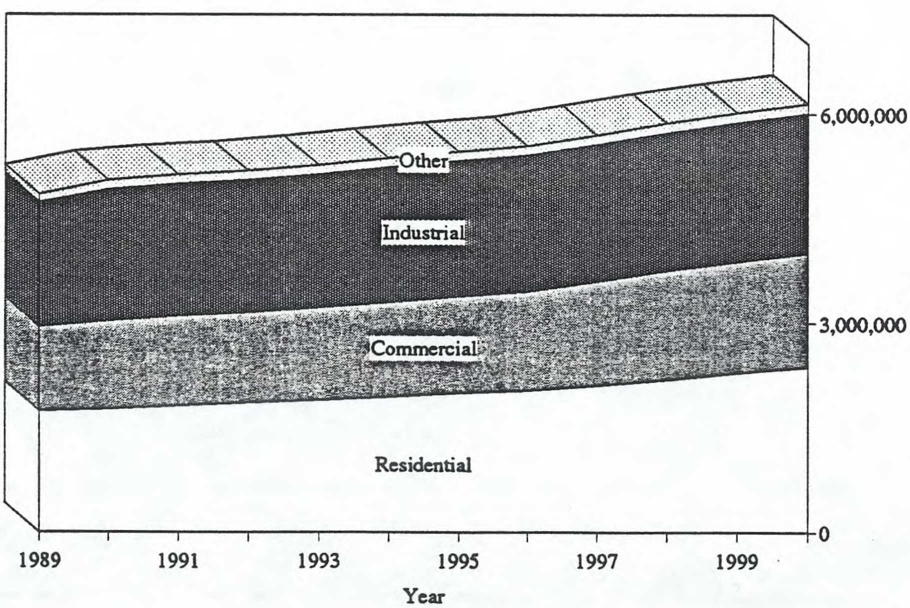


TABLE 3.49
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF PEAK DEMAND FORECAST
BRAZOS ELECTRIC POWER COOPERATIVE, INC.

Year	Staff Adjusted (MW)	BEPC Adjusted (MW)	Difference (MW)	Difference (%)
1989	811	811		
1990	869	897	-28	-3.12%
1991	925	934	-9	-1.02%
1992	962	966	-4	-0.46%
1993	1,004	1,005	-1	-0.15%
1994	1,036	1,042	-6	-0.54%
1995	1,067	1,079	-12	-1.07%
1996	1,103	1,119	-16	-1.46%
1997	1,148	1,160	-12	-1.00%
1998	1,190	1,202	-12	-0.98%
1999	1,231	1,240	-9	-0.74%
2000	1,270	1,279	-9	-0.74%
Avg. Annual Growth Rates 1989-2000	4.16%	4.23%		

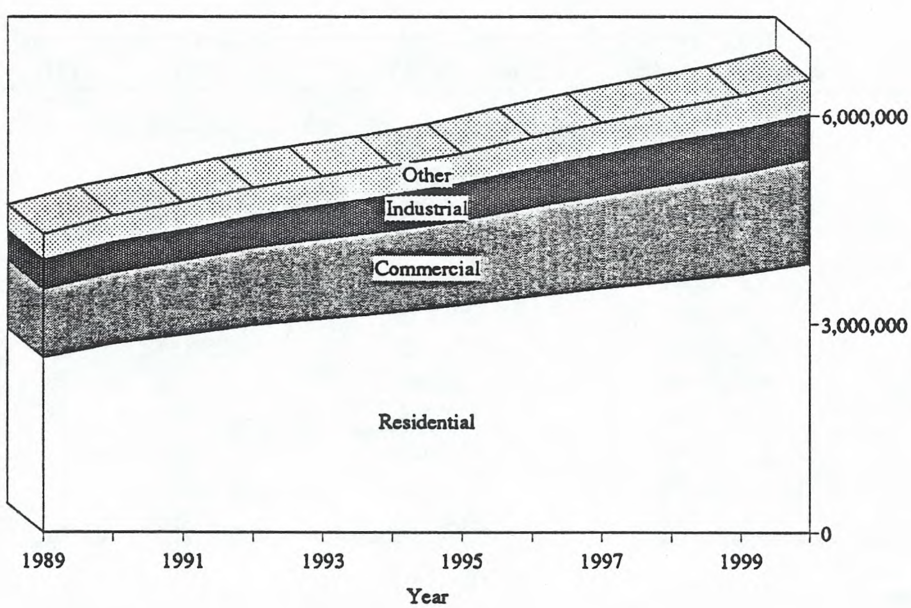
TABLE 3.50
COMPARISON OF UTILITY-PROVIDED AND PUCT
STAFF ELECTRIC ENERGY SALES FORECAST
BRAZOS ELECTRIC POWER COOPERATIVE, INC.

Year	Staff Total Adjusted (MWH)	BEPC Total Adjusted (MWH)	Difference (MWH)	Difference (%)
1989	4,287,790	4,287,790		
1990	4,558,150	4,647,741	-89,591	-1.93%
1991	4,747,795	4,874,801	-127,006	-2.61%
1992	4,961,354	5,092,929	-131,575	-2.58%
1993	5,124,788	5,354,775	-229,987	-4.29%
1994	5,284,693	5,559,759	-275,066	-4.95%
1995	5,460,558	5,776,392	-315,834	-5.47%
1996	5,692,775	6,000,246	-307,471	-5.12%
1997	5,901,500	6,234,289	-332,789	-5.34%
1998	6,099,242	6,482,028	-382,786	-5.91%
1999	6,289,114	6,669,087	-379,973	-5.70%
2000	6,529,259	6,864,239	-334,980	-4.88%
Avg. Annual Growth Rates 1989-2000	3.90%	4.37%		

TABLE 3.51
PUCT STAFF FORECAST OF
ELECTRIC ENERGY SALES BY CLASS
BRAZOS ELECTRIC POWER COOPERATIVE, INC.

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1989	2,511,958	985,117	423,564	367,150	4,287,790
1990	2,715,151	1,025,365	438,115	379,518	4,558,150
1991	2,851,256	1,064,325	442,232	389,982	4,747,795
1992	2,983,884	1,112,769	463,572	401,129	4,961,354
1993	3,076,939	1,147,493	489,185	411,171	5,124,788
1994	3,167,014	1,182,315	514,300	421,064	5,284,693
1995	3,281,917	1,209,487	542,862	426,292	5,460,558
1996	3,400,716	1,285,050	562,063	444,946	5,692,775
1997	3,514,503	1,341,582	587,768	457,648	5,901,500
1998	3,623,934	1,395,070	611,430	468,809	6,099,242
1999	3,723,980	1,452,197	629,991	482,947	6,289,114
2000	3,876,177	1,507,012	649,789	496,280	6,529,259
Avg. Annual Growth Rates 1989-2000	4.02%	3.94%	3.97%	2.78%	3.90%

FIGURE 3.17
STAFF-PROJECTED ELECTRIC ENERGY SALES BY CLASS
BRAZOS ELECTRIC POWER COOPERATIVE, INC.



The Commission staff projects strong sales growth for the major customer groups. Residential sales are expected to grow an average of 4.02 percent during the forecast period, followed closely by industrial and commercial sales at 3.97 and 3.94 percent, respectively.

Forecast Accuracy

Accurate forecasting of energy needs is essential for a number of reasons. Adequate energy supplies are important for the functioning of a modern economy. Long lead-in times are required to bring new generating capacity on line, and investments in new capacity are extremely capital intensive. Forecasts that are too low may result in shortages involving costs to the economy greater than the value of energy not supplied. Forecasts that are too high result in excess-capacity and an inefficient use of costly resources. Both scenarios result in costs that must be borne by consumers and/or utilities. Therefore, it is important that reliable forecasts are generated.

Factors beyond the control of electric utilities, such as the inability to forecast the severity and duration of the Texas economic recession of the mid-1980s, contribute to forecasting errors. However, there are errors that may be attributable to deficiencies in the models or methodologies employed by the utilities. These deficiencies include:

1. Inappropriate choice of methodology. For example, trying to produce long-term forecasts with a time-series model over a time period where rapid structural change in energy markets or the service area economy is anticipated
2. Imprecise parameter estimates. For example, inaccurate estimates of the relationships between energy demand and the factors premised to affect the demand
3. Misspecification of functional forms. For example, assuming that some linear relationship between prices and consumption exists, when the relationship is, in fact, non-linear
4. Violations of economic theory
5. Statistical problems
6. Exclusion of important factors

The thirteen major generating electric utilities have provided an overview of their respective forecast accuracies. The results are illustrated in Tables 3.52 through 3.64 and Charts 3.18 through 3.30.

PUCT Forecasting Record

In 1984 the Commission staff began generating long-term forecasts of sales (KWH) and peak demand (KW) for the major utilities operating in Texas. Ten-year forecasts are presented biennially and can be found in Volume I of the Commission's dated series of the **Long-Term Electric Peak Demand And Capacity Resource Forecast For Texas.**

Since 1984, the PUCT staff has been providing a forecast for the following eleven utilities:

Utility Name	Acronym
Texas Utilities Electric Company	TU Electric
Houston Lighting and Power Company	HL&P
Gulf States Utilities Company	GSU
Central Power and Light Company	CPL
City Public Service of San Antonio	CPS
Southwestern Public Service Company	SPS
Southwestern Electric Power Company	SWEPCO
Lower Colorado River Authority	LCRA
City of Austin	COA
West Texas Utilities Company	WTU
El Paso Electric Company	EPE

The Commission staff has created an index of forecast accuracy that will allow a comparison of staff's performance with that of the utilities. This index reflects the weighted average annual deviation of the forecasted peak demand (KW) in a given year from its actual value in percentage terms. Forecasts are compared before and after the various adjustments to demand. These adjustments include exogenous factors and conservation and load management programs (including interruptible loads).

The index is computed in the following manner. The percent deviation (in absolute value) of a one-year-ahead forecast from the actual peak is weighted with a six. A two-year-ahead forecast deviation is weighted with a five and so on. The sum of the weighted deviations are then divided by the total number of weights yielding the index number. The following example illustrates the construction of an index number:

	Year Forecast Issued					
	1983		1985		1987	
Year	%*	WEIGHT	%*	WEIGHT	%*	WEIGHT
1984	1	6				
1985	2	5				
1986	3	4	3	6		
1987	4	3	4	5		
1988	5	2	5	4	2	6
1989	6	1	6	3	1	5

* The deviation in absolute value, in percent, of the forecasted peak from actual peak.

Index Value = ((1*6) + (2*5) + (3*4) + (4*3) + (5*2) + (6*1) + (3*6) + (4*5) + (5*4) + (6*3) + (2*6) + (1*5)) / 50 = 2.98

The weights are designed to put greater reliance on current and short-term forecast information than on distant years. For example, a two percent deviation from the actual peak of a one-year-ahead forecast ahead should be treated differently than a two percent deviation in a one + n year-ahead forecast (n>0). Lower values of the index number are clearly preferable to higher values. The following table provides a summary of the forecast accuracy exhibited by the utilities and the Commission staff.

FORECAST ACCURACY

Utility Forecast (83, 85, 87) vs. Staff Forecast (84,86,88):

	AFTER ADJUSTMENTS	
UTILITY	UTILITY	STAFF
TU	3.82	3.70
HL&P	8.98	12.36
GSU	0.70	0.52
CPL	7.60	4.87
CPS	4.36	3.36
SPS	6.11	4.94
SWEPCO	4.87	5.73
LCRA	4.79	12.83
COA	9.06	6.00
WTU	6.56	4.84
EPE	6.47	6.91

No clear pattern emerges upon examining the forecasting performances of staff and the various utilities. Staff does not perform consistently better than the smaller or larger utilities. Staff's after adjustment forecast performance is superior to that of the utilities in seven out of eleven cases.

TABLE 3.52

UTILITY-PROJECTED PEAK DEMAND
TU ELECTRIC

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	10,002													
1977	11,531	10,525												
1978	12,354	11,602	11,232											
1979	13,213	12,328	11,851	10,880										
1980	14,127	13,086	12,459	12,351	12,591									
1981	15,091	14,214	13,487	13,374	13,422	12,970								
1982	16,124	15,043	14,170	14,051	14,136	13,735	13,204							
1983	17,206	15,917	14,895	14,770	14,864	14,365	14,260	14,029						
1984	18,361	16,833	15,662	15,531	15,622	15,035	14,900	14,260	15,189					
1985	19,580	17,800	16,475	16,337	16,448	15,755	15,590	14,845	14,800	15,769				
1986		18,813	17,336	17,191	17,308	16,485	16,300	15,445	15,400	15,820	16,407			
1987			18,250	18,098	18,224	17,250	17,040	16,055	16,100	16,285	16,567	16,567		
1988				19,048	19,180	18,050	17,805	16,735	16,700	16,860	17,055	17,057	17,460	
1989					20,171	18,890	18,600	17,410	17,400	17,340	17,528	17,504	17,519	16,944
Difference From Actual** (Percent)														
1976	10,002													
1977	9.56%	10,525												
1978	9.99%	3.29%	11,232											
1979	21.44%	13.31%	8.92%	10,880										
1980	12.20%	3.93%	-1.05%	-1.91%	12,591									
1981	16.35%	9.59%	3.99%	3.11%	3.48%	12,970								
1982	22.11%	13.93%	7.32%	6.41%	7.06%	4.02%	13,204							
1983	22.65%	13.46%	6.17%	5.28%	5.95%	2.40%	1.65%	14,029						
1984	20.88%	10.82%	3.11%	2.25%	2.85%	-1.01%	-1.90%	-6.12%	15,189					
1985	24.17%	12.88%	4.48%	3.60%	4.31%	-0.09%	-1.14%	-5.86%	-6.14%	15,769				
1986		14.66%	5.66%	4.78%	5.49%	0.48%	-0.65%	-5.86%	-6.14%	-3.58%	16,407			
1987			10.16%	9.24%	10.00%	4.12%	2.86%	-3.09%	-2.82%	-1.70%	0.00%	16,567		
1988				9.10%	9.85%	3.38%	1.98%	-4.15%	-4.35%	-3.44%	-2.32%	-2.31%	17,460	
1989					19.05%	11.48%	9.77%	2.75%	2.69%	2.34%	3.45%	3.31%	3.39%	16,944

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual
Source: Data provided by TU Electric, summer 1990.

TABLE 3.53

UTILITY-PROJECTED PEAK DEMAND
HOUSTON LIGHTING AND POWER

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	8,019													
1977	8,709	8,445												
1978	9,218	9,206	9,114											
1979	9,603	9,747	9,686	9,336										
1980	9,950	10,387	10,322	10,150	10,266									
1981	10,400	10,943	10,780	10,550	10,455	10,540								
1982	11,000	11,425	11,291	10,900	10,914	10,971	10,594							
1983	11,450	11,700	11,800	11,325	11,142	11,517	11,348	10,676						
1984	12,300	12,150	12,275	11,925	11,314	12,052	11,947	11,689	10,851					
1985	12,700	12,675	12,925	12,425	11,802	12,494	12,228	12,091	11,501	10,618				
1986		13,225	13,500	12,900	12,096	12,900	12,656	12,430	11,906	10,712	10,556			
1987		13,775	14,075	13,325	12,486	13,275	13,084	12,863	12,291	10,771	9,834	10,302		
1988			14,725	13,775	12,926	13,675	13,635	13,205	12,702	11,190	9,899	10,515	10,422	
1989					13,310	14,200	14,209	13,722	13,177	11,710	10,619	10,388	10,288	10,456
Difference From Actual** (Percent)														
1976	8,019													
1977	-3.13%	8,445												
1978	1.14%	1.01%	9,114											
1979	2.86%	4.40%	3.75%	9,336										
1980	-3.08%	1.18%	0.55%	-1.13%	10,266									
1981	-1.33%	3.82%	2.28%	0.09%	-0.81%	10,540								
1982	3.83%	7.84%	6.58%	2.89%	3.02%	3.56%	10,594							
1983	7.25%	9.59%	10.53%	6.08%	4.36%	7.88%	6.29%	10,676						
1984	13.35%	11.97%	13.12%	9.90%	4.27%	11.07%	10.10%	7.72%	10,851					
1985	19.61%	19.37%	21.73%	17.02%	11.15%	17.67%	15.16%	13.87%	8.32%	10,618				
1986		25.28%	27.89%	22.21%	14.59%	22.21%	19.89%	17.75%	12.79%	1.48%	10,556			
1987		33.71%	36.62%	29.34%	21.20%	28.86%	27.00%	24.86%	19.31%	4.55%	-4.54%	10,302		
1988			41.29%	32.17%	24.03%	31.21%	30.83%	26.70%	21.88%	7.37%	-5.02%	0.89%	10,422	
1989					27.30%	35.81%	35.89%	31.24%	26.02%	11.99%	1.56%	-0.65%	-1.61%	10,456

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual
Source: Data provided by HL&P, summer 1990.

TABLE 3.54

UTILITY-PROJECTED PEAK DEMAND
GULF STATES UTILITIES

FORECASTED YEAR	YEAR FORECAST ISSUED 1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	4,162													
1977	4,482	4,657												
1978	4,706	4,936	5,138											
1979	4,941	5,222	5,477	5,229										
1980	5,189	5,441	5,611	5,478	5,604									
1981	5,447	5,674	5,942	5,779	5,630	5,542								
1982	5,720	5,918	6,274	6,097	6,011	5,726	5,164							
1983	5,706	6,165	6,651	6,398	6,294	6,024	5,432	5,348						
1984	5,991	6,018	6,950	6,680	6,589	6,196	5,577	5,600	5,475					
1985	6,291	6,259	7,466	6,938	6,801	6,354	5,731	5,555	5,522	5,139				
1986	6,605	6,509	7,914	7,119	7,020	6,520	5,874	5,543	5,402	5,182	5,089			
1987		6,675	8,373	7,361	7,245	6,689	5,961	5,632	5,454	5,029	5,030	4,991		
1988			8,859	7,574	7,478	6,849	6,050	5,719	5,469	5,101	5,025	5,045	4,910	
					7,719	7,008	6,158	5,802	5,589	5,208	5,085	5,048	5,052	5,015
Difference From Actual** (Percent)														
1976	4,162													
1977	-3.76%	4,657												
1978	-8.41%	-3.93%	5,138											
1979	-5.51%	-0.13%	4.74%	5,229										
1980	-7.41%	-2.91%	0.12%	-2.25%	5,604									
1981	-1.71%	2.38%	7.22%	4.28%	1.59%	5,542								
1982	10.77%	14.60%	21.49%	18.07%	16.40%	10.88%	5,164							
1983	6.69%	15.28%	24.36%	19.63%	17.69%	12.64%	1.57%	5,348						
1984	9.42%	9.92%	26.94%	22.01%	20.35%	13.17%	1.86%	2.28%	5,475					
1985	22.42%	21.79%	45.28%	35.01%	32.34%	23.64%	11.52%	8.09%	7.45%	5,139				
1986	29.79%	27.90%	55.51%	39.89%	37.94%	28.12%	15.43%	8.92%	6.15%	1.83%	5,089			
1987		33.74%	67.76%	47.49%	45.16%	34.02%	19.43%	12.84%	9.28%	0.76%	0.78%	4,991		
1988			80.43%	54.26%	52.30%	39.49%	23.22%	16.48%	11.38%	3.89%	2.34%	2.75%	4,910	
1989					53.92%	39.74%	22.79%	15.69%	11.45%	3.85%	1.40%	0.66%	0.74%	5,015

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual
Source: Data provided by GSU, summer 1990.

TABLE 3.55

UTILITY-PROJECTED PEAK DEMAND
CENTRAL POWER AND LIGHT

FORECASTED YEAR	YEAR FORECAST ISSUED 1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	**2,024**													
1977	2,314	**2,323**												
1978	2,455	2,376	**2,341**											
1979	2,591	2,527	2,576	**2,433**										
1980	2,700	2,650	2,824	2,623	**2,505**									
1981		2,717	2,844	2,743	2,624	**2,734**								
1982		2,833	3,009	3,010	2,858	2,838	**2,825**							
1983			3,148	3,126	3,049	2,979	3,091	**2,869**						
1984			3,280	3,255	3,243	3,113	3,251	3,031	**2,832**					
1985			3,416	3,412	3,461	3,265	3,433	3,173	3,136	**3,022**				
1986			3,593	3,571	3,594	3,449	3,574	3,242	3,220	3,171	**2,974**			
1987			3,755	3,733	3,740	3,649	3,735	3,368	3,016	3,211	3,101	**2,881**		
1988			3,951	3,900	3,916	3,783	3,903	3,464	3,116	3,095	2,990	2,893	**3,013**	
1989												2,948	3,186	**3,044**
Difference From Actual** (Percent)														
1976	2,024													
1977	0.39%	2,323												
1978	4.87%	1.50%	2,341											
1979	6.49%	3.86%	5.88%	2,433										
1980	7.78%	5.79%	12.73%	4.71%	2,505									
1981		-0.62%	4.02%	0.33%	-4.02%	2,734								
1982		0.28%	6.51%	6.55%	1.17%	0.46%	2,825							
1983			9.72%	8.96%	6.27%	3.83%	7.74%	2,869						
1984			15.82%	14.94%	14.51%	9.92%	14.80%	7.03%	2,832					
1985			13.04%	12.91%	14.53%	8.04%	13.60%	5.00%	3.77%	3,022				
1986			20.81%	20.07%	20.85%	15.97%	20.17%	9.01%	8.27%	6.62%	2,974			
1987			30.34%	29.57%	29.82%	26.66%	29.64%	16.90%	4.69%	11.45%	7.64%	2,881		
1988			31.13%	29.44%	29.97%	25.56%	29.54%	14.97%	3.42%	2.72%	-0.76%	-3.98%	3,013	
1989												-3.15%	4.66%	3,044

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual
Source: Data provided by CPL, summer 1990.

TABLE 3.56

UTILITY-PROJECTED PEAK DEMAND
CITY PUBLIC SERVICE OF SAN ANTONIO

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	1,560													
1977	1,683	1,641												
1978	1,827	1,742	1,688											
1979	1,996	1,858	1,834	1,707										
1980	2,173	1,981	1,963	1,851	1,950									
1981	2,367	2,122	2,124	1,979	1,855	1,911								
1982	2,538	2,270	2,270	2,157	1,947	1,997	1,984							
1983	2,711	2,422	2,409	2,339	2,050	2,084	2,090	2,148						
1984	2,874	2,565	2,543	2,489	2,172	2,202	2,159	2,158	2,210					
1985	3,055	2,726	2,693	2,643	2,291	2,314	2,223	2,198	2,237	2,350				
1986	3,234	2,882	2,841	2,783	2,433	2,449	2,321	2,254	2,327	2,460	2,596			
1987		3,041	3,000	2,928	2,560	2,571	2,474	2,368	2,452	2,589	2,533	2,551		
1988			3,188	3,088	2,675	2,683	2,592	2,461	2,552	2,698	2,661	2,638	2,664	
1989				3,236	2,840	2,819	2,756	2,556	2,677	2,852	2,816	2,769	2,743	2,697
Difference From Actual** (Percent)														
1976	1,560													
1977	2.56%	1,641												
1978	4.88%	3.20%	1,688											
1979	7.43%	1.31%	7.44%	1,707										
1980	9.69%	0.92%	6.05%	-5.08%	1,950									
1981	11.55%	-0.09%	7.33%	6.68%	-2.93%	1,911								
1982	11.81%	0.00%	5.24%	10.79%	-2.50%	0.66%	1,984							
1983	11.93%	0.54%	2.99%	14.10%	-1.63%	-0.29%	-2.70%	2,148						
1984	12.05%	0.87%	2.17%	14.59%	-1.36%	1.99%	0.05%	-2.35%	2,210					
1985	12.07%	1.23%	1.89%	15.36%	-0.99%	4.09%	1.14%	-1.74%	-4.81%	2,350				
1986	12.21%	1.44%	2.08%	14.39%	-0.65%	5.51%	2.97%	-3.14%	-5.41%	-5.24%	2,596			
1987		1.37%	2.46%	14.38%	-0.43%	3.92%	4.48%	-3.43%	-5.29%	2.21%	-0.71%	2,551		
1988			3.24%	15.44%	-0.30%	3.51%	5.32%	-3.57%	-5.41%	1.39%	0.87%	-0.98%	2,664	
1989				13.94%	0.74%	2.29%	7.82%	-4.52%	-6.14%	1.28%	1.70%	0.95%	1.71%	2,697

* Actual demands are shown in bold
** (Forecast - Actual) / Actual
Source: Data provided by CPSB, summer 1990.

TABLE 3.57

UTILITY-PROJECTED PEAK DEMAND
SOUTHWESTERN PUBLIC SERVICE COMPANY

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976														
1977	2,125													
1978	2,254	2,254	2,303											
1979	2,389	2,389	2,388	1,992										
1980	2,533	2,533	2,532	2,532	2,495									
1981	2,686	2,686	2,697	2,697	2,520	2,581								
1982	2,833	2,833	2,866	2,866	2,634	2,634	2,385							
1983	2,986	2,986	3,047	3,047	2,754	2,754	2,715	2,695						
1984	3,147	3,147	3,224	3,224	2,878	2,878	2,814	2,918	2,762					
1985	3,303	3,303	3,411	3,411	3,008	3,008	2,917	3,027	3,139	2,837				
1986	3,467	3,467	3,610	3,610	3,144	3,144	3,020	3,135	3,253	3,017	2,883			
1987		3,640	3,820	3,820	3,286	3,286	3,123	3,241	3,365	3,106	2,937	2,790		
1988			4,043	4,043	3,434	3,434	3,227	3,347	3,477	3,196	2,987	2,860	2,798	
1989				4,266	3,589	3,589	3,335	3,458	3,595	3,288	3,037	2,904	2,921	2,989
Difference From Actual** (Percent)														
1976														
1977														
1978	-2.13%	-2.13%	2,303											
1979	19.93%	19.93%	19.88%	1,992										
1980	1.52%	1.52%	1.48%	1.48%	2,495									
1981	4.07%	4.07%	4.49%	4.49%	-2.36%	2,581								
1982	18.78%	18.78%	20.17%	20.17%	10.44%	10.44%	2,385							
1983	10.80%	10.80%	13.06%	13.06%	2.19%	2.19%	0.74%	2,695						
1984	13.94%	13.94%	16.73%	16.73%	4.20%	4.20%	1.88%	5.65%	2,762					
1985	16.43%	16.43%	20.23%	20.23%	6.03%	6.03%	2.82%	6.70%	10.65%	2,837				
1986	20.26%	20.26%	25.22%	25.22%	9.05%	9.05%	4.75%	8.74%	12.83%	4.65%	2,883			
1987		30.47%	36.92%	36.92%	17.78%	17.78%	11.94%	16.16%	20.61%	11.33%	5.27%	2,790		
1988			44.50%	44.50%	22.73%	22.73%	15.33%	19.62%	24.27%	14.22%	6.75%	2.22%	2,798	
1989				42.72%	20.07%	20.07%	11.58%	15.69%	20.27%	10.00%	1.61%	-2.84%	-2.28%	2,989

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual
Source: Data provided by SPS, summer 1990.

TABLE 3.58

UTILITY-PROJECTED PEAK DEMAND
SOUTHWESTERN ELECTRIC POWER COMPANY

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	2,117													
1977	2,520	2,404												
1978	2,520	2,470	2,360											
1979	2,747	2,670	2,465	2,291										
1980	2,994	2,880	2,645	2,645	2,652									
1981	3,263	3,115	2,835	2,780	2,685	2,723								
1982	3,557	3,360	3,045	2,960	2,790	2,835	2,668							
1983	3,840	3,630	3,265	3,150	2,905	2,945	2,895	2,849						
1984	4,140	3,921	3,500	3,355	3,020	3,065	3,065	3,010	2,948					
1985	4,470	4,235	3,755	3,575	3,140	3,190	3,190	3,130	3,045	2,943				
1986	4,830	4,575	4,025	3,805	3,265	3,315	3,315	3,255	3,160	3,015	3,140			
1987	5,120	4,850	4,270	3,995	3,395	3,450	3,450	3,385	3,280	3,120	3,030	3,085		
1988	5,425	5,140	4,525	4,195	3,535	3,585	3,585	3,522	3,405	3,230	3,135	3,030	3,153	
1989			4,795	4,405	3,635	3,715	3,730	3,665	3,535	3,245	3,120	3,120	3,060	3,045
Difference From Actual** (Percent)														
1976	2,117													
1977	-104.83%	2,404												
1978	6.78%	4.66%	2,360											
1979	19.90%	16.54%	7.59%	2,291										
1980	12.90%	8.60%	-0.26%	-0.26%	2,652									
1981	19.83%	14.40%	4.11%	2.09%	-1.40%	2,723								
1982	33.32%	25.94%	14.13%	10.94%	4.57%	6.26%	2,668							
1983	34.78%	27.41%	14.60%	10.57%	1.97%	3.37%	1.61%	2,849						
1984	40.43%	33.01%	18.72%	13.81%	2.44%	3.97%	3.97%	2.10%	2,948					
1985	51.89%	43.90%	27.59%	21.47%	6.69%	8.39%	8.39%	6.35%	3.47%	2,943				
1986	53.82%	45.70%	28.18%	21.18%	3.98%	5.57%	5.57%	3.66%	0.64%	-3.98%	3,140			
1987	65.96%	57.21%	38.41%	29.50%	10.05%	11.83%	11.83%	9.72%	6.32%	1.13%	-1.78%	3,085		
1988	72.06%	63.02%	43.51%	33.05%	12.12%	13.70%	13.70%	11.70%	7.99%	2.44%	-0.57%	-3.90%	3,153	
1989				44.66%	19.38%	22.00%	22.50%	20.36%	16.09%	6.57%	2.46%	2.46%	0.49%	3,045

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual
Source: Data provided by SWEPCO, summer 1990.

TABLE 3.59

UTILITY-PROJECTED PEAK DEMAND
LOWER COLORADO RIVER AUTHORITY

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	792													
1977	911	869												
1978	992	932	888											
1979	1,075	1,000	936	868										
1980	1,159	1,066	992	1,021	1,067									
1981	1,248	1,137	1,052	1,085	1,057	1,078								
1982	1,343	1,212	1,115	1,153	1,115	1,128	1,158							
1983	1,447	1,293	1,182	1,226	1,177	1,188	1,200	1,221						
1984	1,558	1,379	1,254	1,304	1,243	1,253	1,271	1,276	1,314					
1985									1,322	1,434				
1986									1,388	1,467	1,515			
1987									1,458	1,578	1,430	1,514		
1988									1,529	1,690	1,520	1,532	1,555	
1989									1,613	1,816	1,590	1,592	1,565	1,568
Difference From Actual** (Percent)														
1976	792													
1977	-104.83%	869												
1978	11.71%	4.95%	888											
1979	23.85%	15.21%	7.83%	868										
1980	8.62%	-0.09%	-7.03%	-4.31%	1067									
1981	15.77%	5.47%	-2.41%	0.65%	-1.95%	1078								
1982	15.98%	4.66%	-3.71%	-0.43%	-3.71%	-2.59%	1158							
1983	18.51%	5.90%	-3.19%	0.41%	-3.60%	-2.70%	-1.72%	1221						
1984	18.57%	4.95%	-4.57%	-0.76%	-5.40%	-4.64%	-3.27%	-2.89%	1314					
1985									-7.81%	1434				
1986									-8.38%	-3.17%	1515			
1987									-3.70%	4.23%	-5.55%	1514		
1988									-1.67%	8.68%	-2.25%	-1.48%	1555	
1989									2.87%	15.82%	1.40%	1.53%	-0.19%	1568

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual
Source: Data provided by LCRA, summer 1990.

TABLE 3.60

UTILITY-PROJECTED PEAK DEMAND
CITY OF AUSTIN ELECTRIC UTILITY

FORECASTED YEAR	YEAR FORECAST ISSUED												
	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)													
1982						1,013							
1983						1,066	1,101						
1984						1,133	NA	1,210					
1985						1,201	NA	1,306	1,320				
1986						1,247	NA	1,411	1,387	1,402			
1987						1,293	NA	1,521	1,477	1,506	1,391		
1988						1,335	NA	1,607	1,570	1,577	1,535	1,396	
1989						1,375	NA	1,691	1,665	1,670	1,580	1,573	1,408
Difference From Actual ** (Percent)													
1982						1013							
1983						-3.18%	1101						
1984						-6.36%	NA	1210					
1985						-9.02%	NA	-1.06%	1320				
1986						-11.06%	NA	0.64%	-1.07%	1402			
1987						-7.05%	NA	9.35%	6.18%	8.27%	1391		
1988						-4.37%	NA	15.11%	12.46%	12.97%	9.96%	1396	
1989						-2.34%	NA	20.10%	18.25%	18.61%	12.22%	11.72%	1408

* Actual demands are shown in bold
** (Forecast - Actual)/Actual
Source: Data provided by COA, summer 1990.

TABLE 3.61

UTILITY-PROJECTED PEAK DEMAND
WEST TEXAS UTILITIES COMPANY

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	725													
1977	785	785												
1978	830	795	857											
1979	880	829	885	819										
1980	935	867	934	937	954									
1981	985	905	981	985	958	974								
1982	1,040	947	1,027	1,030	996	994	994							
1983	1,095	991	1,072	1,075	1,035	1,031	1,028	1,049						
1984	1,155	1,037	1,121	1,125	1,076	1,069	1,071	1,071	1,079					
1985	1,220	1,087	1,170	1,118	1,118	1,109	1,116	1,140	1,127	1,089				
1986	1,280	1,135	1,219	1,163	1,163	1,151	1,161	1,181	1,170	1,152	1,120			
1987		1,185	1,272	1,209	1,209	1,193	1,207	1,224	1,214	1,192	1,167	1,077		
1988			1,329	1,255	1,255	1,212	1,254	1,266	1,258	1,232	1,232	1,142	1,100	
1989				1,303	1,303	1,246	1,303	1,309	1,302	1,272	1,273	1,193	1,128	1,148
Difference From Actual** (Percent)														
1976	725													
1977	0.00%	785												
1978	-3.15%	-7.23%	857											
1979	7.45%	1.22%	8.06%	819										
1980	-1.99%	-9.12%	-2.10%	-1.78%	954									
1981	1.13%	-7.08%	0.72%	1.13%	-1.64%	974								
1982	4.63%	-4.73%	3.32%	3.62%	0.20%	0.00%	994							
1983	4.39%	-5.53%	2.19%	2.48%	-1.33%	-1.72%	-2.00%	1049						
1984	7.04%	-3.89%	3.89%	4.26%	-0.28%	-0.93%	-0.74%	-0.74%	1079					
1985	12.03%	-0.18%	7.44%	2.66%	2.66%	1.84%	2.48%	4.68%	3.49%	1089				
1986	14.29%	1.34%	8.84%	3.84%	3.84%	2.77%	3.66%	5.45%	4.46%	2.86%	1120			
1987		10.03%	18.11%	12.26%	12.26%	10.77%	12.07%	13.65%	12.72%	10.68%	8.36%	1077		
1988			20.82%	14.09%	14.09%	10.18%	14.00%	15.09%	14.36%	12.00%	12.00%	3.82%	1100	
1989				13.50%	13.50%	8.54%	13.50%	14.02%	13.41%	10.80%	10.89%	3.92%	-1.74%	1148

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual
Source: Data provided by WTU, summer 1990..

TABLE 3.62

UTILITY-PROJECTED PEAK DEMAND
EL PASO ELECTRIC COMPANY

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	677													
1977	669	657												
1978	706	691	690											
1979	759	738	718	688										
1980	819	799	775	712	793									
1981	892	879	848	744	819	813								
1982	952	936	909	790	840	840	747							
1983	1,016	996	984	821	821	821	832	749						
1984	1,084	1,076	1,038	849	849	849	961	825	834					
1985	1,157	1,135	1,113	904	904	904	981	875	884	877				
1986	1,235	1,195	1,166	936	936	936	1,028	1,020	920	979	938			
1987		1,258	1,223	983	983	983	1,095	1,098	998	1,044	1,024	975		
1988			1,275	1,030	1,030	1,030	1,131	1,126	1,026	1,061	1,045	1,019	1,002	
1989				1,085	1,085	1,085	1,076	1,175	1,075	1,106	1,092	1,055	1,055	1,076
Difference From Actual** (Percent)														
1976	677													
1977	1.83%	657												
1978	2.32%	0.14%	690											
1979	10.32%	7.27%	4.36%	688										
1980	3.28%	0.76%	-2.27%	-10.21%	793									
1981	9.72%	8.12%	4.31%	-8.49%	0.74%	813								
1982	27.44%	25.30%	21.69%	5.76%	12.45%	12.45%	747							
1983	35.65%	32.98%	31.38%	9.61%	9.61%	9.61%	11.08%	749						
1984	29.98%	29.02%	24.46%	1.80%	1.80%	1.80%	15.23%	-1.08%	834					
1985	31.93%	29.42%	26.91%	3.08%	3.08%	3.08%	11.86%	-0.23%	0.80%	877				
1986	31.66%	27.40%	24.31%	-0.21%	-0.21%	-0.21%	9.59%	8.74%	-1.92%	4.37%	938			
1987		29.03%	25.44%	0.82%	0.82%	0.82%	12.31%	12.62%	2.36%	7.08%	5.03%	975		
1988			27.25%	2.79%	2.79%	2.79%	12.87%	12.38%	2.40%	5.89%	4.29%	1.70%	1002	
1989				0.84%	0.84%	0.84%	0.00%	9.20%	-0.09%	2.79%	1.49%	-1.95%	-1.95%	1076

* Actual demands are shown in bold
** (Forecast - Actual) / Actual
Source: Data provided by EPE.

TABLE 3.63

UTILITY-PROJECTED PEAK DEMAND
TEXAS-NEW MEXICO POWER COMPANY

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	705													
1977	746	736												
1978	810	791	783											
1979	863	846	NA	797										
1980	894	884	NA	904	883									
1981	939	948	NA	1,037	921	930								
1982	NA	995	NA	1,087	975	943	919							
1983	NA	NA	NA	1,122	1,108	1,074	953	908						
1984	NA	NA	NA	1,161	1,236	1,178	1,047	1,016	930					
1985	NA	NA	NA	NA	1,246	1,209	1,122	1,092	1,139	986				
1986		NA	NA	NA		1,194	1,156	1,177	1,226	1,042	1,019			
1987			NA	NA		1,263	1,192	1,206	1,076	998	955	933		
1988				NA		1,304	1,251	1,238	1,119	1,046	980	973	981	
1989						1,346	1,304	1,296	1,164	1,094	1,003	997	952	968
Difference From Actual** (Percent)														
1976	705													
1977	1.36%	736												
1978	3.45%	1.02%	783											
1979	8.28%	6.15%	NA	797										
1980	1.25%	0.11%	NA	2.38%	883									
1981	0.97%	1.94%	NA	11.51%	-0.97%	930								
1982	NA	8.27%	NA	18.28%	6.09%	2.61%	919							
1983	NA	NA	NA	23.57%	22.03%	18.28%	4.96%	908						
1984	NA	NA	NA	24.84%	32.90%	26.67%	12.58%	9.25%	930					
1985	NA	NA	NA	NA	26.37%	22.62%	13.79%	10.75%	15.52%	986				
1986		NA	NA	NA	NA	17.17%	13.44%	15.51%	20.31%	2.26%	1019			
1987			NA	NA	NA	35.37%	27.76%	29.26%	15.33%	6.97%	2.36%	933		
1988				NA	NA	32.93%	27.52%	26.20%	14.07%	6.63%	-0.10%	-0.82%	981	
1989					NA	39.05%	34.71%	33.88%	20.25%	13.02%	3.62%	3.00%	-1.65%	968

* Actual demands are shown in parentheses.
** (Forecast - Actual) / Actual

Source: Data provided by TNP, summer 1990.

TABLE 3.64

UTILITY-PROJECTED PEAK DEMAND
BRAZOS ELECTRIC POWER COOPERATIVE

FORECASTED YEAR	YEAR FORECAST ISSUED													
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Peak Demand* (MW)														
1976	380													
1977	407	382												
1978	446		449											
1979	490			405										
1980	537			518	508									
1981	584			563		520								
1982	635			608			531							
1983	691			656				624						
1984	752			708				609	650					
1985	818			768				640		721				
1986				829				676		777	764			
1987				894				750		846	829	762		
1988				965				780		923	923	839	811	
1989								816		1,019	977	913	839	958
Difference From Actual** (Percent)														
1976	380													
1977	6.54%	382												
1978	-0.67%		449											
1979	20.99%			405										
1980	5.71%			1.97%	508									
1981	12.31%			8.27%		520								
1982	19.59%			14.50%			531							
1983	10.74%			5.13%				624						
1984	15.69%			8.92%				-6.31%	650					
1985	13.45%			6.52%				-11.23%		721				
1986				8.51%				-11.52%		1.70%	764			
1987				17.32%				-1.57%		11.02%	8.79%	762		
1988				18.99%				-3.82%		13.81%	13.81%	3.45%	811	
1989								-14.82%		6.37%	1.98%	-4.70%	-12.42%	958

* Actual demands are shown in bold.
** (Forecast - Actual) / Actual
Source: Data provided by BEPC, summer 1990.

FIGURE 3.18
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
TEXAS UTILITIES ELECTRIC COMPANY

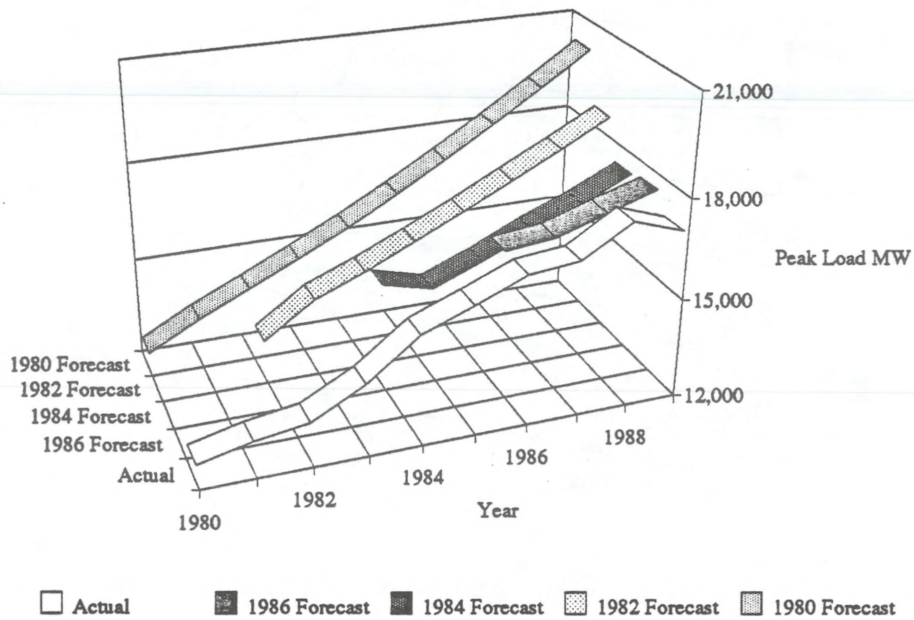


FIGURE 3.19
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
HOUSTON LIGHTING AND POWER COMPANY

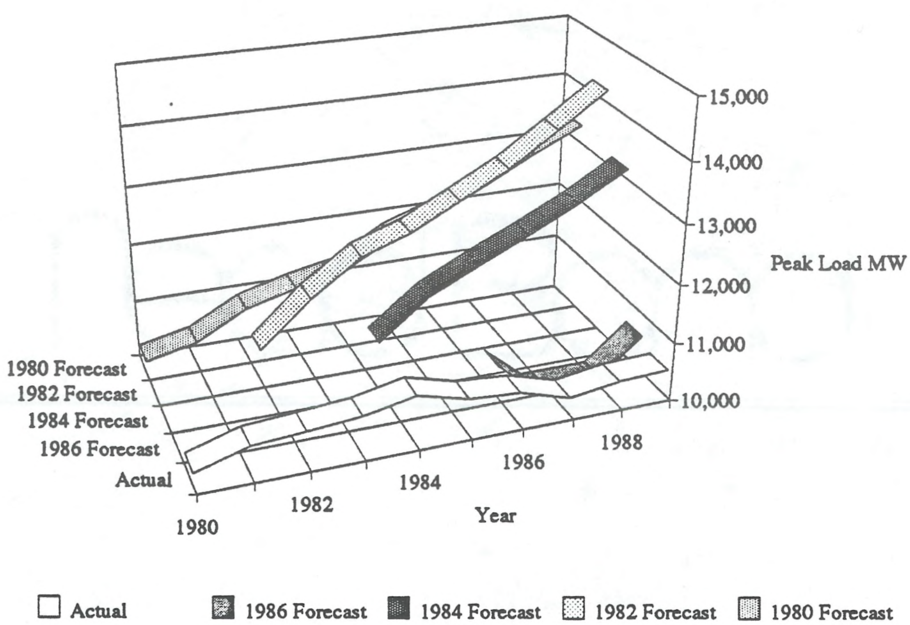


FIGURE 3.20
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
GULF STATES UTILITIES COMPANY

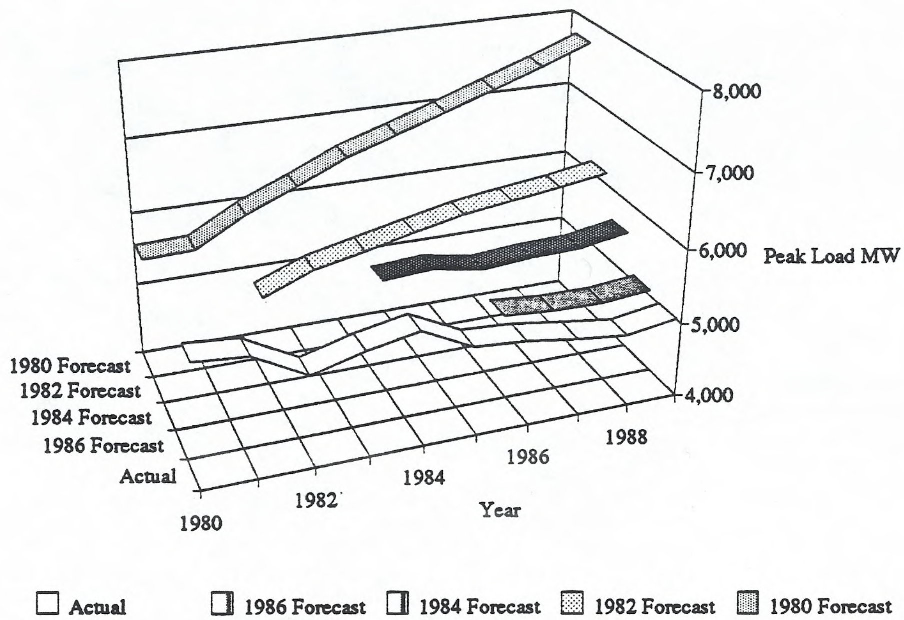


FIGURE 3.21
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
CENTRAL POWER AND LIGHT COMPANY

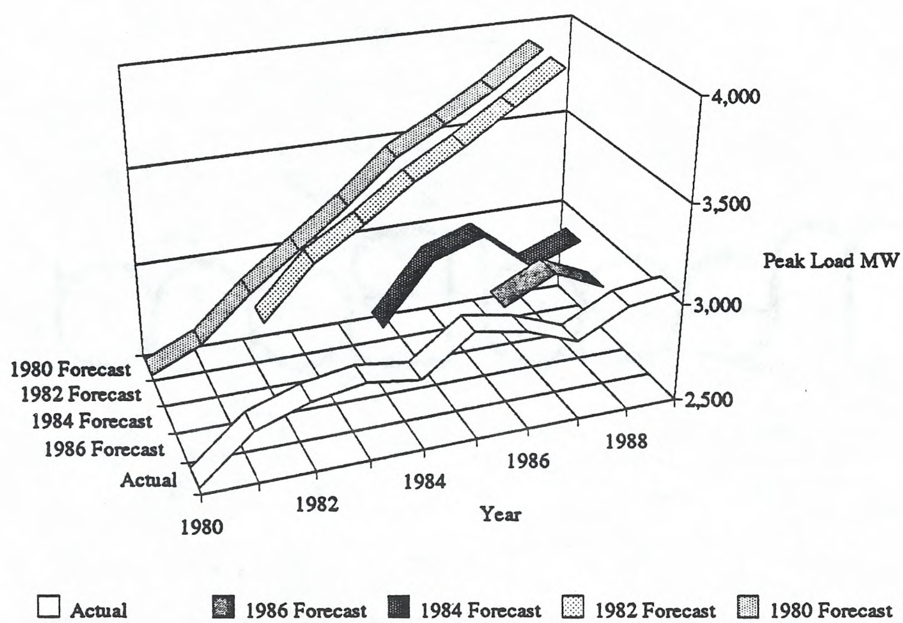


FIGURE 3.22
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
CITY PUBLIC SERVICE BOARD OF SAN ANTONIO

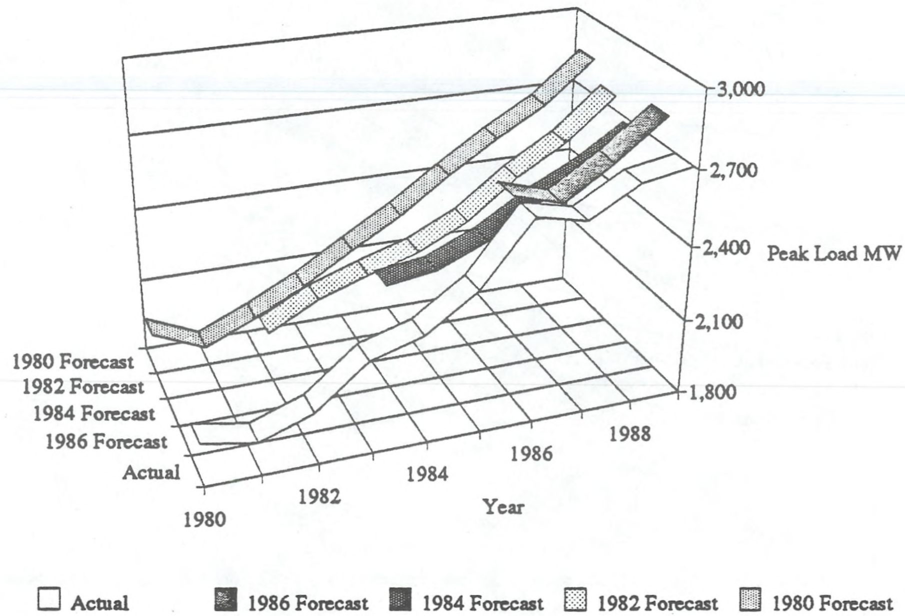


FIGURE 3.23
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
SOUTHWESTERN PUBLIC SERVICE COMPANY

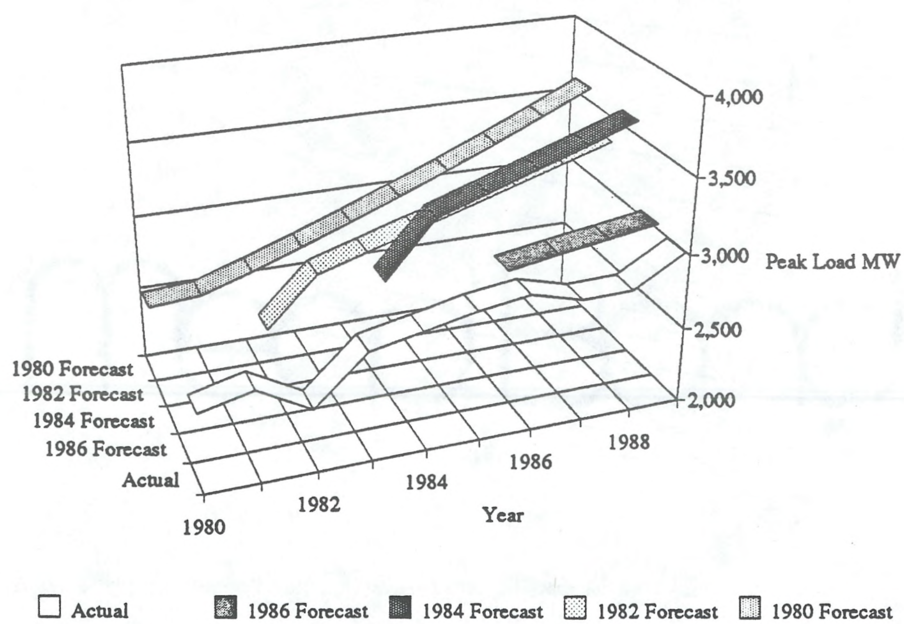


FIGURE 3.24
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
SOUTHWESTERN ELECTRIC POWER COMPANY

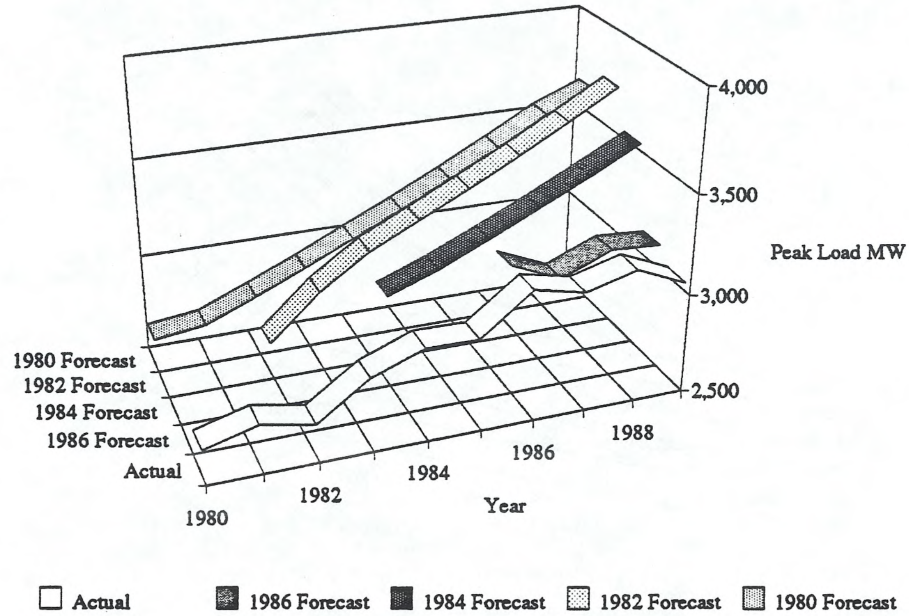


FIGURE 3.25
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
LOWER COLORADO RIVER AUTHORITY

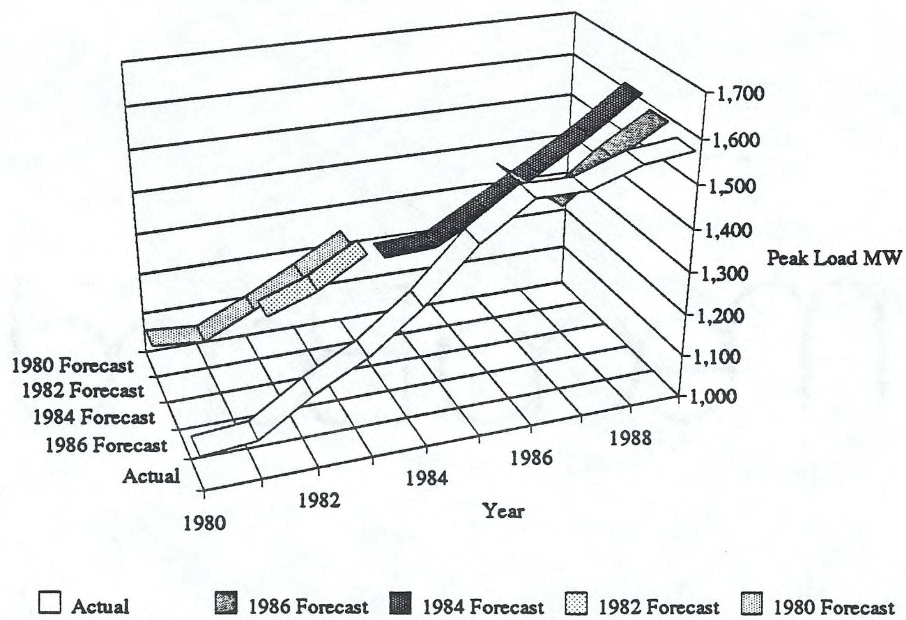


FIGURE 3.26
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
CITY OF AUSTIN ELECTRICITY UTILITY

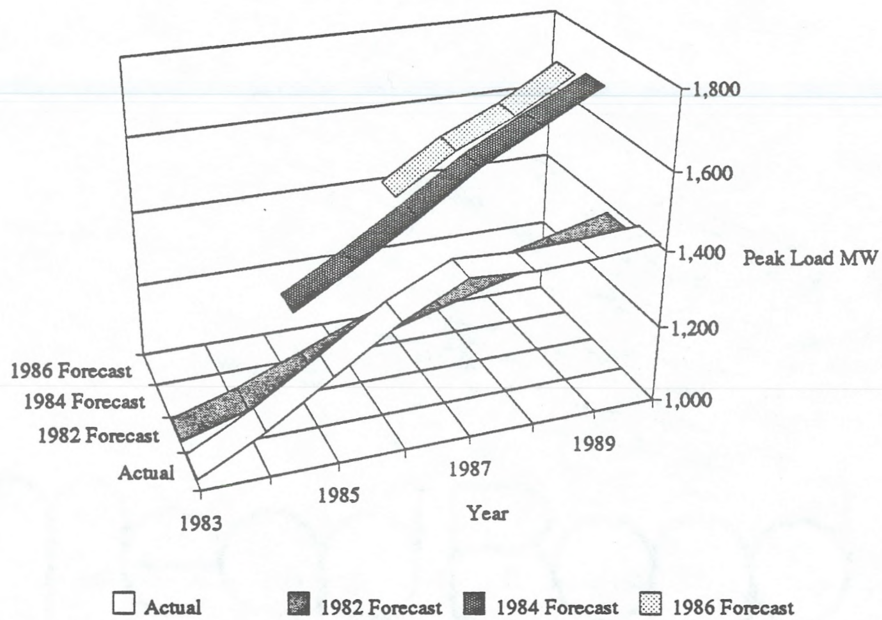


FIGURE 3.27
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
WEST TEXAS UTILITIES COMPANY

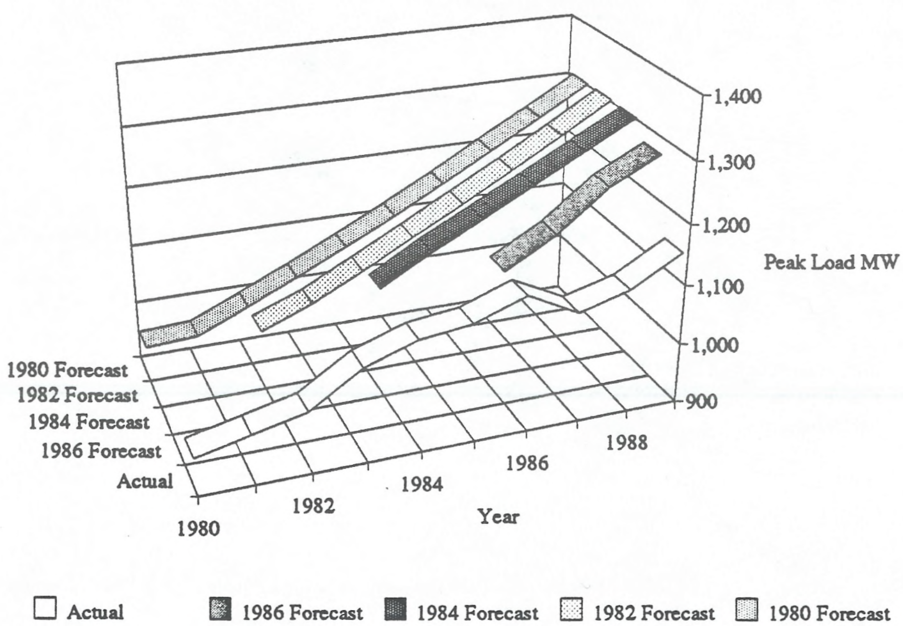


FIGURE 3.28
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
EL PASO ELECTRIC COMPANY

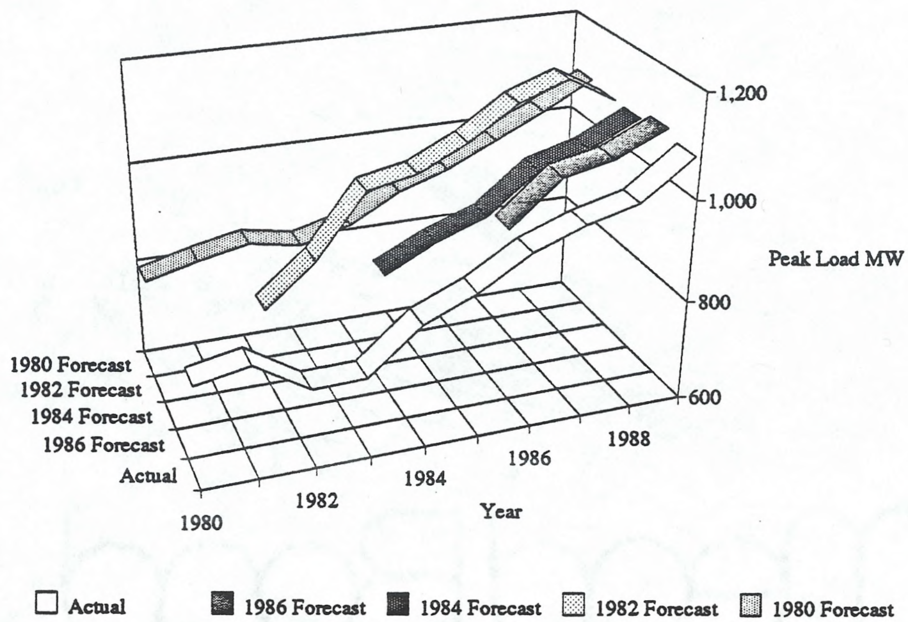


FIGURE 3.29
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
TEXAS - NEW MEXICO POWER COMPANY

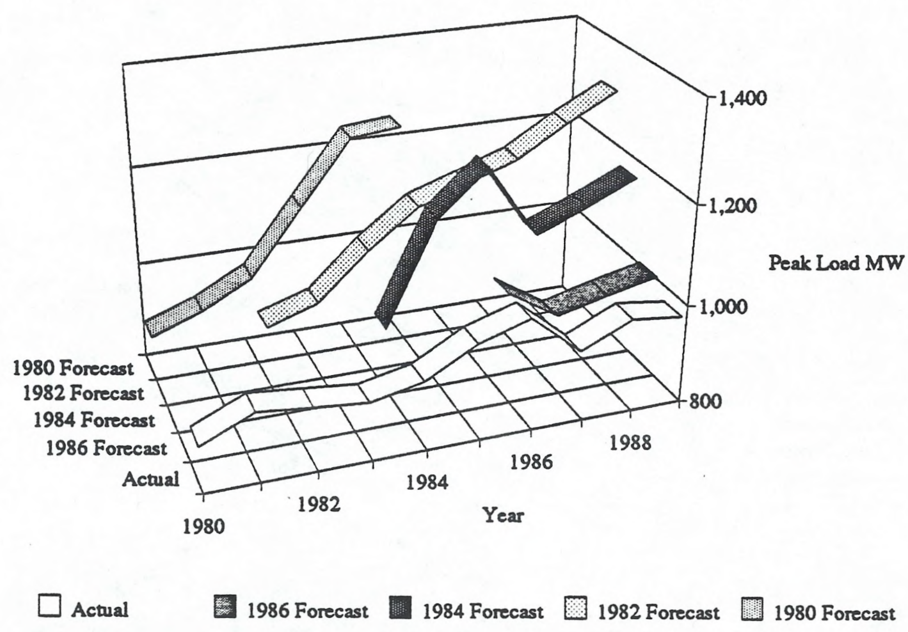
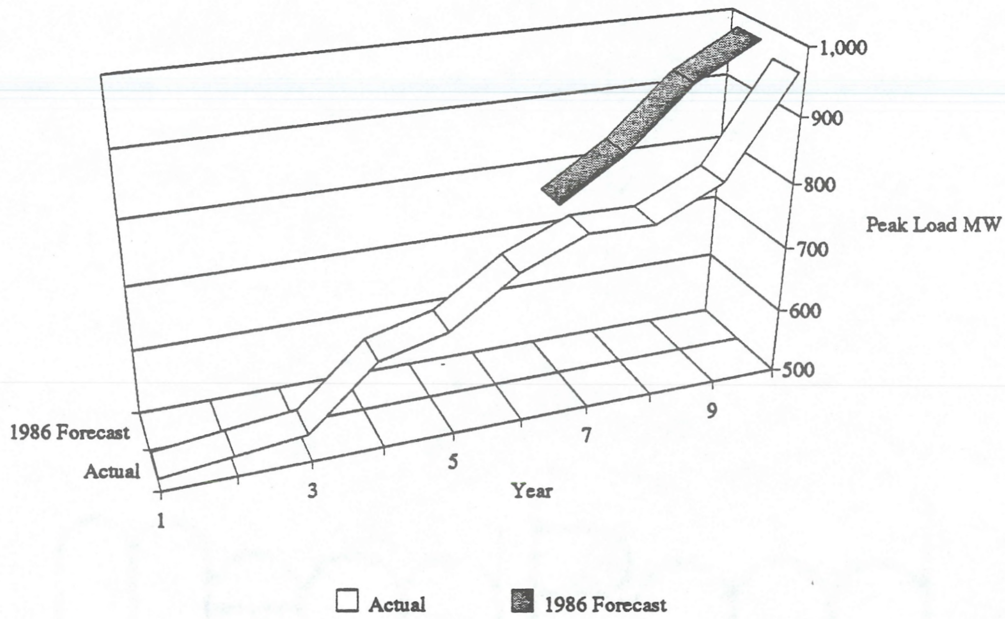


FIGURE 3.30
UTILITY-PROJECTED PEAK DEMAND VS. ACTUAL
BRAZOS ELECTRIC POWER COOPERATIVE, INC.



Chapter Four

SPECIAL TOPICS IN THE ELECTRIC INDUSTRY

Strategic Rate Design as a Resource Option

There is an emerging recognition that rate design can be used as a powerful resource planning tool. The structure, levels of charges, and terms and conditions of various rate offerings can have a significant impact on the quantity of electricity consumed as well as the time patterns of electricity consumption. Rate design, then, can be considered a resource planning tool because it affects consumption patterns which, in turn, influence supply options and requirements for a power supplier. Rate design can be used as a resource option in the context of active demand-side management (interruptible rates for example), passive demand-side management (time-of-day rates to encourage load shifting, for example), or installed capacity (payments to qualifying facilities).

Rate Design Approaches

A large variety of rate design strategies have been developed by utilities in pursuit of such diverse (and often conflicting) objectives as economic efficiency, fairness, conservation, promotion of use, subsidization, predation, low-income assistance, cogeneration promotion or discouragement, and competition. Electricity supply costs vary temporally and geographically. Rate designs of varying complexity can be used to track these cost variations and pursue these objectives. Some examples of such rate designs are:

1. Blocked KWH rates
2. Seasonally-differentiated rates
3. Marginal cost-based rates (including time-of-use rates)
4. Real-time or spot-market pricing
5. Priority pricing

Blocked KWH rates are rates that vary among different "blocks" of KWH consumption. Blocked rate structures are usually only a crude approximation of cost variations, since these rates are fixed over time.

Seasonally-differentiated rates imply that a different rate is charged for KWH consumption or KW demand during different seasons of the year. The price signal sent to consumers is more precise than would be received through a blocked rate because some time-variation in costs is recognized. Many utilities in Texas combine the use of seasonally-differentiated and blocked rates in their residential rate design. As shown in Table 4.1, some blocks of consumption during the off-peak season of the year are priced at a rate less than that charged for summer consumption. Seasonally- and block-differentiated rates are relatively inexpensive to implement as there is no need of extra metering equipment beyond the existing watt-hour meter.

Time-of-day (TOD) rates tend to send more precise price signals to consumers than non-time-differentiated approaches. During periods when the utility's operating and capacity costs tend to be higher, (for example, summer afternoons), electricity is priced at a premium. Electricity purchased during off-peak, low-cost periods is available at lower prices. Such pricing strategies provide incentives for consumers to shift consumption from periods of the day where the utility's operating costs are high and capacity constraints are approached, to periods where baseload plants are the marginal generating units. TOD pricing does, however, involve more metering and administrative costs than the seasonal- and blocked-rate strategies.

A natural extension of traditional marginal cost pricing approaches, such as seasonally-differentiated rates and TOD pricing, is **real-time or spot-market pricing.** While seasonally-differentiated rates and TOD pricing approaches provide the consumer with a simple schedule of prices based on average patterns in utility costs, real-time pricing provides for a much more exact relationship between costs and prices. Hourly price quotes might be announced to the consumer a day in advance via cable television or other electronic avenues. Prices are based upon the utility's expected operating costs for the following day given weather forecasts, anticipated operating unit availability, and other factors. Curtailment premiums would be expected to be assessed to encourage consumption abatement during periods of insufficient generating or transmission capacity.

TABLE 4.1

Residential Rate Structures in Texas for Major Utilities
as of November 1990

Utility	Customer Charge	Residential Service Energy Charge ($/KWH)	Residential Space Heating Rider ($/KWH)
TU Electric*	$6.00	Summer Charge (May - Oct.) i) All KWH: $.0548 Winter Charge (Nov. - April) i) 0 to 600 KWH: $.0548 ii) Beyond 600 KWH: $.0265	
HL&P	$6.00	Summer Charge (May - Oct.) i) 0 to 250 KWH: $.02040 ii) Beyond 250 KWH: $.068411 Winter Charge (Nov. - April) i) 0 to 250 KWH: $.02040 ii) 251 to 1,000 KWH: $.068411 iii) Beyond 1,000 KWH: $.031609	
GSU	$7.00	Summer Charge (May - Oct.) i) All KWH: $.05204 Winter Charge (Nov. - April) i) 0 to 1,000 KWH: $.05204 ii) Beyond 1,000 KWH: $.03204	
CPL*	$7.02	Summer Charge (April - Sept.) i) All KWH: $.0456 Winter Charge (Oct. - March) i) All KWH: $.0381	Winter Charge (Oct. - March) i) 0 to 800 KWH: $.0381 ii) Beyond 800 KWH: $.0231
SPS	$4.66	i) All KWH: $.0393	Winter Charge (Nov. - May) i) 0 to 500 KWH: $.0393 ii) Beyond 500 KWH: $.0086
SWEPCO	$7.00	Summer Charge (May - Oct.) i)All KWH: $.0453 Winter Charge (Nov. - April) i) 0 to 600 KWH: $.0352 ii) 601 to 2500 KWH: $.0203 iii) Beyond 2500 KWH: $.0352	
LCRA	$7.50	i) All KWH: $.03626	

TABLE 4.1 (continued)

Residential Rate Structures in Texas for Major Utilities as of November 1990

Utility	Customer Charge	Residential Service Energy Charge ($/KWH)	Residential Space Heating Rider ($/KWH)
COA	$3.00	Summer Charge (May - Oct.) i) 0 to 500 KWH: $.0235 ii) Beyond 500 KWH: $.0511	
		Winter Charge (Nov. - April) i) 0 to 500 KWH: $.0235 ii) Beyond 500 KWH: $.0411	
WTU	$6.50	Summer Charge (May - Oct.) i) All KWH: $.0572	
		Winter Charge (Nov. - April) i) All KWH: $.0472	Winter Charge (Nov. - April) i) 0 to 500 KWH: $.0472 ii) Beyond 500 KWH: $.0297
EPE	$4.00	Summer Charge (June - Sept.) i) All KWH: $.0702	
		Winter Charge (Oct. - May) i) All KWH: $.0652	Winter Charge (Nov. - April) i) 0 to 800: $.0652 ii) Beyond 800 KWH: $.0552
TNP*	$7.25	Summer Charge (May - Oct.) i) All KWH: $.07702	
		Winter Charge (Nov. - April) i) All KWH: $.07202	
SESCO**	$7.50	Summer Charge (May - Oct.) i) All KWH: $.06505	
		Winter Charge (Nov. - April) i) 0 to 800 KWH: $.06505 ii) Beyond 800 KWH: $.0492	

* Bonded rates

** Southwestern Electric Service Company. SESCO is the only investor-owned utility in Texas (of 10 total) which does not generate electricity.

TABLE 4.2

UTILITY ESTIMATES AND PROJECTIONS OF THE
IMPACT OF INTERRUPTIBLE RATE PROGRAMS
ON CAPACITY REQUIREMENTS
(MW - Texas Only)

	1990	2000
HL&P	1,061	746
TU Electric	292	471
CPL	185	306
GSU	59	63
SWEPCO	45	45
SPS	17	17
TNP	2	2
CPS	0	0
TOTAL	1,661	1,650

Note: The amounts reported represent the portion of the total contracted interruptible load which the utility considers available at the time of system peak.

A well-designed real-time pricing program is likely to have the same general impact on consumption behavior and resource requirements as a traditional TOD program. However, by maintaining a better relationship between costs and prices, the potential benefits can be much greater. Although achieving greater economic efficiency, real-time pricing may sacrifice the predictability of prices that consumers are accustomed to under the alternatives discussed above. Also, the costs of demand metering and communications devices tend to reduce the efficiency gains.

Priority pricing, a rate design strategy that is related to real-time pricing, is also designed to promote economic efficiency. Under priority pricing, electric service would be unbundled into a number of priority or reliability classes. The price of service taken under each of the priority classes would be related to the cost of providing the associated level of reliability. In the event of a capacity shortage, customers' load increments would be interrupted based on the customers' selections. Common interruptible rates, where the customer selects a lower level of reliability in return for a price discount, provides a limited example of priority pricing. Large scale implementations of priority pricing have not yet been attempted. There is concern that the "obligation to serve" doctrine might be violated under such practice.

Strategic Rate Design in Texas

This section discusses specific rate design programs which have been used in Texas to affect future utility generating resource requirements.

Interruptible rates. Under an interruptible rate tariff, the customer receives power at a lower price, but at a lower level of service reliability. For the utility, interruptible service may provide a means of reducing capacity requirements or stabilizing system frequency. Many large utilities in Texas offer interruptible rate tariffs. Moreover, the Commission's Substantive Rule 23.66(j) requires utilities to offer interruptible service to a requesting qualifying facility. During peak demand periods, service to interruptible customers may be curtailed. Thus, there is usually little, if any, need for the utility to construct generating capacity to meet the needs of these customers.

If the interruptible rate is instantaneous (that is, if the customer's service is automatically curtailed when system frequency dips below a certain level), the interruption may assist in restoring frequency to an acceptable level. Under some circumstances, instantaneously interruptible load may also permit the utility to reduce its spinning reserve requirements. Spinning reserve is the amount of capacity on-line and capable of serving load, above the amount needed, at a given instant.

As indicated in Table 4.2, most of the large generating utilities in Texas serve a portion of their large industrial customer load under interruptible rates. Combined, these utilities reduced their capacity requirements by over 1600 MW in 1990 through their interruptible rate programs. The designs of interruptible rate programs vary considerably among these utilities.

TU Electric offers "instantaneous interruptible" service to its large industrial customers. Service to the customer is curtailed by interrupt devices at the customers' sites whenever frequency at the customer's point of service dips below 59.7 Hz. Such a frequency dip usually occurs when the capacity on-line is insufficient to meet the demand on the system at that time. This might result from a system peak or an outage of a large generating unit.

HL&P now offers a number of classes of interruptible service, including: IS-30, where the customer is required to curtail service within 30 minutes of notification; IS-10, where 10 minutes notice is provided to the customer; and IS-I, a new instantaneous interruptible service similar to TU Electric's. HL&P projects declining use of their interruptible service over time as reserve margins decline and curtailments increase in frequency. Future use of interruptible service will also be affected by the status of the utility's cogeneration contracts, self-generation activity, the differential between the prices of firm and interruptible service, and changes in tariff terms and conditions.

CPL's IS-B rate is similar in design to HL&P's original IS-B rate. Customers are provided 15 minutes notice when a service interruption is deemed necessary.

GSU offers interruptible rates with 30 and 5 minute notice requirements, and has recently proposed a no-notice or instantaneously interruptible rate.

CPS offers an instantaneously interruptible rate; but makes no adjustment to its demand forecast for the impact of this rate. CPS considers the purpose of this rate to be for spinning reserve requirements, rather than for shaving. Three customers with a total contract load of around 10 MW are presently on this rate.

SWEPCO considers its interruptible rate impacts embedded in its forecast of peak demand.

Real-Time Pricing. Several utilities in Texas have either conducted real-time pricing experiments or have implemented real-time pricing in a limited way.

HL&P's IS-B rate, a predecessor to the current IS-I and IS-10 tariffs, served between ten and fifteen large industrial customers between 1985 and 1987. Most of these customers also took service under one of the utility's firm rates, and many also had their own generating capability which they could rely upon in the event of an interruption or anticipated high prices. Prices were determined by hourly system marginal costs calculated by the Company's GENSOM production costing model. A problem with this rate was that the customers did not know the exact prices they were facing until after the fact (the marginal cost calculations were made ex ante). Distrust of the utility's marginal cost calculations motivated changes in the structure of this rate. In 1987, this was modified into a more traditional time-of-use rate. However, the idea of basing HL&P's new interruptible rates on real-time pricing concepts is now being explored again.

Two large industrial customers now take service under CPL's IS-B rate. Similar to HL&P's original IS-B rate, the hourly prices quoted under this interruptible rate reflect the utility's hourly marginal costs.

Faced with declining demand in its service area since 1980, increasing cogeneration activity, and financial constraints brought about by the Company's investment in River Bend Nuclear Plant and other factors, GSU has recently established a real-time differentiated interruptible rate for industrial customers that have their own on-site generation capability. The Experimental Economic As-available Power Service rate is designed to encourage new sales to large industrial firms that previously satisfied their power requirements with their own generation. At times when GSU's system marginal cost is below the marginal cost associated with the firm generating its own power internally, the firm would have an incentive to purchase from the utility. While the customer receives hourly price forecasts by telephoning the system operator one hour in advance, the actual prices charged are based upon an ex ante calculation of the actual marginal costs incurred.

While GSU anticipated considerable interest in this rate, only one customer has signed up during its first year of availability. It appears that many potential customers lacked the technical sophistication needed to calculate their own marginal costs and determine the difference between their costs and the utility's hourly price forecast.

CPL is presently investigating opportunities for effective real-time pricing in the commercial sector.

Conclusions Strategic rate design may be employed as a resource planning tool. It can serve as a means of reducing system capacity requirements, facilitating the implementation of demand-side management efforts, or securing capacity.

In their current forecasts, the State's utilities have reduced their peak demand forecasts by 1,603 MW in the year 2000 for interruptible service programs. The Commission staff has evaluated these projections and generally recommends their adoption as adjustments to the Commission staff's peak demand forecast. A further discussion is provided in Chapter 5.

For other strategic rate design programs offered by the state's utilities, there has been a reluctance to adjust load forecasts for their potential impact. In some cases, the participation rates in these programs in Texas has been too low to warrant an adjustment. For example, time-of-day rates have not been widely accepted in Texas. The impact of some other rate programs are already embedded in demand projections, and thus no post-modelling adjustment is warranted. This may be true of some seasonally-differentiated or blocked rates that have been in existence in Texas for some time. Finally, customer behavior under some other programs, including real-time pricing, may not yet be sufficiently understood to permit the quantification of an adjustment to demand.

Strategic rate design holds further promise as a resource planning tool. The Commission staff will continue to analyze the impact on resource planning objectives of rate design changes, and strive toward better understanding the impact of rate design changes on customer behavior and system capacity requirements.

Environmental Issues

Environmental Policy Act In July 1989, the Bush Administration announced its proposed amendments to the Clean Air Act. The amendments were introduced, respectively, into the U.S. House of Representatives and the U.S. Senate as H.R. 3030 and S. 1490. Compromise legislation was developed and in November 1990 was signed into law by the President.

The amendments are a comprehensive plan to reduce sulfur dioxide (SO_2), nitrogen oxides (NO_x), ozone, and carbon monoxide from all emitting sources. This section, however, focuses only on the effects of the plan on electric utilities, and more specifically, how the plan affects Texas electric ratepayers.

The goal of the plan is to reduce SO_2 emissions by 10 million tons by the year 2000. An unusual aspect of the plan is the creation of emission allowances. Existing units will be issued allowances equal to the annual tons of SO_2 emitted, based on 1985 fuel consumption. The owner of new units will not be issued allowances but must otherwise obtain allowances equal to the tons of SO_2 to be emitted from the unit. These allowances may be self-generated by removing an existing unit from service or reducing a unit's emissions below required caps. The allowances may also be obtained by trade or purchase from another utility.

The plants generally at risk of high SO_2 emissions are older coal and lignite-fired plants that burn fuel containing a high percentage of sulfur but pre-date existing clean air requirements. In Texas, however, most power plants currently in service have been built more recently and many have already installed scrubbers to substantially reduce emissions of SO_2. All Texas coal and lignite-fired power plants meet the proposed first phase emissions limit of 2.5 lbs of SO_2 per MMBTU that is required by 1995. In fact, most Texas power plants generally meet even the tighter cap of 1.2 lbs of SO_2 per MMBTU by 2000 as required in phase two.

The passage of this clean air legislation will generate a great deal of uncertainty among utility planners. The most significant uncertainty, however, is the cost and availability of the proposed emission allowances. For a new plant to be put into service, sufficient credits must be obtained for the life of the plant. The question of prudence may be an issue if plants are constructed without the accompanying emission allowances.

If a utility cannot internally generate emission allowances, the alternative will be to obtain allowances from out of state. The result of this will be reliance on other states' utilities to reduce emissions sufficiently below the cap so that excess credits will be made available. At the same time, the utility that generates credits will need to bank credits to insure its own future growth. Only a limited number of credits are planned to be available from a federal emissions credit "bank". If sufficient excess credits are not generated, the law of supply and demand dictates that the price of the few available credits will be prohibitive. Further, a state utility commission may prohibit the sale of any credits out of state to insure adequate growth in state.

Pollution Control Power plant operation produces various types of combustion residuals and other waste material that must be disposed in an environmentally safe manner according to Federal and state laws. The waste material includes ash particles that are emitted in the flue gas and collected in some fashion for disposal. Boiler slag and sludge from flue gas desulfurization systems are also produced in solid fossil fuel plants. Ponds and dumps must be installed for the disposal of this material. In the generation of electric power, water is discharged and must be treated for impurities in order to reuse the water or discharge it into natural drainages.

The utilities in the state have plans to spend over $12 million through 1995 to improve the control of waste material in and around existing electric power plants. The facilities and cost estimates were developed by the utilities considering the existing laws, rules, and regulations.

For future plants, the control of pollution becomes more extensive. Large new lignite-fired generating units will require major investments in excess of one billion dollars to meet the existing laws for air, water, and solid pollution control.

The generating utilities in Texas are concerned about the potential cost and implementation of the 1990 amendment to the Clean Air Act. Most Texas power plants are already within the emissions limits of the amendments. Texas utilities have invested heavily in reducing emissions so that there will be very little initial cost to come into compliance with the new legislation. They are concerned, though, that because Texas is already a low emitting state, there is little flexibility within Texas to generate allowances for future growth. The amendments require that emissions from future plants will need to be fully offset by emission reductions from existing facilities of the constructing utility or purchased from other utilities that have reduced emissions. The additional expense, in either case, has not been quantified by the utilities and will not be until the legislation is implemented.

Energy Fuels and Environmental Management Over the next decade, the United States will need as much as 150,000 MW of new generating capacity to meet increased demand and replace older, less efficient units. To place this new capacity into perspective, $100 billion in capital financing will be required, as well as some $200 billion in long-term fuel supply. Energy policy makers must anticipate the long-term social costs (environmental and health) associated with these large scale projects.

One problem in dealing with environmental issues is that there is intense conflict over how to do it and at what cost to taxpayers, business, and national economic interests. Delaying a response will be costly. Leading scientists acknowledge that the risks of global warming are sufficiently clear to merit immediate action.

Coal and uranium are the primary fuel sources for large electrical power plants. Coal remains the dominant fuel for electric generation because of its relatively low cost and domestic abundance. Moreover, after the incident at Three Mile Island in 1979 and the more recent Chernobyl accident, utilities have moved away from building nuclear power plants. Both of these fuel sources contribute to environmental concerns, such as acid rain or radioactive waste disposal.

The United States possesses approximately 268 billion tons of mineable coal which would supply the nation's energy and industrial requirements for 250 years. Unless the undesirable emissions from coal-fired power plants are controlled, however, the effects on the global environment will be significant. For example, acid rain results from the reaction of SO_2 and NO_x, water vapor, and other chemicals, including oxidants, which are the primary products of the combustion of fossil fuels such as petroleum products and coal.

Various clean coal technologies such as coal conversion, gasification, liquefaction, cleaning, and coal co-firing with oil or natural gas, along with combustion techniques that utilize Best Available Control Technology (BACT) are in use today to meet the stringent requirements of environmental and clean air regulations.

The fuel which powers a nuclear reactor is composed of uranium oxide pellets sealed in a metal tube bundled into fuel assemblies. Once the fuel in a nuclear reactor no longer contributes efficiently to the nuclear chain reaction, it is considered "spent". The spent fuel is temporarily stored at the power plant before being moved to permanent storage facilities elsewhere. However, some spent fuel has been held in temporary storage for more than 30 years.

The goal of the United States nuclear waste management program is to develop a permanent disposal method that poses no significant threat to people or the environment now or in the future. The program has selected a permanent repository in the State of

Nevada. However, there have been delays in developing the repository. The State of Nevada has recently refused to grant the necessary environmental permits for initial site investigation at the proposed depository. The DOE has now announced that the Nevada repository will not be open before the year 2010.

It is important to balance energy use and a clean, healthy environment. Policy makers cannot afford to overlook or ignore the factors that affect people and the environment, but at the same time must also recognize the implications of the growing demand for energy.

CHAPTER FIVE

DEMAND-SIDE RESOURCES

Introduction

Demand-side resources have a significant potential to economically reduce the energy and peak-demand requirements of the state's major generating utilities. Several electric utilities in Texas have found that they can defer capacity, reduce electric generation at critical periods, and satisfy other corporate goals with conservation and load management programs.

Summary of Demand-side Adjustments

This chapter presents the Commission staff forecast of demand-side resources. The demand-side adjustments to the "raw" peak-demand and sales forecasts fall into three categories:

1. Exogenous factors
2. Active demand-side management
3. Passive demand-side management

Exogenous factor adjustments include the effects of laws and customer actions beyond the control of the utility. Active and passive demand-side management (DSM) adjustments include the effects of utility-sponsored programs not reflected in the "raw" econometric forecasts.

During the review process, staff examines the adjustments to peak-demand submitted by the utilities. These adjustments are accepted as submitted if they are reasonable and documented. Otherwise, an independent set of adjustments is prepared based on the program design and efficiency levels and the capabilities and intentions of the state's utilities. Later sections in thie chapter provide an explanation of the adjustments adopted for each service area. Tables 5.1 and 5.2 display the adjustments made to the forecast on a statewide basis where only the Texas portion of GSU, SPS, SWEPCO, and EPE are included. The peak-demand adjustments are presented by category: exogenous factors, active DSM, and passive DSM. The energy adjustments are presented by customer class. Tables 5.3 and 5.4 include total system impacts.

A Comparison of Past and Current Demand-side Adjustments

The Commission's 1984 Forecast did not include an independent assessment of the economic potential for conservation and load management programs. In contrast, the 1986 forecast included a staff review of conservation literature, the activities of other state commissions and utilities, and the Energy Efficiency Plans filed in Texas to arrive at an estimate of the impact of conservation and load management over the 1986 to 1995 period. The report adopted by the Commission included the staff's recommended achievement of a 12-percent peak-demand reduction in each utility service area by 1995.

In the **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas 1988,** Commission staff presented independent projections of utility activities on a program-by-program basis. Those adjustments reflected the impact of current programs plus the impact of structural efficiency programs not then in place.[1] Structural efficiency programs were identified by staff as a critical source of peak-demand savings which, if not implemented at the time of construction, would otherwise be lost from the utility resource plan.

In the current forecast, Commission staff has again conducted an independent program-by-program review. The purpose of the review is to establish an estimate of the impact of the activities not reflected in the staff's "raw" econometric forecast. These demand-side adjustments represent the likely impact of exogenous factors and demand-side management based on the present capabilities and intentions of the state's utilities. Unfortunately, only a few utilities have modified their Energy Efficiency Plans during the past two years to include or improve structural efficiency programs. Therefore, the potential impact of programs not presently offered or planned was not taken into account.

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1 The structural efficiency of customer buildings can be improved by reducing heat loss in the winter and heat gain in the summer through the use of increased insulation, window treatments, or site planning.

TABLE 5.1
DEMAND SIDE ADJUSTMENTS
TEXAS SYSTEMS
1990 - 2000
(MW)

Year	Exogenous	Active DSM	Passive DSM	Total
1990	96	1,572	99	1,767
1991	139	1,399	236	1,774
1992	184	1,442	375	2,000
1993	259	1,570	501	2,329
1994	334	1,612	638	2,585
1995	392	1,670	809	2,871
1996	449	1,796	970	3,215
1997	497	1,876	1,134	3,507
1998	547	1,955	1,303	3,805
1999	547	2,032	1,470	4,049
2000	547	2,102	1,635	4,284

Note: MW are at the point of generation.

TABLE 5.2
DEMAND SIDE ADJUSTMENTS
TEXAS SYSTEMS
1990 - 2000
(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1990	327,854	30,937	(489)	0	358,302
1991	486,577	154,767	1,214	0	642,558
1992	657,258	306,010	5,890	0	969,158
1993	840,017	423,731	6,139	0	1,269,887
1994	1,024,314	543,106	6,256	0	1,573,677
1995	1,221,122	699,444	9,475	0	1,930,041
1996	1,422,962	874,466	14,329	0	2,311,757
1997	1,589,761	1,057,238	19,021	0	2,666,020
1998	1,758,985	1,250,600	24,367	0	3,033,952
1999	1,862,439	1,453,080	29,921	0	3,345,440
2000	1,956,747	1,664,767	36,017	0	3,657,531

Note: MWH are at the customer meter.

TABLE 5.3
DEMAND SIDE ADJUSTMENTS
TOTAL SYSTEMS
1990 - 2000
(MW)

Year	Exogenous	Active DSM	Passive DSM	Total
1990	88	1,613	99	1,800
1991	135	1,422	236	1,793
1992	184	1,465	375	2,023
1993	263	1,593	501	2,356
1994	343	1,635	638	2,617
1995	406	1,693	809	2,908
1996	466	1,819	970	3,255
1997	518	1,899	1,134	3,551
1998	570	1,978	1,303	3,851
1999	570	2,067	1,470	4,107
2000	570	2,137	1,635	4,342

Note: MW are at the point of generation.

TABLE 5.4
DEMAND SIDE ADJUSTMENTS
TOTAL SYSTEMS
1990 - 2000
(MWH)

Year	Residential	Commercial	Industrial	Other	Total
1990	349,537	30,937	(489)	0	379,985
1991	514,651	154,767	1,214	0	670,632
1992	691,725	306,010	5,890	0	1,003,625
1993	882,485	423,731	6,139	0	1,312,355
1994	1,074,782	543,106	6,256	0	1,624,145
1995	1,277,447	699,444	9,475	0	1,986,366
1996	1,485,139	874,466	14,329	0	2,373,934
1997	1,656,373	1,057,238	19,021	0	2,732,632
1998	1,830,031	1,250,600	24,367	0	3,104,998
1999	1,933,485	1,453,080	29,921	0	3,416,486
2000	2,027,793	1,664,767	36,017	0	3,728,577

Note: MWH are at the customer meter.

Inclusion of a forecast adjustment for a DSM program does not imply that program expenses are allowable in the cost of service. The absence of estimates of the potential impact of particular conservation programs does not necessarily reflect the Commission's position on these programs. The Commission staff will continue to examine the need for conservation programs as called for in regulatory proceedings.

As this chapter is reviewed, those familiar with past Commission forecasts will notice the following changes:

1. Adjustments reflecting the likely impacts of the National Appliance Energy Conservation Act of 1987 are presented for each major service area
2. Both peak-demand and annual energy impacts have been prepared for each adjustment
3. An estimate of the impact of standby customers on resource planning is presented for HL&P, CPL, and GSU
4. The impact of each DSM program has been more critically assessed

Summary of Energy Efficiency Regulatory Issues

The 1983 amendments to the Texas Public Utility Regulatory Act (PURA) make explicit the role of conservation to reduce the need for new generating capacity in Texas. As the review of current Energy Efficiency Plans has progressed it has become apparent that only four of the state's major utilities have recognized and are acting upon the potential for conservation and load management programs to reduce peak-demand. Their activities may be briefly summarized as follows:

1. TU Electric has reduced peak demand by nearly 1,000 MW in ten years and has stated that additional savings will be achieved each year
2. HL&P reduced peak demand by 200 MW in the early 1980s. After four years of sales promotion, the Company has recently indicated that it was launching a renewed peak-demand reduction program
3. COA plans to reduce peak demand by more than 500 MW. While slow demand growth has limited the city's potential achievements to date, a full menu of program options is offered to commercial and residential customers
4. LCRA plans to reduce peak-demand growth by 200 MW through efficiency and direct load control programs. The Authority has recently reorganized to improve program implementation and evaluation

None of the state's other large utilities have a comprehensive set of programs, a high rate of program participation, or an approach to the conservation of resources which can be termed aggressive. Although several good programs can be identified most of these utilities focus on increasing sales during off-peak periods, encouraging customers to use electric appliances instead of natural gas appliances, and operating conservation programs at a level which will merely satisfy the perceived regulatory requirement.

While staff has not prepared specific recommendations to encourage the energy efficiency of electricity usage in Texas, the following observations are offered:

1. Two utilities (EPE, BEPC) which anticipate the addition of new generating plants by the mid-1990s have made little, if any, progress in implementing DSM programs
2. HL&P anticipates the addition of new generating plants by the mid-1990s and is now apparently moving to implement peak-reducing DSM programs. However, HL&P's activities may be "too little, too late" to affect its capacity resource plan
3. The largest municipal utility in Texas, CPS, is anticipating the addition of several new generating stations during the forecast period but CPS has recently decided to end several significant conservation programs
4. Several of the state's major utilities continue to use DSM programs to influence major appliance purchase decisions in order to increase sales. This remains an obstacle to energy efficiency goals, particularly in light of recent Commission decisions regarding the promotion of electricity sales and the encouragement of average efficiency appliances

Background

Definitions The information provided here includes definitions for common conservation terms. Highlighted are demand-side management (DSM), conservation and load management, active and passive DSM, and load shape objective terminology.

Demand-side management is the set of utility-initiated programs intended to economically alter customer's energy usage patterns. DSM programs are distinct from the price-induced conservation which occurs without utility sponsorship or intervention.[2]

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[2] The Commission staff's "raw" econometric sales forecasts explicitly include price variables and thus price-induced conservation is reflected in the forecasts.

Demand-side management, as used here, has no connection with the personal deprivation or hardship sometimes associated with the word "conservation," although one may properly refer to some demand-side activities as conservation programs.

"Conservation", in general usage, refers to programs which reduce energy use *at any time*. But many conservation programs are "strategic" because they focus on energy efficiency improvements during peak-demand periods. Air conditioner efficiency programs are called *strategic conservation* because Texas' hot weather generally, and space cooling loads specifically, drive summer peak-demands.

Load management programs frequently focus on peak-demand reduction and may or may not include changes in energy usage. For example, load shifting from peak to off-peak periods may not change annual energy usage. Similarly, interruptions or delays in equipment operation may alter consumption only slightly.

The demand-side adjustments described in this chapter include exogenous factors, active DSM, and passive DSM. Exogenous factor adjustments include the effects of laws and customer actions beyond the control of the utility. Neither the impact of the federal appliance efficiency standards (the National Appliance Energy Conservation Act of 1987), nor the impact of self-generation and significant load growth, nor the actions of standby customers can be controlled by the utility. It is important, however, that the utility anticipate and forecast these events.

Active and passive DSM adjustments include the impact of the utilities' efforts to modify customer energy usage patterns. Active DSM is dispatchable and includes interruptible loads and appliance cycling programs that require a signal to a device or customer. Utility control may be direct (as in under-frequency relays for instantaneous interruptible loads), or indirect through telephone communication.

Passive DSM refers to programs that are not dispatchable. Passive DSM programs, by definition, must involve utility-initiated efforts; however, once implemented, the utility is a passive observer of the effects. Building insulation is a good example of the most passive energy efficiency measure: it is highly reliable, not subject to utility control, non-dispatchable (it is always in place), and essentially irreversible.

Throughout the 1980s, electric utilities supported the Electric Power Research Institute (EPRI) in its demand-side research. To the traditional load shape objectives of shaving peak, shifting peak, and off-peak sales promotion, EPRI has added strategic additions and reductions in load (to improve load-factor) and flexibility of load shape. Six load shape objectives encompass the universe of utility-initiated demand-shaping actions:

<u>Load Shape Objective</u>	<u>Example</u>
Peak Clipping (or shaving)	Appliance cycling by direct control such as LCRA's Air Conditioner Cycling Program.
Load Shifting	Nighttime "cool storage" such as TU Electric's Thermal Storage Program.
Valley Filling	Off-peak increases in sales such as security lighting programs or programs which encourage the replacement of natural gas furnaces with electric heat pumps.
Strategic Conservation	Equipment and structural efficiency programs which focus on peak period usage such as LCRA's Cooling Efficiency Program, TU Electric's Energy Action Programs, or Good Cents Home Programs which encourage structural efficiency and the installation of efficient air conditioners or heat pumps.
Strategic Load Growth	Electrification and economic development activities which increase usage at all times.
Flexible Load Shape	Interruptible loads which allow control of system load shape throughout the year.

Peak clipping, load shifting, strategic conservation, and flexible load shape are associated with reducing energy use or peak-demand. Valley filling and strategic load growth relate to increasing sales. DSM activities provide an expanded selection of electric service options for customers who desire to control their energy costs or modify their behavior to their advantage. (See Figure 5.1.)

FIGURE 5.1

LOAD SHAPE OBJECTIVES*

PEAK CLIPPING, or the reduction of the system peak loads, embodies one of the classic forms of load management. Peak clipping is generally considered as the reduction of peak load by using direct load control. Direct load control is most commonly practiced by direct utility control of customers' appliances. While many utilities consider this as a means to reduce peaking capacity or capacity purchases and consider control only during the most probable days of system peak, direct load control can be used to reduce operating cost and dependence on critical fuels by economic dispatch.

PEAK CLIPPING

VALLEY FILLING is the second classic form of load management. Valley filling encompasses building off-peak loads. This may be particularly desirable where the long-run incremental cost is less than the average price of electricity. Adding properly priced off-peak load under those circumstances decreases the average price. Valley filling can be accomplished in several ways, one of the most popular of which is new thermal energy storage (water heating and/or space heating) that displaces loads served by fossil fuels.

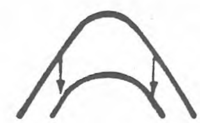
VALLEY FILLING

LOAD SHIFTING is the last classic form of load management. This involves shifting load from on-peak to off-peak periods. Popular applications include use of storage water heating, storage space heating, coolness storage, and customer load shifts. In this case, the load shift from storage devices involves displacing what would have been conventional appliances served by electricity.

LOAD SHIFTING

STRATEGIC CONSERVATION is the load shape change that results from utility-stimulated programs directed at end use consumption. Not normally considered load management, the change reflects a modification of the load shape involving a reduction in sales as well as a change in the pattern of use. In employing energy conservation, the utility planner must consider what conservation actions would occur naturally and then evaluate the cost-effectiveness of possible intended utility programs to accelerate or stimulate those actions. Examples include weatherization and appliance efficiency improvement.

STRATEGIC CONSERV-ATION

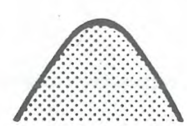


STRATEGIC LOAD GROWTH is the load shape change that refers to a general increase in sales beyond the valley filling described previously. Load growth may involve increased market share of loads that are, or can be, served by competing fuels, as well as area development. In the future, load growth may include electrification. Electrification is the term currently being employed to describe the new emerging electric technologies surrounding electric vehicles, industrial process heating, and automation. These have a potential for increasing the electric energy intensity of the U.S. industrial sector. This rise in intensity may be motivated by reduction in the use of fossil fuels and raw materials resulting in improved overall productivity.

STRATEGIC LOAD GROWTH

FLEXIBLE LOAD SHAPE is a concept related to reliability, a planning constraint. Once the anticipated load shape, including demand-side activities, is forecast over the corporate planning horizon, the power supply planner studies the final optimum supply-side options. Among the many criteria he uses is reliability. Load shape can be flexible — if customers are presented with options as to the variations in quality of service that they are willing to allow in exchange for various incentives. The programs involved can be variations of interruptible or curtailable load; concepts of pooled, integrated energy management systems; or individual customer load control devices offering service constraints.

FLEXIBLE LOAD SHAPE



*Adapted from Clark W. Gellings, Highlights of a speech presented to the 1982 Executive Symposium of EEI Customer Service and Marketing Personnel.

The Evolution of Demand-Side Activities

During the first few years of providing lighting services, Thomas Edison developed daytime loads to level out nighttime demands. Thus began electric utility involvement with the customer. Edison knew that electric lighting was a service rather than a commodity, therefore he billed for lighting services. He was aware that, in the future, a change from billing for lighting services to billing for kilowatt-hours (a commodity) would provide the manufacturers of lighting equipment the greatest benefit from technological improvements in light bulbs.[3]

As unit costs declined in the post-war period, electric utilities actively promoted electric sales. The saturation of electrically driven equipment increased dramatically. Americans 35 and older remember Reddy Kilowatt, Gold Medallion all-electric homes, "living better electrically," and electricity "too cheap to meter." Those slogans and programs were valid in their time. As the 1960s drew to a close, the driving themes in electric production shifted to reliability issues, environmental concerns, and a serious discussion of resource constraints.

The 1970s' oil price shocks brought gasoline lines, thermostat adjustments, and government programs to reduce consumption. Electric utilities diversified their fuel mix and initiated conservation programs. The results were dramatic as customers responded to price increases. Simple conservation measures reduced consumption with slight adjustments in industrial productivity or human comfort. While these short-term adjustments were necessary, the long-term energy supply outlook was more positive. Changes in the pricing of energy and improvements in equipment efficiency set the stage for the excess capacity the state is now experiencing.

The cost of new generating units took center stage by the start of the 1980s. Building on the conservation experiences of the 1970s, utilities began to systematically measure the changes in usage which resulted from conservation programs. Among the utilities wishing to slow the demand for new generating capacity, TU Electric and HL&P implemented programs which reduced their coincident peak-demands by over 20 MW each in 1981. TU Electric set a corporate goal to reduce peak-demand by 1,000 MW.

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3 This has occurred. Technological advances, such as high-pressure sodium lighting, allow only one-eighth the kilowatt-hour consumption for the same lumen output as standard (incandescent) lighting. Lighting manufacturers have benefitted from the sale of these products, while electric utilities continue to resist the loss of sales associated with energy efficiency.

The City of Austin initiated its celebrated "conservation power plant" program in 1983. Significant program participation at several utilities continued through the mid-1980s, primarily in air conditioner efficiency and structural efficiency programs.

Many effective DSM programs are now in place. Typically, these activities are administered from within utilities' marketing, conservation, or customer service departments. Approximately 100 programs are reported in the Energy Efficiency Plans filed with the Commission in December 1989. In addition, innovative rate designs and new customer technologies are under study at a few utilities.

In contrast to traditional forecasting and resource planning, the demand-side (customer-side-of-the-meter) approach puts emphasis on "end uses" of electricity, rather than on the aggregate usage of a class of customers. "End-use energy efficiency" thus refers to the technological efficiency of a particular device, whether light, pump, or air conditioner. Here, energy efficiency refers to the efficiency of usage within the customers' control, not the efficiency gains possible in the generation and transmission of electricity.

Efficient use of energy in customer-owned devices permits existing comfort levels, convenience, or productivity at a lower total-system cost. Conservation of resources may occur by reducing heat loss or gain in buildings, raising technical efficiency of electrically-driven equipment, or reorganizing processes to make use of waste heat. Technological innovations present a significant potential for efficiency improvements. For example, structural improvements in buildings can virtually eliminate the need for residential space heating in many parts of Texas. Integration of energy uses provides opportunities for increased efficiency because of the cascading effects of processes. Heat recovery from an air conditioner, for example, can turn waste heat into a source of heat for domestic hot water. In both industry and the home, the potential for energy efficiency increases as processes are redefined and as technologies improve.

DSM appears to be here to stay as utilities recognize the importance of studying and modifying customer behavior. The key to successful DSM is the customer. As the tools and techniques of DSM have evolved, professionals have borrowed marketing concepts from other industries. Several utility marketing specialists have remarked that the "M" in "DSM" really stands for "marketing," not "management." This demand-side marketing concept focuses on understanding, educating, and satisfying the customer.

With the completion of several large generating units, the decline in world energy prices, and the Texas recession, several electric utilities in Texas experienced excess capacity reserves during the mid-1980s. In 1986, HL&P reversed its prior conservation emphasis to study its marketing options. The fall in natural gas prices made electric utilities sensitive to end-use competition, both from industrial self-generation and in the residential heating and water heating markets. As a result, the late 1980s saw electric utilities focus on retaining and increasing sales.

While the activity in the industrial markets remains focused on load retention, utilities have recently begun to reemphasize conservation in the residential and commercial classes. While some of this reemphasis may be attributed to a regulatory push, it is apparent that electric utilities are trying to maintain or improve their market share by providing improved services to customers. It is too soon to state with certainty, however, whether electric utilities will fully embrace conservation-oriented programs until rapid growth is resumed.

Market Barriers to Energy Efficiency

Barriers to the efficient use of electric energy have been widely identified and reported in studies of energy efficiency. While the market for conservation products has numerous buyers and sellers, relatively unrestricted entry and exit, and unrestricted prices (key elements of a perfectly competitive market), it often does not provide sufficient or consistent incentives to customers and utilities to increase the energy efficiency of end-use devices. The current market is imperfect to the extent that:

1. Technology is rapidly changing
2. Information is expensive for individuals to acquire
3. Patterns of building ownership and occupancy inhibit efficient investments
4. Consumers require quick paybacks
5. Traditional rate making does not generally reflect long-run marginal costs

The conservation product line has expanded, diversified, and become more economic during the past decade. European and Japanese manufacturers have responded to energy price changes by adapting their products to meet the American market's requirements. Light bulbs and ballasts, window films, high-efficiency appliances, and microprocessor control devices which were generally unavailable a few years ago have appeared commercially. The availability of these technologies has created both opportunities and uncertainty.

Technical information about the efficient use of energy is not readily available to all consumers. The costs to an individual consumer for technical information may exceed the benefits. In all sectors, the price of electricity is just part of total expenses and may not capture the full attention of the customer. Providing information to customers is a focus of nearly all demand-side programs.

Building ownership and occupancy patterns may affect the cost of efficiency as well. Renters pay electric bills (Why make an improvement if you cannot take it with you?), while landlords fix the roof (Why upgrade the air conditioner if you do not pay the bills?). It is common for building occupancy to change frequently, thus reducing the incentives for long-term investments. The numerous parties in the housing or commercial space market -- developers, contractors, real estate agents, lenders, property managers, home owners, and lessees -- must focus on many other issues aside from energy. The result is commonly an under-investment in the energy efficiency features of a building.

Demand-side planners frequently refer to "lost opportunities" for conservation as those actions which must be taken at a given time and place or be "lost" for a considerable period of time. The structural efficiency of a new building is determined during the conceptual design, blueprint, and construction phases. The orientation of a building influences its energy efficiency because it determines exposure to the environment. The size and location of windows changes the amount of solar gain, as does the design of the windows, types of window films and window coverings, shading, and operability of the window opening. Similarly, the design of the building shell determines its thermal efficiency and thus the amount of heat loss in the winter and heat gain in the summer. The same is true of building equipment including air conditioning, heating, ventilation and lighting in most buildings, and domestic hot water, refrigeration, and cooking equipment in others.

In most cases, early design decisions affect energy use for decades -- until buildings are replaced or undergo major remodeling. Electric utilities can effect a significant improvement in the efficiency of buildings in their service area, reducing revenue requirements, deferring new generating capacity, and reducing customer costs through voluntary programs.

Expectations about future costs of energy differ among groups as do their discount rates. Many consumers require a quick payback when comparing energy efficiency investment costs and future energy savings. Customers exhibit discount rates in their buying habits which are high -- as high as 100 percent (requiring a one-year payback) for the energy savings return of certain appliances. In some cases, information and modest utility support of an efficient measure may be enough to cause the desired action.

In the commercial and industrial sectors, architects and engineers respond to the economics of the corporation, not those of the electric system. High rates of return ("hurdle rates") predominate because energy efficiency investments must compete with alternative uses of capital - often at rates of return of 30 percent or more. Frequently there is a misunderstanding regarding the risk of energy efficiency investments because the technologies are outside corporate areas of specialization. Again, information is crucial to demand-side management.

Where uncertainty about the return on investment persists, monetary assistance may overcome customers' reluctance to invest in energy efficiency. Incentives take many forms -- loans, coupons, rebates -- depending on what will cause the desired behavioral change at the most reasonable cost. The provision of incentives has been particularly evident in the commercial cool storage programs (cooling load shifting to nighttime). Here, TU Electric has found that significant utility incentives, in combination with time-of-use rates, allow the customer to overcome the uncertainty associated with a new technology.

Finally, the price of electricity is not a perfect measure of the cost of incremental generating capacity. Traditional rate-making usually establishes rates based on average embedded costs of production. Historic costs may not reveal the utility's long-term cost (the cost of a new increment of capacity), or the cost of providing energy at different times of the day or year. Architects, builders, and their professional organizations employ rules of thumb and cost guidelines based on these average cost pricing rules. Building code guidelines are based on average, not marginal, costs of electricity; hence, they may not provide a good signal for end-use efficiency.

Federal Initiatives The federal government has taken a moderately active role in mandating efficiency during the past fifteen years. The 1975 Energy Policy and Conservation Act established the federal appliance labeling program. An analysis of building and appliance efficiency standards arose from the 1976 Energy

Conservation and Production Act. Building efficiency standards took the form of voluntary Building Energy Performance Standards. The 1978 National Energy Conservation Policy Act created the Residential Conservation Service (RCS) programs. RCS was a mandatory home audit program implemented by the state's major utilities until the federal mandate ended in June 1989.

In its most recent major energy conservation legislation, the Congress and a coalition of private-sector organizations initiated the National Appliance Energy Conservation Act of 1987 (NAECA). This law establishes technical efficiency standards for major residential equipment. The standards are being phased-in from 1988 to 1992. For example, new central air conditioners have a weighted average seasonal energy efficiency rating (SEER) of about 9.5 now (1990); by 1992 the minimum rating will be 10.0 SEER. Figure 5.2 provides a dramatic view of the efficiency trends in residential-sized air conditioners and heat pumps. Current trends without the NAECA imply that cooling equipment SEERs would average 10.0 to 11.0 in Texas during the 1990s.

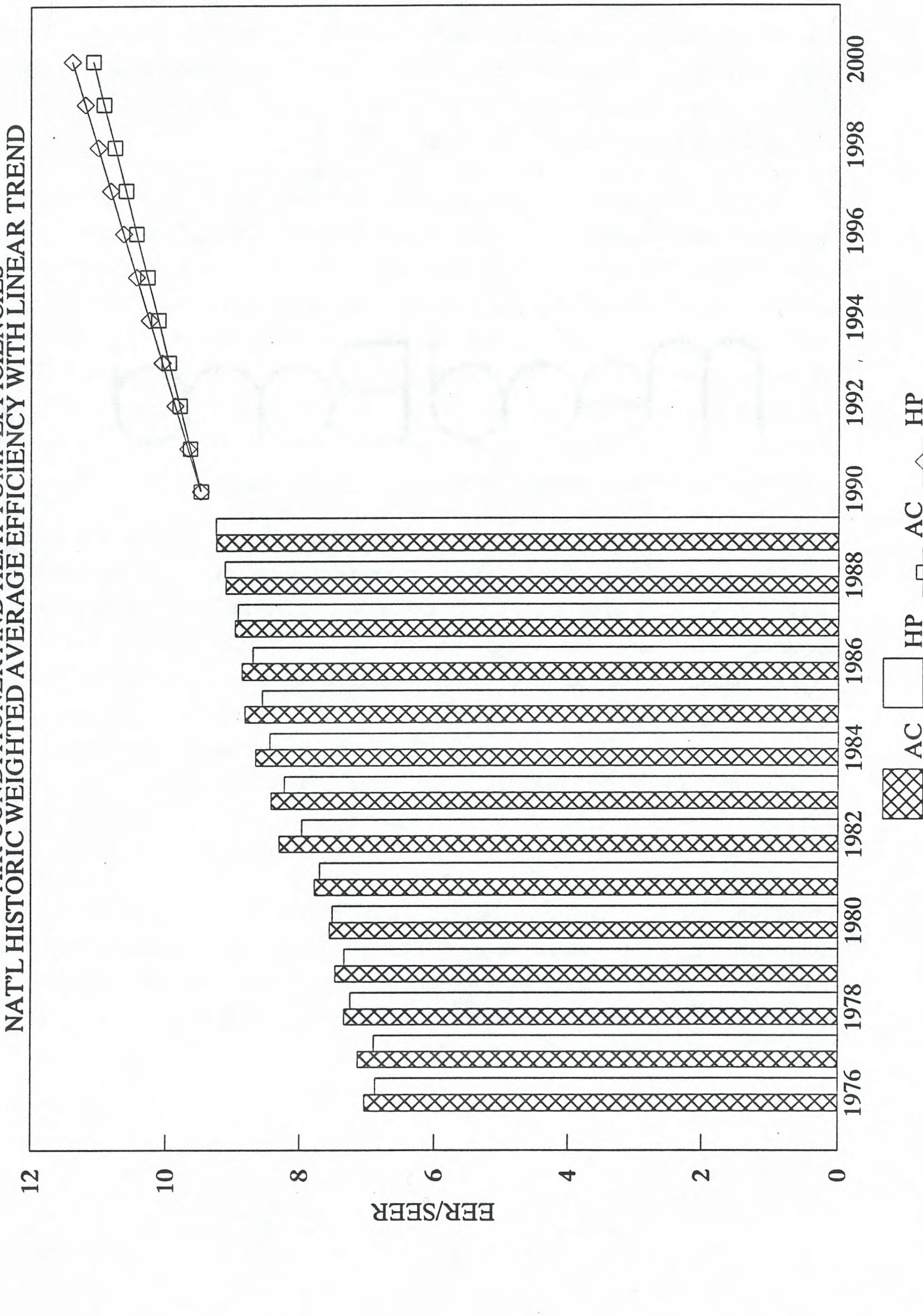
Current proposed federal legislation is focused on energy efficiency for the sake of industrial competitiveness, energy security, and environmental concerns. By nearly any measure, U.S. industries use more energy than their counterparts in competing industrial countries. While energy prices remained low, this was of little concern. But energy price escalation has reduced the ability of certain industries to compete in international markets. Policies which reduce energy imports are considered a matter of national security by certain members of congress. The environmental issues of acid rain, global warming, and ozone depletion are beginning to have repercussions in the electric industry.

Energy Efficiency Plan Filing Requirements

Amendments in 1983 to the PURA make explicit the consideration of the conservation of resources in the resource planning process. Under its Substantive Rule 23.22, the Energy Efficiency Plan Rule, the Commission regulates the renewable resource, supply efficiency, conservation, and load management activities of electric utilities.

FIGURE 5.2

AIR CONDITIONER AND HEAT PUMP EFFICIENCIES
NAT'L HISTORIC WEIGHTED AVERAGE EFFICIENCY WITH LINEAR TREND



Source: various ARI publications and personal communications.

Twenty-five utilities in Texas must file Energy Efficiency Plans every two years.[4] Fourteen rural electric cooperatives, one river authority, and ten investor-owned utilities have been considered eligible under this rule. The DSM activities of non-generating electric cooperatives are not discussed in this report as the impact of their activities is reflected in the forecasts and resource plans of generating utilities.

Energy Efficiency Plans contain a statement of energy efficiency goals, a description of the program selection process, program descriptions, participation and cost-benefit data, and a description of the accounting system used to track costs. These data include fifteen-year program participation projections, recurring and nonrecurring program costs, and kilowatt demand reductions and kilowatt-hour energy savings per participating customer. The Commission evaluates these plans in major rate cases, new generating capacity certification proceedings, and in the preparation of this biennial forecast.

Energy Efficiency Goals

Corporate energy efficiency goals are a prerequisite to the selection and implementation of demand-side management programs. The hot Texas summers drive the annual peak of most of the state's utilities. As a result, several utilities establish peak-demand reduction as a goal.

Where adequate capacity reserves exist, as is the case of much of the state, utilities embrace load-factor improvement goals. Annual system load-factor may increase due to both peak-demand reduction programs and off-peak sales. As a result, many of the state's utilities have opted for what they consider a balance between peak reduction activities and off-peak sales.

In general, utilities with increasing sales (like TU Electric) have an energy efficiency goal of peak-demand reduction, while utilities with excess generating reserves state their goals in terms of load-factor improvement. Load-factor improvement goals and the resultant off-peak sales promotion programs will continue to receive Commission staff scrutiny in Texas. The energy efficiency goals of the major generating utilities follow.

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4 Municipalities in Texas have original jurisdiction in the regulation of public utilities. Municipally-owned electric utilities and those with fewer than 20,000 customers do not file Energy Efficiency Plans pursuant to Substantive Rule 23.22.

TU Electric's Energy Efficiency Goals

In 1980, TU Electric established a peak-demand reduction goal of 1,000 MW by 1985. Through the end of 1989, TU Electric claims a savings of 1,196 MW (975 MW from passive DSM and an additional 221 MW from interruptible load). TU Electric's current energy efficiency goal is to: 1) serve 20 percent of the expected growth in peak-demand through DSM, and 2) increase off-peak load through load shifting and the addition of new off-peak load.

HL&P's Energy Efficiency Goals

In the early 1980s, HL&P implemented conservation programs which resulted in a peak-demand reduction of approximately 200 MW. HL&P states that its current energy efficiency goal is to implement programs which 1) reduce rates, 2) benefit participants, 3) allow customers to manage energy costs, and 4) promote energy efficiency. HL&P's stated goals are to increase revenues and achieve 149 MW of peak-demand reduction from conservation programs by 1995. HL&P also has about 1,000 MW of interruptible load on its system and has encouraged economic development in its service area to increase sales.

GSU's Energy Efficiency Goals

GSU states that its goal has been to provide customers with information about the wise use of electricity. GSU's current energy efficiency goal is to continue off-peak sales promotion and conservation activities which affect the long-lasting efficiency decisions of its customers. GSU does not quantify its demand-side energy efficiency goals.

CPL's Energy Efficiency Goals

CPL's past energy efficiency goals were stated as program-by-program objectives. CPL's current goal is to reduce coincident system peak-demand and shape the naturally-occurring system growth. CPL states its energy efficiency goal in terms of peak-reduction and load-factor improvement: peak-demand will be reduced by 123 MW by 2000; and system load-factor will be improved by 2 percent during the same period.

CPS's Energy Efficiency Goals

CPS has not provided the Commission with a statement of its demand-side energy efficiency goals.

SPS's Energy Efficiency Goals

SPS has maintained an energy efficiency goal of load-factor improvement throughout its history of implementing DSM. SPS seeks to achieve this goal through additions in off-peak sales, strategic load growth, and some peak-demand reduction. Both demand-side programs and rate design focus on this goal. The Company does not quantify its load-factor improvement goal at the system level.

SWEPCO's Energy Efficiency Goals SWEPCO states its past energy efficiency goals in general terms such as "wise energy use" for customers. SWEPCO's current goals are program-based and cover merely two years. SWEPCO does not state or quantify corporate demand-side energy efficiency goals.

LCRA's Energy Efficiency Goals The LCRA's energy efficiency goal is to reduce summer peak-demand by 200 MW by an unspecified date.

COA's Energy Efficiency Goals The COA adopted an energy efficiency goal in 1983 to eliminate the need for one large unit of generating capacity (553 MW) through conservation and load management programs.

WTU's Energy Efficiency Goals WTU's energy efficiency goal has been to reduce peak-demand and energy consumption through supply-side and demand-side efficiency programs. WTU plans to reduce system operating costs and reduce purchases of power through DSM. WTU's current goal is to reduce peak-demand by 0.6 MW and energy usage by 82,600 MWH by 1994.

EPE's Energy Efficiency Goals EPE's past energy efficiency goals have been framed in terms of program-specific objectives. EPE has focused on appliance rebate programs (sales promotion) and the distribution of conservation information. EPE's current energy efficiency goal is to reduce peak-demand to offset the need for peaking units.

TNP's Energy Efficiency Goals TNP's energy efficiency goal is load-factor improvement. TNP plans to achieve load-factor improvement in the future through a combination of peak-demand reduction and off-peak sales promotion programs. TNP states that it will reduce peak-demand by 20.5 MW by 1999.

BEPC's Energy Efficiency Goals BEPC does not state its demand-side energy efficiency goals.

Characteristics of Demand-Side Management Which Enhance or Limit its Use as a Resource

Demand-side resources have unique characteristics which both enhance and constrain their use within an electric resource plan. A good resource plan is flexible enough to deal with the inherent uncertainties of the peak-demand forecast. DSM programs represent a wise addition to a resource plan because:

1. Implementation lead times are short
2. Scale is modest and may be selected by the utility
3. Costs are controllable
4. Growth in sales and peak demand can be deliberately moderated to reduce uncertainty
5. Large-scale failure is unlikely
6. Impact estimation is no more unreliable than peak-demand forecasting

Demand-side programs typically provide planning flexibility because they have short implementation lead times. Utilities with experienced staff and market information can initiate a new program within a matter of months. A less-experienced utility with little data can mimic the experiences of neighboring utilities to implement pilot programs within a year. Naturally the impacts of such a program are small in the first few years as experience is gained and as the customers' needs and preferences are gauged.

Each DSM program is of modest scale. A pilot program will cost thousands, not millions, of dollars. It will have a small impact and thus will cause few problems even if its objectives are not met. Program scale may be increased by nearly any desirable increment. Changes in the scale of a program may be effected within months of a decision to reduce or accelerate participation. Changing the scale of a program is valuable as it allows a utility to adjust activity based on changes in resource needs.

Cost estimates of demand-side programs are not subject to mid-construction adjustments. If program costs increase, the program can be cancelled. Stopping a program does not mean losing the peak-demand reductions to date. The savings to date of passive DSM are unaffected by future program decisions.

The scale of certain demand-side programs have an automatic adjustment mechanism which moderates the impact of economic fluctuations on load growth. Programs targeted at new building efficiency will meet, exceed, or fall short of specified goals as the business cycle fluctuates. If growth is small, construction starts will be few and DSM will barely affect demand. In contrast, more rapid economic growth may result in a greater savings if the utility adds several staff people and encourage more participation. In this manner, an effective set of DSM programs can reduce the unknown effects of the future.

From the perspective of electric utility system planners and operators, demand-side programs are sometimes viewed as unreliable. Part of this view stems from a lack of understanding of DSM, which in turn is related to the novelty of this field. Commercial cool storage is a relatively new phenomenon in its present form, but supply-side planners and operators can appreciate its impact once a building's load curves are examined.

Electric utilities and reliability councils distinguish, as we have here, between the reliability of passive and active demand-side programs. There is uncertainty associated with active DSM because, although a customer may have a contractual agreement to cooperate, the utility is not sure whether a contract will be broken at a critical moment or whether a contract will be renewed. Fortunately, most utilities and interruptible customers have good working relationships and historical data have shown this not to be a problem.

Passive DSM is sometimes perceived as uncertain because planners do not consider the forecasts of program impacts reliable. This perception arises in part because efficiency gains cannot be measured in the manner that capacity additions are measured. One can see and touch a generating station but one never sees a saved kilowatt-hour. One also hears that "the customer controls the thermostat" as a reason why utilities should not rely on these programs. In fact, the impact of thousands of efficient homes (DSM program participants) are routinely measured and analyzed using statistical tools -- tools similar to those used in the preparation of an econometric forecast.

All resource decisions -- whether demand-side or supply-side -- are based on estimates of the future. Decisions to build a new generating facility rely on one's knowledge of future construction costs. In the case of DSM, program planners begin with preliminary engineering estimates of program impacts. Pilot programs allow a utility to further analyze the program impact and prepare new estimates. Whatever the method, most utilities in Texas have started this process to improve demand-side program data and thus allow a comparison of demand-side and supply-side resources.

Historic Program Expenditures

The Energy Efficiency Plan filing format requires reporting of historic program costs. Table 5.5 is a summary of the total cost of DSM programs in Texas during the 1980s as reported by TU Electric, HL&P, CPL, CPS, SPS, SWEPCO, LCRA, COA, WTU, and TNP. Similar data were not available at the time of publishing for GSU, EPE, and BEPC.

DSM expenditures are provided in two categories: incentive payments and other expenses. All other customer service expenditures (non-DSM) are provided as a basis of comparison.

Most of the state's major utilities conduct cost-benefit analysis to examine the cost-effectiveness of DSM programs. The costs and benefits are reviewed from the perspective of the participating customer, the impact on rate levels, the impact on revenue requirements, and the total costs of DSM resources to the utility and its participating customers. The results are reported in Energy Efficiency Plans.

TABLE 5.5

DEMAND SIDE PROGRAM EXPENDITURES
1980 - 1990

Year	(a) DSM Incentive Payments	(b) Other DSM Expenditures	(c) Total DSM (a+b)	(d) All Other Customer Services	Total (c+d)
1980	$179,601	$4,690,247	$4,869,848	$12,273,678	$17,143,526
1981	$2,263,778	$5,936,781	$8,200,559	$14,725,242	$22,925,801
1982	$15,541,325	$9,471,942	$25,013,267	$16,323,114	$41,336,381
1983	$27,385,918	$10,116,428	$37,502,346	$20,224,918	$57,727,264
1984	$44,427,804	$10,067,346	$54,495,150	$20,413,918	$74,909,068
1985	$31,087,231	$14,733,084	$45,820,315	$20,040,428	$65,860,743
1986	$25,858,384	$13,614,924	$39,473,308	$19,574,157	$59,047,465
1987	$18,583,369	$16,158,294	$34,741,663	$20,555,013	$55,296,676
1988	$12,812,785	$22,310,317	$35,123,102	$20,403,406	$55,526,508
1989	$14,447,583	$23,271,877	$37,719,460	$23,411,891	$61,131,351
1990	$13,551,489	$16,844,929	$30,396,418	$25,807,496	$56,203,914

Note: Total DSM and other customer service expenditures reported by TU Electric, HL&P, CPL, CPS, SPS, SWEPCO, LCRA, COA, WTU, and TNP. Similar data were not available for GSU, EPE, and BEPC. Several of the listed utilities did not maintain 1980-1983 information in these categories. In addition, 1990 does not include LCRA and COA projections.

Recommended Exogenous Factor Adjustments

Exogenous factor adjustments include the effects of laws and customer actions beyond the control of the utility. Activities which cannot be controlled by the utilities include the impact of the federal appliance efficiency standards, the impact of self-generation, significant unanticipated load growth, and the actions of standby customers.

Laws passed in the late 1980s have influenced consumption and encouraged cogeneration. Some customer actions have occurred for several years and are assumed to be embedded in the data used to prepare the staff's "raw" econometric forecast. The following sections describe the exogenous factor adjustments made to the current forecast. The adjustments for each service area are presented in Tables 5.6 and 5.7.

The Impact of the National Appliance Energy Conservation Act of 1987

Utilities were required in the December 1989 filing to estimate the impact of the NAECA. The Commission's End-Use Modeling Project staff reviewed this information and concluded that the reported impacts overstate the likely effect of the law.[5] The sum of the reported impacts for six utilities was 3,028,607 MWH in 1999.[6]

The Residential End-use Energy Planning System (REEPS) model explicitly considers end-use fuel, appliance type, and efficiency choice in new and replacement purchase decisions. REEPS is well suited to consider the impact of appliance efficiency standards. The End-use Modeling Project staff estimated that 973,000 MWH will be conserved statewide by 1998 as a result of the NAECA. This corresponds to a peak-demand reduction of about 600 MW. The difference between the Commission staff estimate and the utilities' estimate is largely related to three areas of disagreement: 1) input assumptions in REEPS modeling procedures, 2) understatement of the energy efficiency trends of residential appliances, and 3) disagreement regarding whether NAECA minimum efficiencies will be periodically updated by the federal government.

Staff allocated this statewide REEPS estimate to the thirteen major service areas using the ratio of service area residential appliance electricity consumption to statewide

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5 Partial funding for the Commission's End-Use Modeling Project was secured through the Governor's Energy Office and the State Energy Conservation Program.

6 Public Utility Commission of Texas, "Final Report for Phase 3 of the PUCT End-Use Modeling Project," June 1990, Chapter 2, Table 2.9, page 2.22.

appliance consumption. Coincident peak load-factors were then applied to calculate the coincident peak-demand impact in megawatts from the sales impact. Tables 5.6 and 5.7 provide the detail for each service area.

The Impact of Self-Generation and Exceptional Growth

Self-generation increased in Texas during the 1980s. Customer growth and new industrial plant opening were a mainstay of the Texas economy in the 1970s and early 1980s. Therefore, the effects of self-generation and industrial growth are likely reflected in the historic data (for example, in nonagricultural employment variables) used to prepare the "raw" sales forecasts. Commission staff believes that its econometric models are sufficiently robust to account for both future self-generation and exceptional industrial load growth.

The Impact of Standby Customers

Firm standby customer contracts total 905 MW in the Texas portion of four generating utilities: HL&P, GSU, CPL, and TNP. Generally, these are contracts with customers who self-generate and who wish to receive power whenever they experience an outage on their generators. Power demanded by standby customers must be available on the system; thus it is reasonable that utilities add a portion of standby contracts to their capacity planning requirements.

Commission staff has examined the amount and distribution of standby customers in Texas and concluded that the following megawatts must be added to the peak-demand forecasts of three utilities:

Utility	MW
HL&P	56
GSU (Texas)	21
GSU (total system)	42
CPL	37

The planning criterion was the average contract plus the expected value of outages at all units.

TABLE 5.6
MWH IMPACTS OF THE NAECA AT THE CUSTOMER METER 1990 - 2000

Year	TU	HLP	GSU-Texas	GSU-Total	CPL	CPS
1990	129,192	55,811	11,208	22,527	23,302	21,242
1991	162,943	71,142	14,339	28,821	29,784	27,025
1992	196,694	86,473	17,470	35,114	36,266	32,809
1993	243,893	106,945	21,587	43,389	44,823	40,595
1994	291,091	127,417	25,704	51,664	53,379	48,381
1995	325,974	142,486	28,730	57,746	59,671	54,116
1996	360,857	157,555	31,756	63,828	65,962	59,852
1997	388,726	169,343	34,106	68,551	70,856	64,356
1998	416,595	181,130	36,455	73,273	75,751	68,860
1999	416,595	181,130	36,455	73,273	75,751	68,860
2000	416,595	181,130	36,455	73,273	75,751	68,860

Year	SPS-Texas	SPS-Total	SWEPCO-Texas	SWEPCO-Total	LCRA	COA
1990	5,145	7,120	5,184	12,776	14,470	0
1991	6,998	9,684	6,671	16,441	18,778	0
1992	8,850	12,249	8,158	20,107	23,087	0
1993	10,786	14,927	10,066	24,811	28,431	0
1994	12,722	17,606	11,975	29,514	33,775	0
1995	14,110	19,528	13,374	32,964	37,682	0
1996	15,499	21,450	14,774	36,413	41,588	0
1997	16,439	22,750	15,847	39,059	44,533	0
1998	17,378	24,050	16,921	41,705	47,477	0
1999	17,378	24,050	16,921	41,705	47,477	0
2000	17,378	24,050	16,921	41,705	47,477	0

Year	WTU	EPE-Texas	EPE-Total	TNP	BEPC	Texas Total
1990	6,621	2,714	3,511	7,840	6,812	289,538
1991	8,444	3,868	5,004	9,927	8,833	368,752
1992	10,267	5,021	6,496	12,015	10,855	447,965
1993	12,696	6,062	7,842	14,883	13,370	554,137
1994	15,125	7,103	9,188	17,752	15,885	660,309
1995	16,913	7,835	10,136	19,869	17,724	738,484
1996	18,700	8,568	11,083	21,985	19,563	816,660
1997	20,097	9,004	11,648	23,663	20,951	877,921
1998	21,494	9,441	12,213	25,341	22,339	939,182
1999	21,494	9,441	12,213	25,341	22,339	939,182
2000	21,494	9,441	12,213	25,341	22,339	939,182

Note: Assumes zero MWH impact in the COA service area; thus the total does not equal 973,000 MWH in 1998 as originally forecast by the End-use Modeling Project staff using the REEPS model.

TABLE 5.7
PEAK DEMAND IMPACTS OF THE NAECA AT THE POINT OF GENERATION 1990 - 2000

Year	TU	HLP	GSU-Texas	GSU-Total	CPL	CPS
1990	106	32	7	13	14	12
1991	127	39	8	16	17	15
1992	149	46	9	19	20	17
1993	187	57	12	23	25	22
1994	225	69	14	28	30	26
1995	254	77	16	32	34	29
1996	282	86	18	35	38	33
1997	307	93	19	38	41	35
1998	332	101	21	41	44	38
1999	332	101	21	41	44	38
2000	332	101	21	41	44	38

Year	SPS-Texas	SPS-Total	SWP-Texas	SWP-Total	LCRA	COA
1990	4	5	4	10	11	0
1991	5	6	5	12	14	0
1992	5	7	6	14	16	0
1993	7	9	7	18	20	0
1994	8	11	9	21	24	0
1995	9	13	10	24	27	0
1996	10	14	11	26	31	0
1997	11	15	12	29	33	0
1998	12	16	13	31	36	0
1999	12	16	13	31	36	0
2000	12	16	13	31	36	0

Year	WTU	EPE-Texas	EPE-Total	TNP	BEPC	Texas Total
1990	5	2	2	6	5	208
1991	6	2	3	7	6	251
1992	7	3	4	9	8	295
1993	9	3	4	11	10	370
1994	11	4	5	13	11	444
1995	12	5	6	15	13	501
1996	14	5	7	16	14	558
1997	15	5	7	18	16	605
1998	16	6	8	19	17	655
1999	16	6	8	19	17	655
2000	16	6	8	19	17	655

Note: Assumes zero peak demand impact in the COA service area.

Recommended Demand-Side Management Adjustments

The recommended DSM adjustments are comprised of active and passive DSM impacts. This distinction is hardly arbitrary. Active DSM is dispatchable; a utility initiates the signal to reduce load during a critical period. The signals vary by type of active DSM. In the three most relevant cases, instantaneous interruptible goes off-line when the frequency falls, direct load control of appliances results from a signal to a cycling switch on the appliance, and telephone communications are used to tell customers to shut off their loads (non-instantaneous interruptible). A percentage of available loads are considered interruptible for planning purposes.

Passive DSM, in contrast, results from utility programs to encourage equipment efficiency or to shift loads. The appropriate adjustment to the forecast varies by type of program. Each DSM program is listed in Table 5.8. This list also indicates:

1. Eligible customer class
2. The application (technology, device, or end-use)
3. The expected megawatt impact in the summer of 1992
4. The MWH impact in 1992
5. When the program started
6. The current status of the program

The cumulative three-year impacts are provided to give a sense of the relative scale of programs. Figure 5.3 displays the relative magnitude of active and passive DSM achievements in the three years ending in 1992. Figure 5.4 shows the energy savings for passive DSM programs and the sales impacts of those passive DSM activities (such as off-peak lighting programs) which increase electricity usage.

Program descriptions and more detailed data on past achievements, historic costs, projected participants, and estimated impact per participant are provided in each utilities' Energy Efficiency Plan (on file in the Commission's Central Record Division).

Tables 5.10 to 5.43 summarize the active and passive DSM adjustments for each utility service area. As was the case in prior tables, the peak-demand adjustments are presented by category: exogenous factors, active DSM, and passive DSM. The energy adjustments are presented by customer class.

TABLE 5.8

Demand-Side Management Programs in Texas

Program Listing and 1990-1992 Impacts

Texas Utilities Electric Company

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Energy Action New Single-Family	Residential	Building envelope, heat pump, air conditioner, water heater (multi-fuel new homes)	28.5	43,782	Jan 81	Full scale
Energy Action New Multi-Family	Residential	Building envelope, heat pump, air conditioner (multi-fuel new)	0.1	348	Jan 81	Full scale
Energy Action New Non-Residential	Commercial	Building envelope, heat pump, air conditioner (multi-fuel new)	10.8	22,765	Jan 87	Full scale
Energy Action Existing Single-Family	Residential	Heat pump, air conditioner	33.6	41,907	Jan 81	Full scale
Energy Action Existing Multi-Family	Residential	Heat pump, air conditioner	1.2	1,771	Jan 81	Full scale
Energy Action Existing Non-Residential	Commercial	Heat pump, air conditioner	9.6	15,511	Jan 82	Full scale
Energy Action Room Unit	Residential, Commercial	Heat pump, air conditioner	0.2	245	Jan 81	Full scale
Energy Action Elec. Water Heater Assist	Residential	Water heater	0.2	719	Jan 81	Full scale
Energy Action Geothermal Heat Pump	Residential	Geothermal (ground source) heat pump	0.3	734	Jan 88	Full scale
Energy Action Thermal Storage	Commercial, Industrial	Cool storage	18.7	0	Jan 82	Full scale

Reductions in peak demand and energy usage are displayed as positive numbers. NA: not available.

TU Electric (Cont'd) Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Energy Action Lighting	Commercial, Industrial	Efficient lighting equipment	48.4	161,562	Jan 82	Full scale
Energy Action Interruptible Load	Commercial, Industrial	Interruptible service	342.1	0	Jan 83	Full scale
Energy Action Operation Load Shift	Commercial, Industrial	Load shift	64.5	0	Jan 84	Full scale
Direct Load Control	Residential	Appliance cycling	9	0	Jan 86	Pilot
Off-peak Lighting	Residential, Commercial, Industrial	Outdoor lighting	0	-26,466	NA	NA
Future Technologies	All	Unspecified	43	73,561	NA	NA

Houston Lighting & Power Company

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Good Cents New Home	Residential	Building envelope, heat pump, air conditioner, water heater (multi-fuel new homes)	6.7	3,650	May 88	Full scale
Heat Pump Program	Residential, Commercial	Heat pump	0.2	95	May 88	To end Dec 90
Contract Lighting Service	Residential, Commercial, Industrial	Security/area efficient lighting	0	-19,724	Jun 87	Full scale
Nite Light	Residential	Security lighting	0	-1,091	Sep 88	Full scale
Energy Check-up	Residential	Energy audit	0	0	Jan 82	Full scale
Weatherization Assistance	Residential	Building envelope	0	1,074	Mar 83	Full scale
Good Cents Apartment	Residential	Building envelope, heat pump, air conditioner (multi-fuel new)	0.7	1,100	Oct 90	Pilot
Commercial Audit	Commercial	Energy audit	10.0	28,777	Jan 82	Full scale
Economic Development	Industrial	Various industrial applications	0	0	Jan 88	End Dec 90

Reductions in peak demand and energy usage are displayed as positive numbers. NA: not available.

HL&P(Cont'd) Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Commercial Cool Storage	Commercial, Industrial	Cool storage	9.7	-1,106	Jan 89	Full scale
Energy Efficient HVAC	Residential	Heat pump, air conditioner	9.6	16,334	Jan 91	Planning phase
Direct Control	Residential	Heat pump, air conditioner	3.4	0	Jan 89	Pilot
Soft Control	Residential	Appliance control	0.2	0	Jan 90	Pilot
Good Cents Retrofit	Residential	Building envelope, heat pump, air conditioner	0	0	Jan 91	Design phase
Commercial Structural Efficiency	Commercial	Building envelope, lighting	2.9	8,222	Jan 91	Design phase
Commercial Lighting Efficiency	Commercial	Lighting	0	0	Jan 91	Design phase
Interruptible Rates	Commercial, Industrial	Interruptible service	635	0	Jan 67	Full scale

Gulf States Utilities Company

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Good Cents Home	Residential	Building envelope, heat pump, air conditioner, electric furnace (all-electric new homes)	0	0	Jan 86	Full scale
Centsable Heat Pumps	Residential	Heat Pump	0	0	Jan 85	Full scale
Centsable Water Heating	Residential	Water heater	0	0	Jul 87	Full scale
Centsable Lighting	Residential, Commercial, Industrial	Outdoor lighting	0	0	NA	NA
Commercial Heat Pumps	Commercial	Heat pump	0	0	Jan 86	Full scale
Industrial Rates	Industrial	Interruptible service	63	0	1979	Full scale

Reductions in peak demand and energy usage are displayed as positive numbers. NA: not available.

Central Power and Light Company

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Good Cents Home	Residential	Building envelope, heat pump (all-electric new homes)	2.8	0	Jun 83	Full scale
Centsable Home	Residential	Building envelope	2.1	0	Jan 87	Full scale
Heat Pump Incentive	Residential	Heat pump	3.3	0	Sep 86	Full scale
Commercial Heating	Commercial	Heat pump	0	-1,764	Jan 90	To end Dec 92
Commercial Cooking	Commercial	Range	-0.9	-1,889	Jan 90	Design phase
Better Thermal Utilization	Commercial Industrial	Audit	0	0	Jan 90	Full scale
Irrigation Pump Testing	Agricultural	Technical assistance -- pump efficiency	0	0	1987	Full scale
Interruptible Load	Industrial	Interruption	268	0	NA	Full scale

City Public Service Board of San Antonio

No programs were reported.

Southwestern Public Service Company

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Energy Efficient Home	Residential	Building envelope, heat pump, electric furnace (all-electric new homes)	0.5	-5,123	Jan 76	Full scale
Dual-Fuel Heat Pump	Residential	Heat pump	0	-8,094	Jan 82	Full scale
Residential Energy Audit	Residential	Building envelope, misc. measures	0	0	Jul 89	Full scale

Reductions in peak demand and energy usage are displayed as positive numbers. NA: not available.

SPS (Cont'd)

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Add-on Heat Pump (electric resistance replacement)	Residential	Heat pump	0	0	Aug 82	Full scale
Residential Security Lighting	Residential	Outdoor lighting	0	0	Jan 90	Full scale
Energy Efficiency Design Assistance	Commercial	Building envelope, HVAC	0	0	Mar 90	Pilot
Leased Lighting	Commercial, Industrial	Outdoor lighting	0	0	Jan 90	Pilot
Interruptible Water Pumping	Municipal	Interruption	17	0	NA	NA
Interruptible Irrigation Loads	Wholesale (Retail Agricultural)	Interruption	16	0	NA	NA

Southwestern Electric Power Company

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Improved Energy Efficient Home	Residential	Building envelope (all-electric new homes)	0	0	Jan 76	Full scale
Air Conditioner Maintenance	Residential	Air conditioner	0	0	Mar 83	Full scale
Existing Home Heat Pump Replacement	Residential	Heat pump	0	0	Jan 89	Full scale
Interruptible Power	Industrial	Interruptible service	45	0	Oct 76	Full scale

Lower Colorado River Authority

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Air Conditioner and Water Heater Cycling	Residential, Commercial	Heat pump, air conditioner, & water heater cycling	30.8	0	Jul 86	Full scale
Cooling Efficiency	Residential, Commercial	Heat pump, air conditioner	10.2	8,685	Sep 83	Full scale

Reductions in peak demand and energy usage are displayed as positive numbers. NA: not available.

LCRA (Cont'd)

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Good Cents Home	Residential	Building envelope, heat pump, air conditioner (Multi-fuel new homes)	1.4	0	May 86	Full scale
Commercial Lighting Rebate	Commercial	Lighting	2.0	4,993	Dec 86	Full scale

City of Austin Electric Utility

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Residential Loan	Residential	Building envelope, HVAC	5.3	16,000	1983	Full scale
Whole House	Residential	Building envelope, HVAC	5.1	10,408	Jun 86	Full scale
New Home Efficiency Rating	Residential	Building envelope, HVAC	2.5	9,300	1985	Full scale
Residential Appliance Efficiency	Residential	Air conditioner, heat pump, water heater	15.0	53,200	1982	Full Scale
Multi-Family	Residential	Building envelope, HVAC	1.0	7,300	Jan 90	Pilot
Direct Weatherization	Residential	Building envelope	0	0	1982	Full scale
Commercial Appliance Efficiency	Commercial	Air conditioner, heat pump	2.3	5,600	1982	Full scale
Commercial Energy Management	Commercial	Lighting, building envelope, HVAC	10.0	51,600	Sep 86	Full scale
New Construction Commercial	Commercial	Lighting, building envelope, HVAC	1.9	2,500	Mar 88	Full scale
Thermal Energy Storage	Commercial	Cool storage	3.6	0	1989	Full scale
ElectriCredit	Residential	Appliance cycling	2	0	1985	Full scale
Municipal	Municipal	Building envelope, HVAC, lighting	0.3	1,800	1983	Full scale

Reductions in peak demand and energy usage are displayed as positive numbers. NA: not available.

West Texas Utilities Company

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Energy Savings Plan Residential	Residential	Building envelope, air conditioner, heat pump, solar or heat recovery water heating (multi-fuel new homes)	1.5	0	Jan 83	Full scale
QUEST (audit)	Residential	Building envelope, misc. measures	0	0	Apr 85	Full scale
Energy Savings Plan Commercial	Commercial	Building envelope, HVAC	1.1	0	Jan 87	Full scale
Commercial Audit	Commercial	Building envelope, HVAC	0	0	Jan 83	Full scale
Industrial Energy Audit	Industrial	Various	0	0	Mar 89	Full scale

El Paso Electric Company

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Low Income Weatherization	Residential	Building envelope	0	0	Jan 90	Full scale
Residential Audit	Residential	Energy audit	0	0	Jun 89	Full scale
Residential Lighting	Residential	Lighting	0	0	Jan 90	Design phase
Commercial/Industrial Audit	Commercial, Industrial	Energy audit	0	0	Jul 88	Full scale
Thermal Energy Storage	Commercial, Industrial	Cool storage	0.2	0	Mar 87	Suspended
Floodlight Program	Commercial	Security lighting	0	0	NA	Design phase
Precooler Pad Pilot	Commercial	Precooler pad for cooling	0	0	Jan 90	R&D
School Lighting Controls	School districts	Lighting controls	0	0	Jan 90	Pilot

Reductions in peak demand and energy usage are displayed as positive numbers. NA: not available.

Texas-New Mexico Power Company

Program Name	Customer Class	Application	Peak MW Impact 1992	Energy Impact 1992 MWH	Start Date	Status
Good Cents Home	Residential	Building envelope, heat pump, air conditioner (multi-fuel new homes)	2.3	1,326	Jul 90	Pilot
High Efficiency AC & Heat Pump	Residential	Heat pump, air conditioner	2.2	1,352	Jul 90	Pilot
Interruptible Irrigation	Agricultural	Load shifting	0	0	1983	Full scale

Brazos Electric Power Cooperative

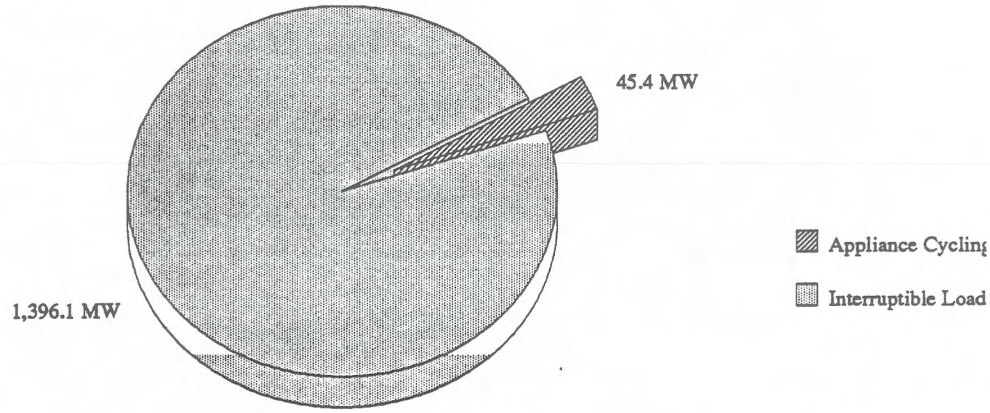
No programs were reported.

Reductions in peak demand and energy usage are displayed as positive numbers. NA: not available.

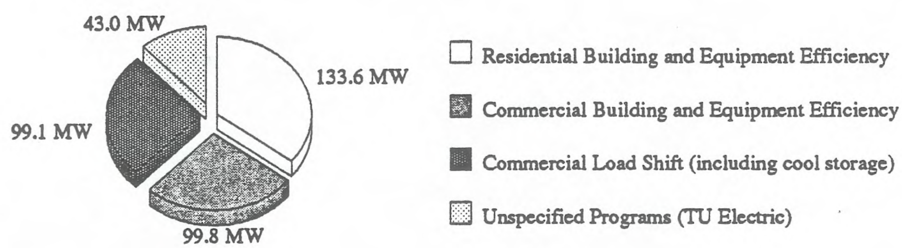
FIGURE 5.3

PROJECTED PEAK DEMAND OF DEMAND-SIDE MANAGEMENT PROGRAMS IN TEXAS
1992*

ACTIVE DSM
1,441.5 MW



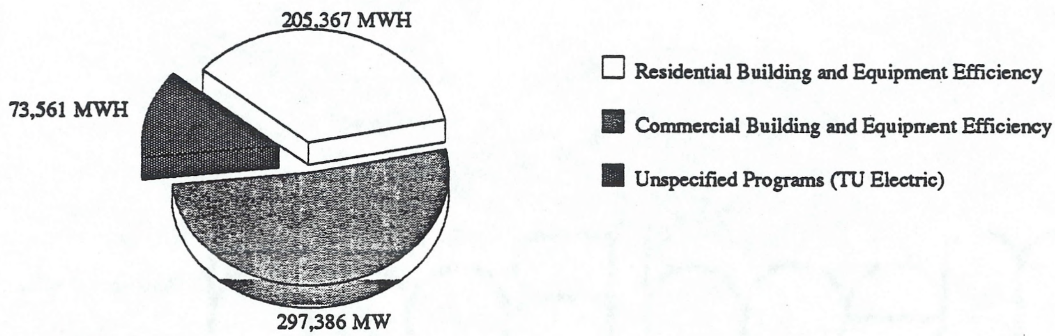
PASSIVE DSM
375.5 MW



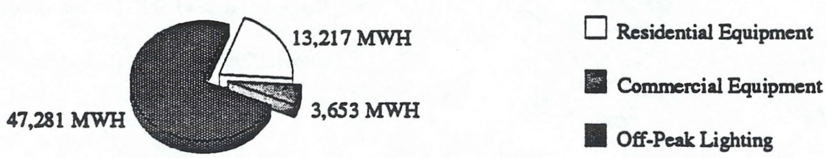
* Active DSM includes past participants who remain interruptible or curtailable. Passive DSM, in contrast, includes only new participants. Past participation in passive DSM programs has resulted in peak-demand reduction which are reflected in the historic data.

FIGURE 5.4
PROJECTED ENERGY IMPACTS OF DEMAND-SIDE
MANAGEMENT PROGRAMS IN TEXAS
1992

SAVINGS
576,314 MWH



SALES INCREASES
64,151 MWH



DSM Adjustments for TU Electric

Active DSM: TU Electric has 221 MW of interruptible load and anticipates nearly 239 additional megawatts over the forecast period. The Company is also experimenting with direct load control of appliances. Staff adopted the estimated impacts of these programs as adjustments to the peak-demand forecast. Neither program affects energy consumption.

Passive DSM: TU Electric offers residential and commercial/industrial structural efficiency and cooling equipment efficiency programs. Commercial lighting efficiency is also promoted. These activities reduce energy usage during the summer months. TU Electric is a leader in the country in promoting commercial thermal (cool) energy storage (about 40 MW now; an additional 8 MW per year forecast). The utility encourages commercial/industrial customers to shift load to off-peak periods and to use a voluntary time-of-day rate. It encourages innovative technologies such as ground-source heat pumps, heat recovery from air conditioners for domestic hot water, and solar water heating. TU Electric also promotes off-peak consumption through its nighttime lighting programs. The PUCT staff has prepared demand-side adjustments based on the most recent information available from the utility.

TU Electric also includes an estimate of the impact of future technologies as an adjustment to its forecast based on its corporate commitment to serve 20 percent of growth through DSM programs. "Future technologies" is not specific and cannot be evaluated for reasonableness. However, its use in resource planning is similar to TU Electric's use of "unspecified resources" in the capacity resource plan. TU Electric has established its capabilities in selecting both generating and DSM resources; thus staff has adopted the Company's future technologies estimate as an adjustment to the staff forecast.

Passive DSM totals 464 MW by 1995 and 948 MW by 2000 in the TU Electric service area.

DSM Adjustments for HL&P

Active DSM: Staff has adopted HL&P's forecast of interruptible loads based on the Company's recent "cogeneration contract renewal scenario" to maintain consistency with staff's resource planning assumptions. The difference with the Company's official 1989 forecast or forthcoming 1990 forecast is not substantive; it is a matter of consistency in presentation. HL&P also makes adjustments for two pilot programs: direct load control and "soft" residential control. Staff has adopted these pilot program projections as adjustments to the staff forecast.

Passive DSM: HL&P has recently modified its Energy Efficiency plan in response to the Commission's Final Order in Docket No. 8425. HL&P's demand-side adjustments for DSM programs have changed as HL&P is eliminating several load growth programs and offering new conservation programs. HL&P has demonstrated in the past that its conservation program implementation can be successful. Whether the current projections materialize in the future will depend on the strength of the Company's commitment to energy efficiency.

Staff has rejected certain of HL&P's reported program impacts (August 1990 Energy Efficiency Plan update) in favor of an independent assessment of current and new programs. Staff believes that the Commercial Cool Storage, Commercial Lighting, Commercial Structural Efficiency, Energy Efficient HVAC (heating, ventilation and air conditioning), and Good Cents Home Programs have a significant potential for peak-demand reductions and energy savings. Staff also adopted HL&P's estimates for the Nitelite, Weatherization, Good Cents Apartment, and Contract Lighting Programs.

Passive DSM totals 168 MW by 1995 and 301 MW by 2000 in the HL&P service area.

DSM Adjustments for GSU

Active DSM: GSU anticipates that about 35 percent of its contract interruptible loads are available for interruption at the time of system peak. Staff has adopted GSU's projections of 83 MW for the total system and 63 MW in Texas. It is likely that these amounts will increase as economic activity increases in the GSU service area.

Passive DSM: GSU's energy efficiency plan contains a mixture of conservation and sales-oriented activities. GSU's data reporting is not reliable and GSU's future direction for DSM cannot be determined with certainty. Staff has no estimate of the effect of GSU's current and future programs on peak-demand and energy consumption.

DSM Adjustments for CPL

Active DSM: CPL anticipates that about 81 percent of its contract interruptible loads are available for interruption at the time of system peak. Staff has adopted CPL's projections (which range from 185 to 325 MW) for the forecast period.

Passive DSM: CPL offers a Good Cents Program, a Centsable (existing home) Program, and a Heat Pump Program. Staff reduced the peak-demand reduction claims of these programs because they appear to overstate the system benefits. The reported energy conservation impacts of all three programs were rejected because CPL has not fully addressed the effect of potential equipment changes due to program implementation. Only two years of adjustments for the Commercial Heating and Commercial Cooking Programs have been included as staff anticipates that these sales-oriented programs will be phased out.

Passive DSM totals 14 MW by 1995 and 27 MW by 2000 in the CPL service area.

DSM Adjustments for CPS

Active DSM: CPS reported 10 MW of interruptible loads which staff has adopted as an adjustment to the service area forecast.

Passive DSM: CPS has recently terminated its conservation programs which had a measurable impact. No adjustments are required.

DSM Adjustments for SPS

Active DSM: Staff has adopted SPS's estimates of the impact of its interruptible load (a municipal pumping customer) and irrigation timing activities through wholesale customers. Although reported at current levels of 16 MW, interruption and scheduling of irrigation pumps have a significant potential to reduce SPS's peak-demand requirements. SPS may control more than 50 MW next season.

Passive DSM: Staff has adopted a portion of the reported impacts for the Energy Efficiency Home and Dual-Fuel Heat Pump Programs. SPS's remaining programs will have little impact on sales or peak-demand as currently designed.

DSM Adjustments for SWEPCO

Active DSM: SWEPCO has two interruptible customers who provide about 48 MW at the time of system peak. Staff has adopted these as adjustments to the service area peak-demand forecast.

Passive DSM: SWEPCO did not provide credible impact data for its passive DSM programs. The reported energy conservation impacts of the programs were rejected because SWEPCO has not fully addressed the effect of potential equipment changes due to program implementation. SWEPCO's programs have no impact on sales or peak-demand as currently designed.

DSM Adjustments for LCRA

Active DSM: The Air Conditioner and Water Heater Cycling Program currently provides about 13 MW in peak-demand reduction potential. LCRA's participation projections appear reasonable. However, staff estimates that the peak kilowatt impact estimation is overstated by as much as 50 percent.

Passive DSM: Commission staff has adopted the remaining projections for the Cooling Efficiency Program, Good Cents Home Program, and Commercial Lighting Program.

Passive DSM totals 32 MW by 1995 and 62 MW by 2000 in the LCRA service area.

DSM Adjustments for COA

Active DSM: The COA anticipates a small peak-demand reduction through direct load control of residential appliances. Staff has adopted this estimate.

Passive DSM: The COA prepared an estimate of the impact of its conservation programs. Staff has adopted this estimate.

Passive DSM totals 113 MW by 1995 and 262 MW by 2000 in the COA service area.

DSM Adjustments for WTU

Active DSM: WTU did not report any interruptible loads.

Passive DSM: WTU has residential and commercial audit programs, an Energy Saver Program Residential, and an Energy Saver Program Commercial. Staff did not include the audit program's savings estimates as adjustments to the forecast. Staff included only a portion of the Energy Saver Program's estimates as an adjustment to the service area forecast because the programs appear to overstate the system benefits.

Passive DSM totals 5 MW by 1995 and 11 MW by 2000 in the WTU service area.

DSM Adjustments for EPE

Active DSM: EPE did not report any interruptible loads.

Passive DSM: EPE projects that a few additional customers will install commercial cool storage during the forecast period. Staff has adopted this forecast as an adjustment to peak-demand. All other programs and activities have an insignificant, non-measurable projected impact.

DSM Adjustments for TNP

Active DSM: TNP reports 2 MW of interruptible irrigation customers. Staff's forecasting methodology does not require this adjustment to peak-demand.

Passive DSM: TNP prepared estimates of the impacts of its two residential programs, the Good Cents Home Program and the High-efficiency Air Conditioner and Heat Pump Program. Staff has adopted these estimates as adjustments to the forecast.

Passive DSM totals 11 MW by 1995 and 22 MW by 2000 in the TNP service area.

DSM Adjustments for BEPC

Active DSM: BEPC did not report any interruptible loads.

Passive DSM: BEPC does not have any passive DSM programs.

The Statewide Potential For Demand-Side Energy Efficiency

During the last few years of the 1980s, the efficiency of electricity use was mentioned in discussions of four national policies: energy security, environmental quality, industrial competitiveness, and economic growth. Most experts agree that the efficiency of electricity usage can make a contribution to these four interrelated goals.

A brief discussion of energy efficiency potential in Texas follows.

Statewide Application of TU Electric's Energy Efficiency Goal

TU Electric has established a goal of satisfying 20 percent of peak-demand growth through conservation and load management programs. This goal is not arbitrary; it is based on TU Electric's achievements during the 1980s. TU Electric has a record of achievement, and it is reasonable to expect that other utilities in the State could achieve a similar peak-demand reduction goal during the forecast period.

For the purpose of comparison with the current demand-side adjustments for passive DSM, a 20-percent-of-growth achievement was calculated for each service area. The Commission staff's unadjusted peak-demand forecasts were used to derive the peak-demand reduction achievements for each service area displayed in Table 5.9. The following table compares the recommended passive DSM adjustment (described above) with the "20-percent-of-growth" scenario in selected years.

Year	Recommended Passive DSM Adjustment[7] (MW)	"20 Percent of Growth" Scenario (MW)	Difference (MW)	Difference (%)
1995	710	1,322	612	86
2000	1,536	3,150	1,614	105

Incidentally, the Commission staff's recommended passive DSM adjustments (reported in Tables 5.10 to 5.43) for TU Electric and COA are within 80 percent of the calculated "20-percent-of-growth" achievement. Based on their current capabilities and intentions, the remaining utilities fall far short of this savings level.

The value of such a direct comparison is somewhat limited. Differences in customer mix, appliance saturations, system economics, and capacity reserves account for some of the differences in these utilities' efforts and achievements in DSM. However, it is the opinion of Commission staff that much of the difference among the state's utilities is attributable to their varying commitments to energy efficiency.

EPRI's Estimates of the Impact of DSM

Several EPRI studies have attempted to estimate the energy savings associated with future energy efficiency improvements and utilities' DSM activities. In 1986, EPRI estimated that by the year 2000, utilities around the nation would save 5.7 percent[8] of total demand through DSM.[9]

In the first of three recent EPRI studies dealing with the impacts of energy-efficient technologies on the U.S. demand for electricity, EPRI estimates that if 100 percent of the most efficient technology available today were adopted by electricity consumers, energy

7 The passive DSM projections from Table 5.1 were reduced by the 1990 estimate (99 MW) to permit a comparison with the scenario.

8 When taking into account additional load-reducing programs such as interruptible and cogeneration, and load building programs, demand and consumption savings are 6 percent and 8 percent of the total respectively.

9 Electric Power Research Institute, "Impact of Demand-side Management on Future Customer Electricity Demand," October 1986, Palo Alto, California, EPRI EM-4815-SR.

consumption could be reduced by 24 to 44 percent in the year 2000.[10] This represents the maximum energy conservation possible through technological improvement. Consumption reductions achievable through DSM depend on the actual technology adoption rate. A second EPRI study[11] estimates that the base forecast of electric energy consumption in the year 2000 is 8.5% lower than it would have been in the absence of any efficiency improvements. Finally, a third EPRI report[12] on this subject reaches the conclusion that, by the year 2000, DSM programs will reduce the U.S. peak electricity demand by 6.7 percent and annual electricity consumption by 3 percent.

The Role of Studies of Conservation Potential

An estimate of the potential for the conservation of resources is a starting point for DSM program selection and planning. Several of the state's utilities have recently contracted for studies of the potential for conservation and load management.

1. COA contracted for a technical audit of its programs in 1986-87 which included suggestions for enhancements of their savings.
2. LCRA contracted for an estimate of conservation and load management potential in 1988-89.
3. EPE contracted for a review of its programs and an estimate of conservation and load management potential in 1988.
4. HL&P contracted for three studies of DSM potential in 1989-90: residential and commercial conservation, residential and commercial load management, and industrial DSM.

Estimates of conservation potential need not be conducted by consulting firms. WTU set up a series of internal working groups to discuss load management potential and has reported this information in its Energy Efficiency Plan. Finally, TU Electric has not undertaken such a study, but the Company's conservation and load management staff examines ways to improve its conservation and load management programs during each annual planning cycle.

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10 Electric Power Research Institute, "Efficiency Electricity Use: Estimates of Maximum Energy Savings," March 1990, Palo Alto, California, EPRI CU-6746.

11 Electric Power Research Institute, "Estimating Efficiency Savings Embedded in Electric Utility Forecasts," August 1990, Palo Alto, California, EPRI CU-6925.

12 Electric Power Research Institute, "Impact of Demand-Side Management on Future Customer Electricity Demand: An Update," September 1990, Palo Alto, California, EPRI CU-6953.

TABLE 5.9

PASSIVE DSM ACHIEVEMENTS SCENARIO BASED ON TU ELECTRIC'S "20% OF GROWTH" GOAL VS. PROJECTED PASSIVE DSM

YEAR	BEPC	COA	CPL	CPS	EPE-Texas	GSU-Texas	HL&P	LCRA	SPS-Texas	SWEPCO -Texas	TNP	TU Electric	WTU	(A)	(B)
1991	11	4	26	21	4	1	22	7	8	10	4	62	4	184	137
1992	19	14	55	44	7	1	59	20	14	20	6	152	8	419	276
1993	28	25	78	66	12	5	98	34	21	31	9	286	13	707	402
1994	35	39	103	87	18	13	153	52	27	44	13	379	19	982	539
1995	41	54	128	109	23	21	233	71	33	57	18	508	26	1,322	710
1996	49	70	147	130	28	28	323	89	39	70	22	640	34	1,667	871
1997	58	85	168	152	32	35	415	108	44	83	29	773	41	2,022	1,035
1998	67	100	190	176	36	41	501	128	50	97	37	901	49	2,372	1,204
1999	75	118	217	204	41	50	604	152	55	110	44	1028	57	2,755	1,371
2000	82	137	244	229	46	58	705	170	61	123	50	1178	66	3,150	1,419

Note:

(A) Passive DSM Scenario "20% Growth". The staff peak-demand forecast for each service area was used to calculate 20 percent of growth in each year. These annual amounts are cumulative starting in 1991.

(B) Projected Passive DSM in Texas. The last column is the "Passive DSM" column from Table 5.1 less the 1990 achievements (99 MW).

TABLE 5.10

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

TEXAS UTILITIES ELECTRIC COMPANY

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	106.0	291.5	75.1	472.6
1991	127.0	330.9	173.7	631.6
1992	149.0	351.1	259.1	759.2
1993	187.0	370.5	320.0	877.5
1994	225.0	392.8	381.6	999.4
1995	254.0	417.1	463.8	1,134.9
1996	282.0	440.5	556.0	1,278.5
1997	307.0	464.8	648.5	1,420.3
1998	332.0	489.2	746.1	1,567.3
1999	332.0	513.6	845.1	1,690.7
2000	332.0	537.9	948.1	1,818.0

TABLE 5.11

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

TEXAS UTILITIES ELECTRIC COMPANY

Year	Residential	Commercial	Industrial	Other	Total
1990	142,583.1	19,324.2	-489.0		161,418.3
1991	218,708.5	118,188.3	1,214.0		338,110.9
1992	292,268.2	231,975.5	5,890.0		530,133.7
1993	350,421.1	312,880.1	6,139.0		669,440.2
1994	407,641.5	394,579.8	6,256.0		808,477.3
1995	463,851.4	497,087.3	9,475.0		970,413.6
1996	526,216.8	611,174.4	14,329.0		1,151,720.2
1997	579,099.4	726,113.8	19,021.0		1,324,234.2
1998	635,820.2	845,804.9	24,367.0		1,505,992.1
1999	668,219.3	969,642.4	29,921.0		1,667,782.7
2000	703,721.9	1,098,915.9	36,017.0		1,838,654.8

TABLE 5.12

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

HOUSTON LIGHTING AND POWER COMPANY

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	-24.0	928.0	3.1	907.1
1991	-17.0	659.3	16.6	659.0
1992	-10.0	638.6	39.9	668.5
1993	1.0	735.9	76.1	813.0
1994	13.0	744.7	120.8	878.6
1995	21.0	764.6	168.3	953.8
1996	30.0	854.6	196.5	1,081.1
1997	37.0	897.6	224.5	1,159.1
1998	45.0	942.6	250.7	1,238.2
1999	45.0	985.6	277.8	1,308.3
2000	45.0	1,021.6	300.8	1,367.3

TABLE 5.13

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

HOUSTON LIGHTING AND POWER COMPANY

Year	Residential	Commercial	Industrial	Other	Total
1990	55,845.2	-3,284.2			52,561.0
1991	76,740.1	1,019.1			77,759.3
1992	107,809.5	15,994.1			123,803.6
1993	149,151.3	32,815.0			181,966.3
1994	196,089.1	51,161.6			247,250.7
1995	240,797.9	72,507.5			313,305.5
1996	281,614.9	98,683.5			380,298.4
1997	314,378.6	128,750.2			443,128.8
1998	342,019.5	161,520.1			503,539.6
1999	355,563.6	196,993.3			552,556.9
2000	364,620.5	236,829.6			601,450.1

TABLE 5.14

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

GULF STATES UTILITIES COMPANY - TEXAS

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	-14.0	59.0		45.0
1991	-13.0	63.0		50.0
1992	-12.0	63.0		51.0
1993	-9.0	63.0		54.0
1994	-7.0	63.0		56.0
1995	-5.0	63.0		58.0
1996	-3.0	63.0		60.0
1997	-2.0	63.0		61.0
1998		63.0		63.0
1999		63.0		63.0
2000		63.0		63.0

TABLE 5.15

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

GULF STATES UTILITIES COMPANY - TEXAS

Year	Residential	Commercial	Industrial	Other	Total
1990	11,208.0				11,208.0
1991	14,339.0				14,339.0
1992	17,470.0				17,470.0
1993	21,587.0				21,587.0
1994	25,704.0				25,704.0
1995	28,730.0				28,730.0
1996	31,756.0				31,756.0
1997	34,106.0				34,106.0
1998	36,455.0				36,455.0
1999	36,455.0				36,455.0
2000	36,455.0				36,455.0

TABLE 5.16

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

GULF STATES UTILITIES COMPANY - TOTAL

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	-29.0	97.0		68.0
1991	-26.0	83.0		57.0
1992	-23.0	83.0		60.0
1993	-19.0	83.0		64.0
1994	-14.0	83.0		69.0
1995	-10.0	83.0		73.0
1996	-7.0	83.0		76.0
1997	-4.0	83.0		79.0
1998	-1.0	83.0		82.0
1999	-1.0	95.0		94.0
2000	-1.0	95.0		94.0

TABLE 5.17

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

GULF STATES UTILITIES COMPANY - TOTAL

Year	Residential	Commercial	Industrial	Other	Total
1990	22,527.0				22,527.0
1991	28,821.0				28,821.0
1992	35,114.0				35,114.0
1993	43,389.0				43,389.0
1994	51,664.0				51,664.0
1995	57,746.0				57,746.0
1996	63,828.0				63,828.0
1997	68,551.0				68,551.0
1998	73,273.0				73,273.0
1999	73,273.0				73,273.0
2000	73,273.0				73,273.0

TABLE 5.18

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

CENTRAL POWER AND LIGHT COMPANY

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	-23.0	185.0	2.2	164.2
1991	-20.0	231.0	4.4	215.4
1992	-17.0	268.0	7.3	258.3
1993	-12.0	272.0	10.4	270.4
1994	-7.0	277.0	12.4	282.4
1995	-3.0	282.0	14.4	293.4
1996	1.0	287.0	16.6	304.6
1997	4.0	292.0	18.9	314.9
1998	7.0	296.0	21.3	324.3
1999	7.0	301.0	23.9	331.9
2000	7.0	306.0	26.7	339.7

TABLE 5.19

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

CENTRAL POWER AND LIGHT COMPANY

Year	Residential	Commercial	Industrial	Other	Total
1990	23,302.0	-1,028.2			22,273.8
1991	29,784.0	-3,652.4			26,131.6
1992	36,266.0	-3,652.4			32,613.6
1993	44,823.0	-3,652.4			41,170.6
1994	53,379.0	-3,652.4			49,726.6
1995	59,671.0	-3,652.4			56,018.6
1996	65,962.0	-3,652.4			62,309.6
1997	70,856.0	-3,652.4			67,203.6
1998	75,751.0	-3,652.4			72,098.6
1999	75,751.0	-3,652.4			72,098.6
2000	75,751.0	-3,652.4			72,098.6

TABLE 5.20

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

CITY PUBLIC SERVICE BOARD OF SAN ANTONIO

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	14.0	10.0		24.0
1991	17.0	10.0		27.0
1992	20.0	10.0		30.0
1993	25.0	10.0		35.0
1994	30.0	10.0		40.0
1995	34.0	10.0		44.0
1996	38.0	10.0		48.0
1997	41.0	10.0		51.0
1998	44.0	10.0		54.0
1999	44.0	10.0		54.0
2000	44.0	10.0		54.0

TABLE 5.21

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

CITY PUBLIC SERVICE BOARD OF SAN ANTONIO

Year	Residential	Commercial	Industrial	Other	Total
1990	23,302.0				23,302.0
1991	29,784.0				29,784.0
1992	36,266.0				36,266.0
1993	44,823.0				44,823.0
1994	53,379.0				53,379.0
1995	59,671.0				59,671.0
1996	65,962.0				65,962.0
1997	70,856.0				70,856.0
1998	75,751.0				75,751.0
1999	75,751.0				75,751.0
2000	75,751.0				75,751.0

TABLE 5.22

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	4.0	33.0	0.2	37.2
1991	5.0	33.0	0.3	38.3
1992	5.0	33.0	0.5	38.5
1993	7.0	33.0	0.7	40.7
1994	8.0	33.0	0.9	41.9
1995	9.0	33.0	1.1	43.1
1996	10.0	33.0	1.3	44.3
1997	11.0	33.0	1.6	45.6
1998	12.0	33.0	1.8	46.8
1999	12.0	33.0	2.1	47.1
2000	12.0	33.0	2.3	47.3

TABLE 5.23

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Residential	Commercial	Industrial	Other	Total
1990	2,419.8				2,419.8
1991	-844.9				-844.9
1992	-4,366.6				-4,366.6
1993	-8,072.9				-8,072.9
1994	-12,061.3				-12,061.3
1995	-16,893.9				-16,893.9
1996	-22,036.6				-22,036.6
1997	-27,954.9				-27,954.9
1998	-34,217.1				-34,217.1
1999	-41,778.3				-41,778.3
2000	-49,717.5				-49,717.5

TABLE 5.24

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	5.0	33.0	0.2	38.2
1991	6.0	33.0	0.3	39.3
1992	7.0	33.0	0.5	40.5
1993	9.0	33.0	0.7	42.7
1994	11.0	33.0	0.9	44.9
1995	13.0	33.0	1.1	47.1
1996	14.0	33.0	1.3	48.3
1997	15.0	33.0	1.6	49.6
1998	16.0	33.0	1.8	50.8
1999	16.0	33.0	2.1	51.1
2000	16.0	33.0	2.3	51.3

TABLE 5.25

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Residential	Commercial	Industrial	Other	Total
1990	4,394.8				4,394.8
1991	1,841.1				1,841.1
1992	-967.6				-967.6
1993	-3,931.9				-3,931.9
1994	-7,177.3				-7,177.3
1995	-11,475.9				-11,475.9
1996	-16,085.6				-16,085.6
1997	-21,643.9				-21,643.9
1998	-27,545.1				-27,545.1
1999	-35,106.3				-35,106.3
2000	-43,045.5				-43,045.5

TABLE 5.26

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	4.0	45.0		49.0
1991	5.0	45.0		50.0
1992	6.0	45.0		51.0
1993	7.0	45.0		52.0
1994	9.0	45.0		54.0
1995	10.0	45.0		55.0
1996	11.0	45.0		56.0
1997	12.0	45.0		57.0
1998	13.0	45.0		58.0
1999	13.0	45.0		58.0
2000	13.0	45.0		58.0

TABLE 5.27

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Residential	Commercial	Industrial	Other	Total
1990	5,184.0				5,184.0
1991	6,671.0				6,671.0
1992	8,158.0				8,158.0
1993	10,066.0				10,066.0
1994	11,975.0				11,975.0
1995	13,374.0				13,374.0
1996	14,774.0				14,774.0
1997	15,847.0				15,847.0
1998	16,921.0				16,921.0
1999	16,921.0				16,921.0
2000	16,921.0				16,921.0

TABLE 5.28

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	10.0	48.0		58.0
1991	12.0	48.0		60.0
1992	14.0	48.0		62.0
1993	18.0	48.0		66.0
1994	21.0	48.0		69.0
1995	24.0	48.0		72.0
1996	26.0	48.0		74.0
1997	29.0	48.0		77.0
1998	31.0	48.0		79.0
1999	31.0	48.0		79.0
2000	31.0	48.0		79.0

TABLE 5.29

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

Year	Residential	Commercial	Industrial	Other	Total
1990	12,776.0				12,776.0
1991	16,441.0				16,441.0
1992	20,107.0				20,107.0
1993	24,811.0				24,811.0
1994	29,514.0				29,514.0
1995	32,964.0				32,964.0
1996	36,413.0				36,413.0
1997	39,059.0				39,059.0
1998	41,705.0				41,705.0
1999	41,705.0				41,705.0
2000	41,705.0				41,705.0

TABLE 5.30

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

LOWER COLORADO RIVER AUTHORITY

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	11.0	18.8	3.1	32.9
1991	14.0	24.7	8.0	46.6
1992	16.0	30.8	13.6	60.4
1993	20.0	37.2	17.9	75.2
1994	24.0	43.9	24.1	92.0
1995	27.0	50.9	31.8	109.7
1996	31.0	58.1	36.7	125.9
1997	33.0	65.6	43.1	141.7
1998	36.0	70.3	51.0	157.4
1999	36.0	74.5	56.2	166.7
2000	36.0	78.7	61.6	176.2

TABLE 5.31

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

LOWER COLORADO RIVER AUTHORITY

Year	Residential	Commercial	Industrial	Other	Total
1990	15,916.3	1,025.5			16,941.8
1991	23,644.5	2,912.4			26,557.0
1992	31,772.2	4,993.2			36,765.4
1993	46,762.6	7,288.2			54,050.8
1994	47,926.9	9,817.5			57,744.4
1995	62,764.7	12,601.5			75,366.2
1996	76,889.6	15,660.4			92,550.1
1997	76,492.1	19,026.1			95,518.2
1998	83,045.4	22,727.5			105,772.9
1999	87,348.2	26,796.4			114,144.6
2000	89,952.2	31,273.4			121,225.6

TABLE 5.32

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

CITY OF AUSTIN ELECTRIC UTILITY

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990		2.0	13.4	15.4
1991		2.0	29.0	31.0
1992		2.0	47.0	49.0
1993		3.0	65.0	68.0
1994		3.0	85.0	88.0
1995		4.0	113.0	117.0
1996		5.0	143.0	148.0
1997		5.0	174.0	179.0
1998		6.0	205.0	211.0
1999		6.0	235.0	241.0
2000		7.0	262.0	269.0

TABLE 5.33

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

CITY OF AUSTIN ELECTRIC UTILITY

Year	Residential	Commercial	Industrial	Other	Total
1990	23,300.0	14,900.0			38,200.0
1991	54,000.0	36,300.0			90,300.0
1992	89,300.0	56,700.0			146,000.0
1993	129,300.0	74,400.0			203,700.0
1994	180,500.0	91,200.0			271,700.0
1995	242,800.0	120,900.0			363,700.0
1996	308,800.0	152,600.0			461,400.0
1997	378,600.0	187,000.0			565,600.0
1998	445,600.0	224,200.0			669,800.0
1999	507,000.0	263,300.0			770,300.0
2000	562,800.0	301,400.0			864,200.0

TABLE 5.34

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

WEST TEXAS UTILITIES COMPANY

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	5.0		0.8	5.8
1991	6.0		1.7	7.7
1992	7.0		2.6	9.6
1993	9.0		3.5	12.5
1994	11.0		4.4	15.4
1995	12.0		5.4	17.4
1996	14.0		6.3	20.3
1997	15.0		7.3	22.3
1998	16.0		8.4	24.4
1999	16.0		9.4	25.4
2000	16.0		10.5	26.5

TABLE 5.35

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

WEST TEXAS UTILITIES COMPANY

Year	Residential	Commercial	Industrial	Other	Total
1990	6,621.0				6,621.0
1991	8,444.0				8,444.0
1992	10,267.0				10,267.0
1993	12,696.0				12,696.0
1994	15,125.0				15,125.0
1995	16,913.0				16,913.0
1996	18,700.0				18,700.0
1997	20,097.0				20,097.0
1998	21,494.0				21,494.0
1999	21,494.0				21,494.0
2000	21,494.0				21,494.0

TABLE 5.36

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

EL PASO ELECTRIC COMPANY - TEXAS

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	2.0			2.0
1991	2.0			2.0
1992	3.0		0.2	3.2
1993	3.0		0.2	3.2
1994	4.0		0.4	4.4
1995	5.0		0.4	5.4
1996	5.0		0.6	5.6
1997	5.0		0.6	5.6
1998	6.0		0.9	6.9
1999	6.0		0.9	6.9
2000	6.0		1.1	7.1

TABLE 5.37

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

EL PASO ELECTRIC COMPANY - TEXAS

Year	Residential	Commercial	Industrial	Other	Total
1990	2,714.0				2,714.0
1991	3,868.0				3,868.0
1992	5,021.0				5,021.0
1993	6,062.0				6,062.0
1994	7,103.0				7,103.0
1995	7,835.0				7,835.0
1996	8,568.0				8,568.0
1997	9,004.0				9,004.0
1998	9,441.0				9,441.0
1999	9,441.0				9,441.0
2000	9,441.0				9,441.0

TABLE 5.38

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

EL PASO ELECTRIC COMPANY - TOTAL

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	2.0			2.0
1991	3.0			3.0
1992	4.0		0.2	4.2
1993	4.0		0.2	4.2
1994	5.0		0.4	5.4
1995	6.0		0.4	6.4
1996	7.0		0.6	7.6
1997	7.0		0.6	7.6
1998	8.0		0.9	8.9
1999	8.0		0.9	8.9
2000	8.0		1.1	9.1

TABLE 5.39

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

EL PASO ELECTRIC COMPANY - TOTAL

Year	Residential	Commercial	Industrial	Other	Total
1990	3,511.0				3,511.0
1991	5,004.0				5,004.0
1992	6,496.0				6,496.0
1993	7,842.0				7,842.0
1994	9,188.0				9,188.0
1995	10,136.0				10,136.0
1996	11,083.0				11,083.0
1997	11,648.0				11,648.0
1998	12,213.0				12,213.0
1999	12,213.0				12,213.0
2000	12,213.0				12,213.0

TABLE 5.40

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

TEXAS - NEW MEXICO POWER COMPANY

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	6.0		1.0	7.0
1991	7.0		2.5	9.5
1992	9.0		4.5	13.5
1993	11.0		6.7	17.7
1994	13.0		8.8	21.8
1995	15.0		10.9	25.9
1996	16.0		13.1	29.1
1997	18.0		15.4	33.4
1998	19.0		17.6	36.6
1999	19.0		20.0	39.0
2000	19.0		22.3	41.3

TABLE 5.41

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

TEXAS - NEW MEXICO POWER COMPANY

Year	Residential	Commercial	Industrial	Other	Total
1990	8,646.8				8,646.8
1991	12,605.5				12,605.5
1992	16,171.4				16,171.4
1993	19,028.0				19,028.0
1994	21,667.8				21,667.8
1995	23,884.5				23,884.5
1996	26,192.7				26,192.7
1997	27,428.7				27,428.7
1998	28,565.2				28,565.2
1999	27,934.4				27,934.4
2000	27,218.3				27,218.3

TABLE 5.42

CUMULATIVE MEGAWATT IMPACTS AT THE POINT OF GENERATION

BRAZOS ELECTRIC POWER COOPERATIVE, INC.

Year	Exogenous MW	Active MW	Passive MW	Total MW
1990	5.0			5.0
1991	6.0			6.0
1992	8.0			8.0
1993	10.0			10.0
1994	11.0			11.0
1995	13.0			13.0
1996	14.0			14.0
1997	16.0			16.0
1998	17.0			17.0
1999	17.0			17.0
2000	17.0			17.0

TABLE 5.43

MEGAWATT-HOUR IMPACTS AT THE CUSTOMER METER

BRAZOS ELECTRIC POWER COOPERATIVE, INC.

Year	Residential	Commercial	Industrial	Other	Total
1990	6,812.0				6,812.0
1991	8,833.0				8,833.0
1992	10,855.0				10,855.0
1993	13,370.0				13,370.0
1994	15,885.0				15,885.0
1995	17,724.0				17,724.0
1996	19,563.0				19,563.0
1997	20,951.0				20,951.0
1998	22,339.0				22,339.0
1999	22,339.0				22,339.0
2000	22,339.0				22,339.0

CHAPTER SIX

RESOURCE PLAN

Introduction

Resource planning is a critical activity for the electric utility industry. Electric utility resource planning primarily consists of the following activities:

1. Projection of future demand in the service area
2. Estimation of the effect of future self-generation
3. Consideration of demand-side resources and integration of demand-side strategies
4. Determination of alternative utility and non-utility power sources
5. Projection of the generating capacity needed to satisfy uncertain near-term and long-term demand requirements
6. Formulation of reliable generating capacity reserve margin levels and capacity factor goals
7. Selection of reliable fuel resources
8. Planning of capital procurement
9. Design and construction scheduling of power plant and transmission facilities
10. Compliance with regulatory requirements

Electric utilities must try to satisfy various resource planning objectives ranging from the maintenance of system reliability to the environmental consequences of electricity generation, all within the framework of government regulation. Therefore, it is important that utilities look at different options when preparing a resource plan. The preparation of flexible resource plans can prevent the creation or persistence of the excess capacity that many utilities in Texas face today.

The U.S. peak electric energy demand grew at a constant and predictable rate of 7 to 8 percent annually from 1950 to 1973. At the same time, due to improvements in the efficiency of production and economies of scale, electricity prices continued to decline in inflation-adjusted (real) terms. From 1974 to 1985 that picture changed dramatically. Demand growth declined to less than 3 percent per year. A significant increase in electricity prices, mainly due to dramatic increases in oil and natural gas prices of the mid-to late-1970s, was the main reason for the downturn of the trend in electricity consumption. Conservation programs were also important in reducing growth rates in demand for electricity from 1974 to the present time. Despite the lower rate of growth in demand, utilities continued to construct generating capacity. Utilities believed that future growth rates in demand would be similar to those experienced prior to 1974. Many generating units which have come into commercial operation in recent years, as well as those which are about to be completed, were planned in the early- to mid-1970s when the annual growth rates of demand were high.

Due to an obligation to offer reliable service, utilities maintained the high reserve margins to reduce the possibility of shortages in their systems. To satisfy similar reliability concerns, electric utilities diversified their fuel sources. In Texas, the utilities have significantly reduced reliance on natural gas. As a result, electric utilities have continued to add non-gas-fueled units into their base load operations despite the slower demand growth. However, the growth in new proposed capacity has been declining in recent years. This might bring a balance between supply and demand for electricity in the future.

Most of the electric utilities in the U.S. have excess generating capacity. According to the Department of Energy, investor-owned utilities had over $54 billion invested in excess capacity in 1987. If all utilities are included in this calculation, the value of excess capacity may reach nearly $124 billion. Consequently, it is not surprising to see average-sized utilities in the U.S. having reserve margins above 30 percent. In 1989, the installed generating reserve of U.S. utilities as a group was about 27 percent, much higher than the 15 to 20 percent considered adequate for reliability purposes. Calculated reserve margins would be even higher if the demand-reducing impact of interruptible loads was considered.[1]

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1 Several electric resource planning organization (such as the North American Electric Reliability Council) calculate reserve margins without consideration of the impact of interruptible loads. In contrast, it is Commission staff practice to first reduce peak demand by the amount of the interruptible resource then available to calculate reserve margins. Including the impact of interruptible loads reduces the amount of firm demand used for planning purposes. All else equal, the calculated reserve margin is higher under this treatment.

Texas utilities have suffered from the excess capacity problem as well. Generating utilities in Texas had a reserve margin of over 35 percent in 1980. Due to slower additions to capacity, reserve margins for Texas generating utilities declined to about 31 percent in 1987 and 28 percent in 1989. The 1989 reserve margin for Texas, including the demand-reducing impact of interruptible loads, was 33 percent. The statewide reserve margin should decline gradually to about 15.1 percent in 1999 (18.2 percent with the demand-reducing impact of interruptible loads) if the proposed resource plans materialize throughout the state. ERCOT utilities have also had a similar experience during the last ten years and are expected to have a 15.3 percent reserve margin in 1999 (22.9 percent including the impact of interruptible loads) if all proposed member utilities' resource plans materialize.

The proposed reserve margins remain above the minimum levels recommended by ERCOT or other adjoining reliability councils during the next ten years. The need for new supply sources may become apparent by the late 1990s or early in the 21st century. The use of significant resources to build new generating capacity prior to that time would represent a misallocation of resources and very high economic and social costs. To avoid excess capacity, it is crucial for utility planners to achieve a reasonable balance between cost and reliability. The evaluation of conventional and nonconventional capacity resources is appropriate to achieve a reasonable balance. Commission staff has tried to maintain a balance between cost and reliability concerns in deriving the recommended capacity resource plan presented here.

In the remaining sections of this chapter, an analysis of reliability issues is provided. The near-term additions to the stock of generating units and 10-year capacity additions are then analyzed.[2] Alternative capacity resources, including the availability of cogeneration, are described next. The base case capacity resource plan relies on the Commission staff's recommendations for demand-side management programs (Chapter 5), purchases of cogenerated power, purchased power from other utilities, and other alternatives. Finally, alternative resource plans dealing with forecast uncertainties are provided. Commission staff's individual service area capacity resource plans are presented in Appendix A.

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2 The "10-year" forecast and resource plan discussed throughout this report actually covers the period 1990 to 2000 (or 11 years, inclusive). The eleventh year is included to facilitate comparisons with other reports and projections, many of which refer to the year 2000.

System Reliability and Reserve Margins

A review of the reliability of the electric system in Texas is aided by an assessment of national reliability and other factors. A number of organizations are involved in the assessment of the reliability of power production in the United States including the DOE, the Federal Energy Regulatory Commission (FERC), the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association. In addition, the North American Electric Reliability Council (NERC) was founded in 1968 by electric utilities to promote the reliability of their generation and transmission systems. Nine regional reliability councils and one affiliate make up NERC and include virtually all of the electric utility systems in the United States, Canada and the northern portion of Baja California, Mexico. NERC meetings are attended by representatives of the above organizations.

National Reliability Assessment

NERC prepares an annual assessment of reliability. The 1990 assessment includes a finding that the 10-year supply plans of electric utilities were expected to be adequate in most parts of the United States and Canada. However, NERC identified a number of threats to reliability or risks to supply:

1. Environmental impacts due to the passage of the 1990 amendment of the Clean Air Act may have adverse impacts on reliability
2. Demand projection uncertainty and possible under-predictions in demand may result in supply shortfalls
3. Transmission deficiencies in some areas may decrease the reliability of the electrical system
4. Fuel supply uncertainty and the possibility of disruptions in availability and deliverability of natural gas may adversely impact system reliability
5. Too much reliance on short lead-time supply options (less than five years) may inhibit the ability of utilities to implement a specific course of action to insure adequate capacity resources
6. Disincentives to the construction of new generation and transmission facilities (resulting from uncertain regulatory treatment) may cause a decline in system reliability

NERC identified other threats to reliability or risks to supply as secondary to the above. It is important to study the threats identified by NERC and other agencies in the evaluation of the reliability of the electric system in Texas.

Table 6.1 shows the 1989 (actual) and 1999 (projected) capability and generation by fuel type for the U.S. portion of NERC and for Texas.

Texas Reliability Assessment

Texas electric utility service areas are in three of the NERC reliability regions. Reported characteristics are shown in Table 6.2 for 1989 as compared to projections for 1999. The numbers in this table are based on utility projections and are given for comparison purposes. They do not necessarily indicate Commission staff endorsement.

The majority of Texas is included in ERCOT, which has the heaviest dependence on natural gas of the three reliability regions. An estimated 31.8 percent of ERCOT's generation in 1999 is expected to be provided by natural gas-fueled units. Dependence on natural gas in the ERCOT generation mix (over twice the national dependence) represents some reliability concern. Over the short term, the continued surplus natural gas deliverability is expected to result in adequate natural gas reliability in the Texas generation mix. However, if severe winter conditions were to occur, there could be curtailments of gas supplies for generating units. If such curtailments do occur and it becomes necessary to substitute fuel oil for gas, the rated capability of some units will be reduced due to equipment design, pipeline delivery constraints, and/or oil inventories. However, if such a reduction in capability exceeds available reserves, capability may be available from other sources within ERCOT. Generally, natural gas may be a reliable fuel over the next several years, but lower prices lead to reduced exploration and drilling activity which could result in lower natural gas reserve additions. This may impose some uncertainty in the reliability of natural gas in the generation mix, both in terms of price and quantity, over the long term.

An estimated 13 percent of 1999 energy is expected to be provided by nuclear plants. Although nuclear plants nationwide run at relatively low capacity factors compared to other base load units, the reliability of the ERCOT system is not expected to be compromised. Nuclear fuel prices are less sensitive to energy markets since lead times for nuclear material and services make prices and availability more predictable. Although the capital costs are much higher for nuclear plants, the fuel component of total cost is considerably less than for fossil-fueled units.

TABLE 6.1

NATIONAL VS. TEXAS CAPABILITY AND GENERATING FUEL TYPE

	NERC - U.S.		Texas Total	
	1989	1999	1989	1999
Capacity Mix: (%)				
Gas/Oil Fired	27.2	27.8	59.6	55.5
Coal-Fired	43.5	41.2	28.0	32.8
Nuclear	14.6	14.4	5.4	7.8
Hydro	9.9	9.0	0.7	0.6
Non-Utility Generation	2.0	4.2	5.2	2.6
Other(Utility)	2.8	3.4	1.1	0.7
Total	100.0	100.0	100.0	100.0
Capability (1,000 MW)	668.0	765.8	62.4	70.7
Summer Peak Load (1,000 MW)*	523.4	645.9	48.6	61.4
Reserve (%)*	27.6	18.6	28.4	15.1
**	30.9	22.1	33.1	18.2
Generation Mix: (%)				
Gas/Oil-Fired	12.4	13.3	38.3	32.9
Coal-Fired	54.2	52.0	43.5	46.8
Nuclear	20.7	19.7	5.2	10.6
Hydro	8.8	7.3	0.4	0.3
Non-Utility Generation	3.2	6.4	10.4	7.3
Other (Utility)	0.7	1.3	2.2	2.1
Total	100.0	100.0	100.0	100.0
Generation (Billion KWH)	2849.8	3476.2	264.7	331.0

Notes: U.S. figures are derived from different publications by North American Electric Reliability Council.

Texas total data is derrived from the December 1989 Load and Capacity Resource Forecast filings filed by generating utilities under the jurisdiction of the Public Utility Commission of Texas. Texas portions were used for multi-jurisdictional utilities. Texas total Coal-Fired data includes Lignite-Fired units.

* The demand-reducing impact of interruptible loads is not included.

** Demand has been reduced to reflect the impact of interruptible loads.

TABLE 6.2

CAPACITY AND GENERATION BY FUEL TYPE IN THREE RELIABILITY REGIONS SERVING TEXAS

	SOUTHWEST POWER POOL (SPP)		WESTERN SYSTEMS COORDINATING COUNCIL (WSCC)		ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)	
	1989	1999	1989	1999	1989	1999
Capacity Mix: (%)						
Gas/Oil Fired	46.0	46.8	24.5	25.0	62.1	56.1
Coal-Fired	40.0	39.4	23.2	22.7	26.8	32.0
Nuclear	8.7	8.6	9.5	8.7	4.8	8.7
Hydro	3.8	3.8	33.3	31.1	0.6	0.5
Non-Utility Generation	0.2	0.8	5.0	7.5	5.7	2.0
Other(Utility)	1.3	0.6	4.5	5.0	0.0	0.7
Total	100.0	100.0	100.0	100.0	100.0	100.0
Capability (1,000 MW)	66.6	71.2	129.5	136.1	51.9	60.2
Summer Peak Load (1,000 MW)*	49.4	60.4	90.7	108.3	40.4	52.2
Reserve (%)*	34.8	17.9	42.8	25.7	28.5	15.3
**	35.9	20.5	48.7	29.1	33.8	22.9
Generation Mix: (%)						
Gas/Oil-Fired	25.2	26.9	9.2	12.0	39.5	31.8
Coal-Fired	55.2	55.3	35.2	32.6	43.4	46.3
Nuclear	16.0	13.8	13.5	11.2	6.4	13.1
Hydro	2.4	2.1	30.6	26.0	0.3	0.2
Non-Utility Generation	1.1	1.7	8.4	11.6	10.4	8.5
Other (Utility)	0.1	0.2	3.1	6.6	0.0	0.1
Total	100.0	100.0	100.0	100.0	100.0	100.0
Generation (Billion KWH)	243.8	292.8	540.5	642.3	207.3	266.6

Notes: U.S. figures are derived from different publications by North American Electric Reliability Council.

* The demand-reducing impact of interruptible loads is not included.

** Demand has been reduced to reflect the impact of interruptible loads.

Coal-fired units as a percentage of total capacity and generation are expected to remain about the same in the SPP and WSCC and increase in ERCOT over the next ten years. Such coal-fired units are part of the needed diversification of the Texas generation mix and are expected to improve long-term reliability.

Another concern over the reliability of the ERCOT system is the increasing dependence on non-utility generation. The long-term reliability of non-utility generation has not been established since most such facilities have been in service for less than ten years. More recently, concerns have arisen over dispatchability, minimum load constraints, transmission and wheeling, and potential long-term availability. The ERCOT projected use of non-utility generation in 1999 is about 8.5 percent, which is lower than the corresponding figure for the WSCC and higher than the 6.4 percent projected for the U.S. portion of NERC. This is due to the abundance of industries in the Gulf Coast region which have the ability to cogenerate.

Major Texas Generating Utilities Target Reserve Margins

The statewide resource plan is dependent on projected peak demands and target reserve margins for the major generating utilities in Texas. Supply resources must be greater than projected peak demands in order to provide for a reliable electric system. Reliability margins are the amounts by which the net capability (installed capacity plus net available power from other supply sources) exceeds the peak demand adjusted for demand-side resource effects. Reserve margins are typically expressed as a percentage of peak demand while capacity margins are calculated as a percentage of net capability. According to the staff resource plan, the reserve margin for ERCOT is projected to decline from 33.0 percent in 1989 to 19.2 percent in 1999, still providing adequate capacity to meet projected demands. The planned reserve margins provide system reliability by allowing for forced and planned outages of generating units, de-rating of units, differences between projected and actual demand, and other factors. Reserve margins vary among utilities and reliability regions due to different system characteristics (duration of peak load season, outage rates for nuclear, coal-fueled, and other generating units, etc.) and support available from other systems.

The lower capacity margins will reduce the utilities' flexibility to respond to unexpected conditions. One or more of the following conditions could lead to lower-than-expected reserve margins:

1. Higher load growth than projected
2. Capacity additions not completed or used as scheduled
3. Large amounts of non-utility generation not completed or ceasing operation
4. Retrofitting coal units to meet increased environmental standards

The reserve margins (or capacity margins) of different reliability regions vary from year-to-year depending on generation mix, planned capability additions, and other characteristics. As a result, all utilities in Texas may not have the same target reserve margins, although all must meet the minimum required by their reliability councel. The target reserve margins for the major generating utilities are based on each utility's generation mix, planned capacity additions, and other factors discussed in earlier sections.

The target reserve margins used to develop the recommended resource plan were based in part on utility avoided-cost filings while taking into account loss of load probability studies and reliability region criteria. For most service areas these reserve margins are essentially the same as those proposed by the utilities. The long-term target reserve margins for HL&P and TU Electric also take into account the level of dependence on non-utility generation and the addition of large nuclear units. These factors raise the 15 percent ERCOT minimum reserve margin to 18 percent. These reserves are further increased to 20 percent in the first few years of each nuclear unit's operation. This insures reliability while the new technology is being introduced and is subject to higher, immature plant forced-outage rates. The staff target reserve margins are included as Table 6.3.

Existing and Near-Term Capability

The level of existing and near-term (unavoidable[3]) capacity must be considered in resource planning. A listing of the near-term generating units considered unavoidable by Texas utilities for this report is shown in Table 6.4. **The qualification of these units as unavoidable is intended solely for the purposes of this report, and is not intended to prejudge any related future proceedings before the Commission.**

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3 "Unavoidable" capacity is capacity under construction or pursuant to a power supply contract which probably could not be cancelled for economic or other reasons.

TABLE 6.3

STAFF RECOMMENDED TARGET RESERVE MARGINS
(PERCENT)

YEAR	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	COA	WTU	EPE	BEPC	Others	Texas
1989	18.0	20.0	15.3	19.2	15.0	18.0	15.0	15.0	15.0	15.0	27.0	15.0	15.0	17.8
1990	20.0	20.0	15.3	19.2	15.0	18.0	15.0	15.0	15.0	15.0	27.0	15.0	15.0	18.5
1991	20.0	18.0	15.3	18.7	15.0	18.0	15.0	15.0	15.0	15.0	26.0	15.0	15.0	17.9
1992	20.0	18.0	15.3	18.2	15.0	18.0	15.0	15.0	15.0	15.0	25.0	15.0	15.0	17.9
1993	20.0	18.0	15.3	17.9	15.0	18.0	15.0	15.0	15.0	15.0	25.0	15.0	15.0	17.9
1994	18.0	18.0	15.3	17.5	15.0	18.0	15.0	15.0	15.0	15.0	25.0	15.0	15.0	17.1
1995	18.0	18.0	15.3	17.1	15.0	18.0	15.0	15.0	15.0	15.0	24.0	15.0	15.0	17.1
1996	18.0	18.0	15.3	16.7	15.0	18.0	15.0	15.0	15.0	15.0	24.0	15.0	15.0	17.0
1997	18.0	18.0	15.3	16.3	15.0	18.0	15.0	15.0	15.0	15.0	23.0	15.0	15.0	17.0
1998	18.0	18.0	15.3	15.9	15.0	18.0	15.0	15.0	15.0	15.0	23.0	15.0	15.0	17.0
1999	18.0	18.0	15.3	15.4	15.0	18.0	15.0	15.0	15.0	15.0	22.0	15.0	15.0	16.9
2000	18.0	18.0	15.3	15.1	15.0	18.0	15.0	15.0	15.0	15.0	22.0	15.0	15.0	16.9

Note: Reserves for Texas-New Mexico Company (TNP) are provided through standby power contract by other power suppliers.

TABLE 6.4

UTILITY-REPORTED EXISTING AND NEAR-TERM GENERATING UNIT ADDITIONS

Year	Plant	Unit	Location County/State	Reporting Owner	Owner Capability net MW	Primary Fuel	Estimates: Reported $/kW w/o afudc	Estimates: Reported $/kW afudc	Reported Disbursed Cost @ 12/31/89 $/kW afudc
1990	Comanche Peak	1	Somerville/Tx	TU	1,150	Uranium	$3,278	$4,678	$5,321
	TNP One	1	Robertson/Tx	TNP	146	Lignite	$2,276	$2,276	
	DeCordova	ct(1-4)	Hood/Tx	TU	260	Natural Gas	$368	$406	
	Permian Basin	ct(4-5)	Ward/Tx	TU	130	Natural Gas	$368	$406	
	Maddox #3	487	Lea/NM	SPS	10	Natural Gas	$160	$160	
	N/A		N/A	SRG&T	28	Coal			
	N/A		N/A	NTEC	30	Lignite			
	LP&L Cogen	1	Lubbock/Tx	LPL	21	Natural Gas			
1991	TNP One	2	Robertson/Tx	TNP	146	Lignite	$859	$859	$200
1992	J.K. Spruce	1	Bexar/Tx	CPS	498	Coal	$997	$1,147	$320
1993	Comanche Peak	2	Somerville/Tx	TU	1,150	Uranium	$2,669	$3,234	$2,299
1994	N/A	gt(1-4)	Harris/Tx	HL&P	160	Natural Gas	$479	$534	
	R.W.Miller	(4-5)	Palo Pinto/Tx	BEPC	207	Natural Gas			
	N/A			SRMPA	10	Coal			

Note: Filed by utilities, December 1989. PUCT staff-recommended near-term generating unit additions are listed in Table 6.15.

There is potential for delay of J. K. Spruce 1 scheduled by CPS for 1992 due to the current status of this project and the lead time for a 498-MW base load coal unit. Therefore, this unit must be excluded from Table 6.4. As a result, the level of unavoidable net capacity addition between 1990 and 1994 is 3,352 MW.

In August 1987, the Commission granted a Certificate of Convenience and Necessity (CCN) for units 1 and 2 of TNP One but stated that Units 3 and 4 of the application would require further regulatory review. After various challenges to the ruling and court appeals, the case was remanded to the Commission. TNP subsequently withdrew its request for a CCN for Units 3 and 4 and the Commission reaffirmed the CCN for Units 1 and 2. Therefore, Units 3 and 4 are not included in the TNP's near-term capability.

The methods of depreciation used by utilities are evaluated during the course of rate cases and other proceedings. For generating unit life-extension programs to be economically feasible, research pertaining to certain depreciation methods will have to be monitored. Some regulated utilities maintain depreciation information for each individual generating unit, while others do not. Maintaining records by generating unit enables more detailed and accurate evaluation of the remaining life of production plant.

Planned Capacity

When existing generation resources are being used efficiently, the construction of additional conventional power plants is a primary resource alternative. Table 6.5 specifies some of the characteristics of the generating units planned between 1995 and 2000 by electric utilities in Texas. These are in addition to the near-term capability specified in Table 6.4. Based on utility filings, an additional 4,810 MW of coal- and lignite-fueled capacity and about 1,300 MW of gas-fueled facilities (primarily peaking units) are scheduled to be added after 1994. As explained later, however, staff is proposing deferral of some of the proposed units.

Existing and Near-Term Capacity While conventional base load capacity is generally the most expensive supply-side option, utilities believe that it is also generally the most predictable and controllable source of new capacity for generation planning purposes. In fact, with the exception of the nuclear-fuel units currently under construction, the majority of conventional power plants constructed in recent years have been completed on schedule and at very close to budgeted cost.

TABLE 6.5

UTILITY-REPORTED PLANNED GENERATING UNIT ADDITIONS 1995-2000*

Year	Plant	Unit	Location County/State	Reporting Owner	Owner Capability net MW	Primary Fuel	Estimates: Reported $/kW w/o afudc	Estimates: Reported $/kW afudc	Reported Disbursed Cost @ 12/31/89 $/kW afudc
1995	Twin Oak	1	Robertson/Tx	TU	750	Lignite	$1,375	$1,980	$504
	N/A	Conv.	Harris/Tx	HL&P	160	Natural Gas	$1,252	$1,675	
	Base 1	1	N/A	BEPC	288	Natural Gas			
	Repower	1	Lubbock/Tx	LPL	10	Natural Gas	$3,000	$3,000	
	Waste Recovery	1	Lubbock/Tx	LPL	10	Refuse	$5,000	$5,000	
1996	Twin Oak	2	Robertson/Tx	TU	750	Lignite	$824	$1,058	$28
	Repower Rio Pecos	5	Crockett/Tx	WTU	130	Natural Gas	$281	$321	
	Malakoff	1	Henderson/Tx	HL&P	645	Lignite	$1,995	$2,858	$189
	N/A		N/A	MEC	35	Natural Gas			
	N/A		N/A	SRMPA	10	Natural Gas			
	Turbine 1	1	N/A	EPE	70	Natural Gas			
1997	Repower Laredo	2	Webb/Tx	CPL	124	Natural Gas	$355	$417	
	Unspecified		N/A	TU	375	Natural Gas		$814	
1998	Forest Grove	1	Henderson/Tx	TU	750	Lignite	$458	$1,431	$313
	Repower Rio Pecos	6	Crockett/Tx	WTU	130	Natural Gas	$200	$229	
	N/A		N/A	BEPC	200	Lignite			
	Turbine 2	2	N/A	EPE	70	Natural Gas			
	GT(98)	(1-3)	N/A	CPS	140	Natural Gas	$565		
	Malakoff	2	Henderson/Tx	HL&P	645	Lignite	$1,394	$1,780	$6
1999	Repower J.L.B.	1	Higalgo/Tx	CPL	247	Natural Gas	$311	$365	
	FB 400	1	N/A	COA	400	Coal	$1,143	$1,143	

TABLE 6.5

UTILITY-REPORTED PLANNED GENERATING UNIT ADDITIONS 1995-2000*

Year	Plant	Unit	Location County/State	Reporting Owner	Owner Capability net MW	Primary Fuel	Estimates: Reported $/kW w/o afudc	Estimates: Reported $/kW afudc	Reported Disbursed Cost @ 12/31/89 $/kW afudc
	WTU CT	1	N/A	WTU	135	Natural Gas	$406	$478	
	Unspecified		N/A	TU	650	Coal			
	N/A		N/A	LCRA	127	Natural Gas			
	GT (99)	(1-3)	N/A	CPS	210	Natural Gas	$550	$607	
2000	Repower L.C.H.	1	Nueces/Tx	CPL	246	Natural Gas	$313	$368	
	Repower Wilkes	2	Marion/Tx	SWEPCO	438	Natural Gas	$81	$92	
	Repower Wilkes	3	Marion/Tx	SWEPCO	438	Natural Gas	$81	$930	
	SWEPCO CT	1	N/A	SWEPCO	135	Natural Gas	$76	$148	
	Combined 1	1	N/A	EPE	80	Natural Gas			
	Unspecified		N/A	TU	244	Natural Gas			
	Unspecified		N/A	TU	650	Coal			
	J.K. Spruce	2	N/A	CPS	498	Coal			
	N/A			SRMPA	10	Coal			

Note:

* - Filed by utilities, December 1989. PUCT staff-recommended near-term generating unit additions are listed in Table 6.17

In addition to the high capital cost of constructing new base load capacity, a major disadvantage of this option is the relatively long time required for planning and constructing a new unit. Initial decisions regarding the addition of a new coal or lignite-fueled unit must be made at least five to ten years prior to its scheduled commercial operation date to allow for design, permitting, certification, and construction. Moreover, significant expenditures must be committed to pre-construction activities, and deferral costs can become quite high once a project enters the construction phase. These factors will continue to present a major problem for generation planners during the next several years.

Combustion turbines provide for flexibility in resource planning and can be constructed at approximately one-third the cost of, and in less than one-half the time required for, constructing a base load coal-or lignite-fueled unit. Combustion turbines provide quick-start capability for meeting system peak demands and emergencies and can be designed and operated in capacity increments which more closely match system load profiles. A number of the planned combustion turbines are configured to permit future conversion to combined-cycle operation and base load duty. In addition, the uncertainty associated with the recovery of investment in giant base load units has been a factor in utilities' decisions to rely more on less capital-intensive, small gas units for near-term needs.

Nuclear Power Plant Capacity

The integration of nuclear power plants into the generation mix and rate bases of regulated utilities has generated much controversy--to the extent that some utilities see these issues as threats to their financial viability. The unforeseen increases in construction costs and unrealized expectations for nuclear power plants have caused plant cancellations, stretched-out construction schedules, and outright abandonments. The existing and committed nuclear plants of utilities in Texas are not exempt from the criticisms resulting from experiences at Brown's Ferry, Three Mile Island (TMI), and foreign plants. These pressures have contributed to increased regulation, more attention to safety concerns, unplanned construction costs, and lengthy construction delays.

Compared to many other states, Texas is a relative newcomer in the field of nuclear power plant regulation. Predicting the reliability and efficiency of the Texas plants offers a challenge since Texas does not benefit from first-hand experience that is directly comparable to its experience with fossil-fueled plants. Although much information can be derived from other states, each nuclear unit is different and may not be directly comparable for predicting future plant performance. Before comparisons with similar nuclear plants can be made, new units must first reach mature status. In general, this means about three years of operation and at least two complete refueling cycles. In recognition of the potential reliability problems with immature units, primary owners are permitted to increase their planning reserve levels to compensate during the immaturity period.

Many licensing problems and other concerns have been overcome for the South Texas and Comanche Peak nuclear construction projects since the adoption of the 1988 **Long-Term Electric Peak Demand and Capacity Resource Forecast** report. Both STNP units are on line and unit 1 of Comanche Peak began operation in 1990. The four units of the two projects account for 4,800 MW of the approximate total 6,055 MW of nuclear capacity to be in operation in Texas by 1993. TU Electric's Comanche Peak Unit 2 with a capacity of 1,150 MW is the only Texas nuclear unit under construction. The expected commercial operation date is the summer of 1993.

Capacity Factors. One of the most often used methods of monitoring the performance of a plant is the capacity factor (CF). The capacity factor for a nuclear power plant is defined as its actual electrical output divided by the electrical output which would have been obtained had the plant run at its design output level throughout a defined time period, expressed in percent, or:

$$\text{Capacity Factor (\%)} = \frac{\text{(Net Electrical Energy Generated) x 100}}{\text{(Period Hours) x (Net Design Electric Rating)}}$$

Capacity factors are influenced primarily by: 1) how the plant was used, 2) the length of time in commercial operation, 3) the characteristics of utility management of the plant, and 4) the power plant configuration. Some of these considerations are fixed and cannot be altered without a major effort. Others may be continually changing. These factors are explained more thoroughly below:

1. In the United States, nuclear units are normally used as base load plants. Their high capital cost, relatively low fuel costs, large capacity, and the length of time needed to bring them on line, dictates steady-state base load applications. This is also expected for nuclear units located in Texas.
2. The age of the plant and the length of time a unit has been in commercial operation is important. As described in the testimony presented for HL&P (Docket No. 8059), a mature plant (over four years of

commercial operation) is expected to have all "bugs" worked out and required alterations and modifications completed. In addition, the managers and operators are expected to attain confidence and skill in operating the unit. This factor can change daily.

3. Utility management has a large impact on the realized capacity factor. The officers, managers, and operators are both cause and effect on such areas as maintenance, training, hiring practices, employee skills, and system planning. Aggressive managers, in pursuing efficient operation, will clearly affect the capacity factor. In addition, plant management establishes a reputation with regulatory agencies (including the Nuclear Regulatory Commission (NRC) at the national level as well as the Texas Commission at the state level), with the local community, and with utility ratepayers. These factors tend to change very slowly.
4. Plant configuration has a large effect on the capacity factor. Such things as the size and complexity of the design, the congestion of the plant layout, the degree of flexibility allowed for the plant operations, and the local climate conditions (temperature and weather extremes) may influence operation efficiency. These factors tend to remain stable.

Currently, Texas is served by seven operating reactors. In addition to the operational plants, one unit is in the construction stage. These units are discussed below:

GSU's River Bend, Unit 1 (RB1). River Bend is a boiling water reactor (BWR) located near a bend in the Mississippi River just south of Saint Francisville, Louisiana, and about 28 miles north of Baton Rouge. RB1 entered commercial operation on June 16, 1986, with a nominal generating capacity of 940 MW.

GSU owns a 70 percent share (658 MW) of RB1, and Cajun Electric Power Cooperative owns a 30 percent share. GSU's reported capacity factor as of 1990 is 67.5 percent (cumulative).

EPE's Palo Verde Nuclear Generating Station (PVNGS), Units 1, 2, and 3. Each of these pressurized water reactors (PWR) has a nominal operating capability of 1,270 MW. Their commercial operation beginning dates and cumulative capacity factors through September 1990 are:

Commercial On:	Unit:	Capacity Factor:
January 28, 1986	Palo Verde Unit 1	41.8
September 19, 1986	Palo Verde Unit 2	57.7
January 8, 1988	Palo Verde Unit 3	60.3

It should be noted that the current low capacity factor of Unit 1 was affected by a refueling and maintenance outage which began on April 8, 1989 and continued for 472 days.

As a participant in the PVNGS, EPE owns a 15.8 percent undivided interest in Units 1 & 3. Although EPE sold its 15.8 percent share in Unit 2, it still receives power from that unit through a sales-lease arrangement.

HL&P, CPL, CPS, and COA's South Texas Nuclear Project (STNP), Units 1 and 2. Unit 1 of the STNP (1,250 MW net) went critical on March 8, 1988. On August 25, 1988, HL&P declared the plant to be in commercial operation. Unit 2 of STNP (1,250 MW net) became commercially operational on June 19, 1989.

The ownership of STNP is divided among HL&P (30.8 percent), CPL (25.2 percent), CPS (28 percent), and COA (16 percent). As of September 1990, the cumulative capacity factors for the two STNP units were 60.1 percent and 63.3 percent, respectively.

TU Electric's Comanche Peak Steam Electric Station (CPSES), Units 1 and 2. Unit 1 of CPSES (1,150 MW net) became operational on August 13, 1990. TU Electric is committed to bringing the second unit (1,150 MW net) into operation by the summer of 1993. TU Electric has not identified a firm projected capacity factor for either CPSES unit. In general, however, they anticipate 60 to 70 percent during the maturing years and 72 percent on a long-term basis. After acquiring the shares of the other joint owners, TU Electric is now the sole owner of CPSES.

Nuclear System Reliability. Reliability of the nuclear plants, as indicated by their demonstrated and projected capacity factors, may well prove to be above the average of non-Texas nuclear power plants. The nuclear units will be utilized as base load units thus providing a minimum of plant transient operations. As the plants mature and equipment problems are solved, some increased reliability can reasonably be expected. Nuclear plants have carefully structured and organized maintenance and surveillance programs. In addition, operator training and qualification programs receive concentrated attention by management and the NRC. Improvements in the planning and execution of refueling outages are available and will be used by the utilities. Management is strongly motivated to achieve safe and consistent reliable service.

Programs for monitoring utility activities in these areas are projected for implementation by the Commission staff and should assist in maintaining a high level of nuclear power plant reliability. The use of nuclear fuel within the utilities' generation mix may also improve their overall system operational reliability if some disruption of fossil fuels should occur. In this forecast and resource plan, an average CF of 70 percent for nuclear units is used.

Unit Life Extension and Efficiency Improvements

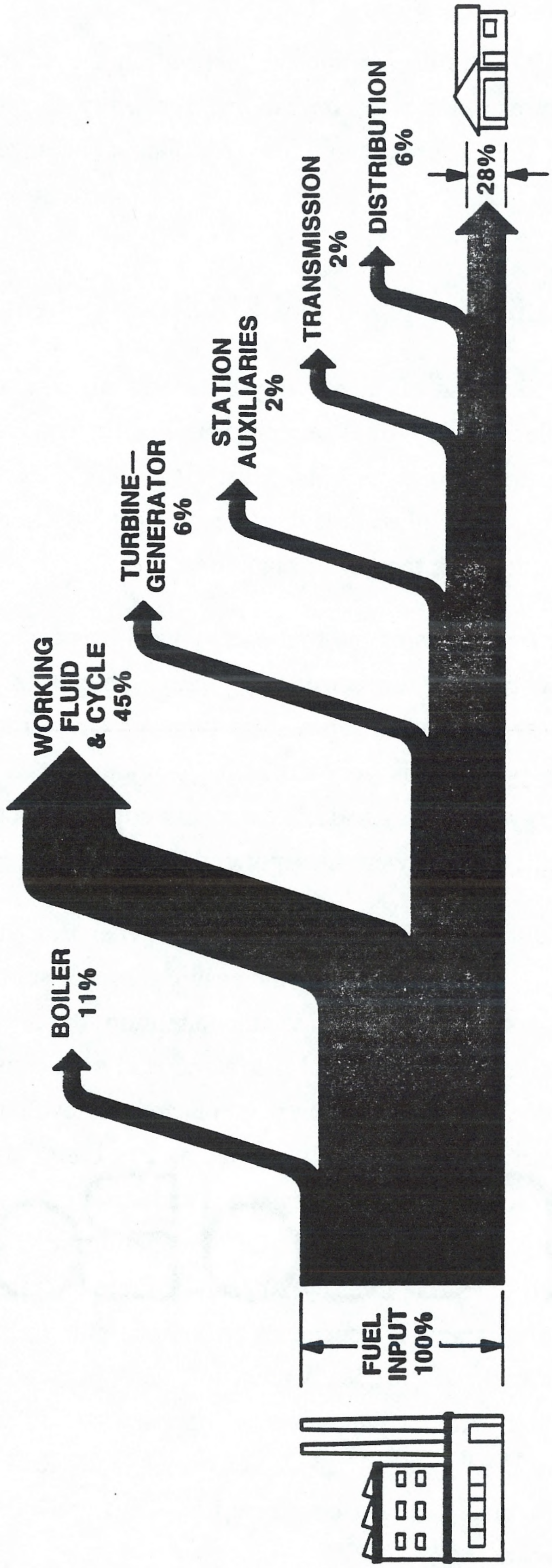
The life extension and efficiency improvements of generation units are reported in the utility-controlled (supply-side) section of utility Energy Efficiency Plans. An overview of these programs shows that the most frequently filed option concerns power plant programs. Figure 6.1 illustrates that the greatest losses, hence the greatest opportunity for improvements, is in the power plant area.

Usually, over two-thirds of the fuel energy used by utilities to produce electricity is lost by the time it reaches the consumer. Improvements in power plant efficiencies and reductions in system losses represent a large potential for savings, but quantifying the extent of this potential is very difficult. Although staff reviewed the utility-reported effects of energy efficiency and life extension improvements, a thorough analysis was not done. The utility filings were incorporated into the resource plan.

Generation Units Extending the life of generating units is a potentially significant option for increasing resource supplies during the next ten years. This option has received considerable attention by utilities over the last few years primarily because of the financial risk associated with constructing new base load power plants. Much research has been conducted to evaluate cost-effective methods of extending generating unit life. By replacing key boiler and turbine components, adding new plant control and diagnostic systems, and initiating improved maintenance practices, the availability and efficiency of older generating units can be vastly improved while extending their operating lives by 20 years or more. While the costs associated with such life extension programs is dependent on various unit-specific factors, they are estimated to range between 20 to 50 percent of new plant construction costs and can be accomplished in one to two years as opposed to the four to six years required for constructing a conventional base load power plant. Repowering of some of the retired gas units is a viable option considered by CPL and other electric utilities during the coming ten years.

FIGURE 6.1

TYPICAL ENERGY LOSSES FROM UTILITY TO CONSUMER



Primarily, gas-fueled capacity scheduled to be retired over the next ten years appears to be a significant source of capacity, particularly if natural gas costs continue to remain relatively low and stable and technological advances in evaluating and applying this option continue to be made. The technology demonstrated under DOE's Innovative Clean Coal Technology Program has potential for the life extension of gas-fueled facilities. Through this program, SPS had planned to install a circulating fluidized bed (CFB) boiler to replace a gas-fueled boiler at its 250 MW Nichols Station, Unit No. 3. This was expected to demonstrate the technical and economic feasibility for other applications in Texas. The proposed CFB technology was a scaled-up version of the technology to be demonstrated at TNP One Units 1 and 2. However, in late December 1990, SPS announced they had abandoned the project.

Transmission and Distribution Transmission and distribution (T&D) facilities offer opportunities for increased efficiency of system operation and cost savings for ratepayers. T&D systems account for a significant amount of the total energy lost in the provision of electric service. Optimization of T&D systems can help control these losses. In addition, significant efficiency improvement opportunities exist in the replacement of older, less efficient T&D equipment and in the control of voltage to minimize line losses. The most significant recent development in this area is the increased availability of economical software and hardware capable of performing optimization studies. This has allowed many smaller utilities, such as small cooperatives, to do a better analysis of their T&D systems.

Current and Future Transmission Projects

Transmission system capability and reliability assessment requires large amounts of information and sophisticated computer models. Because these expensive resources are not currently available to the Commission staff for independent analysis of transmission needs, each new project is evaluated case-by-case as the utilities apply for CCNs. The number of applications for transmission line CCNs has increased substantially in the current calendar year. As of December 1990, 31 applications have been approved. The majority of new construction is for 138 KV lines followed by 69 KV lines. As shown in Figure 6.2, electric cooperatives account for over one-half of the CCN approvals in 1990.

Information on current and future transmission projects is obtained from the utilities' December 1989 **Load and Capacity Resource Forecast** filings. A summary of utility-filed transmission projects appears in Table 6.6. Totals show approximately 150 miles of 500 KV, 667 miles of 345 KV, 23 miles of 230 KV, 1,062 miles of 138 KV, 19 miles of 115 KV, and 456 miles of 69 KV. Construction costs for these projects during the next decade are estimated to exceed $820 million.

Security of Fuel Supply

Because fuel is required for electricity production, generating utilities assign a high priority to fuel supply security as shown by the amount of fuel committed under long-term contracts. Table 6.7 indicates the percentage of each major type of generating fuel currently committed to contract and the overall targets for contract purchases by the state's utilities. Of course, targeted contract purchases of less than 100 percent simply indicate that the utilities intend to maintain some flexibility in future supply mix. Flexibility in procurement and generation is constrained if the amount of a particular fuel or fuel source already committed to purchase is too high. Also, currently contracted amounts decline over time as current contracts expire. In times of relatively stable fuel supplies, there is little need to commit to fuel contracts far into the future.

Negotiation of reasonable and necessary contract terms and conditions is the method preferred by utilities to secure fuel supplies. Many Texas utilities have contracted for virtually 100 percent of the coal for base load, coal-fueled stations and the transportation required from where it is mined. However, some spot coal purchases are made when supplemental quantities are required. Currently, all lignite plants in Texas are located adjacent to the mines which supply their fuel; thus virtually 100 percent of their fuel requirements are committed to long-term contracts. At coal and lignite generating plants, fuel stockpiles provide an additional hedge against short-term fuel supply disruptions.

FIGURE 6.2

TRANSMISSION LINES APPROVED
1990*

	345 KV		230 KV		138 KV		115 KV		69 KV			
	Miles	No. of Dkts.	Miles	No. of Dkts.	Miles	No. of Dkts.	Miles	No. of Dkts.	Miles	No. of Dkts.	Total Miles	No. of Dkts.
IOU	17	1	0	0	92	14	1	1	36	7	146	23
COOP	0	0	3	1	58	4	0	0	30	3	91	8
Total	17	1	3	1	150	18	1	1	66	10	237	31

	2-3 Miles	3-10 Miles	11-25 Miles
Number of Dockets	14	7	(Longest ~ 24 Miles)

* As of December 1990

TABLE 6.6

Major Transmission Line Construction Projects

Project Name		Counties	Voltage (KV)	AC/DC	Length (miles)	Total Cost	Construction Dates Begin	Construction Dates Complete
TU								
	Loop the West Weatherford-Calmont Line into North Texas (BEPC)	Parker	69	AC	0.5	$607,000	Jan-92	May-92
	Monticello-Welsh (SWEPCO)	Titus	345	AC(DC)	16		Feb-93	Jun-94
	Centerville-McCree (TMPA)	Dallas	345	AC	17.4		1990	
		Tarrent	138	AC	12.7		1990	
	Loop the (LCRA) Elgin-McNeil Line into Pflugerville	Travis	138	AC	24	$3,069,000	Jan-91	May-92
	Four county circuit	Johnson,Tarrant Parker.Somervell	345	AC	40.7		1991	
		Ector, Crane	138	AC	27		1991	
		Smith	138	AC	16.5		1991	
	Tarrant West-Hilltop (BEPC)	Tarrant,Parker	138	AC	10		Jan-97	May-98
		Midland,Andrews	138	AC	40		1992	
		Collin	138	AC	2.4		1993	
	Watermill-Limestone (HL&P)	Freestone,Ellis Navarro,Dallas Limestone	345	AC	88	$50,939,000	May-92	May-94
		Collin	138	AC	20		1994	
	Centerville-McCree (TMPA)	Dallas	345	AC	2		1994	
HL&P								
	Salem-Zenith	Austin,Harris Waller,Washington	345	AC	46	$102,000,000	To be determined	
	Malakoff; Loop Forest Grove-Trinidad	Henderson	345	AC	2.5	$13,000,000	Sep-94	Dec-96
GSU								
	Line 760	Iberville,St. Martin Lafayette,St. Landry Acadia	500	AC	61	$56,000,000	Jun-93	Jun-96
	Line 560	Hardin,Jefferson Liberty,Harris Montgomery	500	AC	88	$76,000,000	May-97	May-00
	Line 88	Jefferson	138	AC	12.6	$2,100,000	Jun-92	Jun-93
	Line 197	Newton,Orange	230	AC	25	$2,500,000	Apr-94	Apr-95
	Line 415	Polk	138	AC	12	$2,100,000	Jun-96	Nov-97
	Line 586	Montgomery	138	AC	10	$900,000	Apr-97	Apr-98
CPL								
	Pharoah	Nueces	138	AC	1.7	$1,179,000	Jan-91	May-91
	South Padre	Cameron	138	AC	8.5	$15,400,000	May-91	Sep-91
	Santo Nino	Webb	138	AC	3.2	$2,370,000	Jan-91	May-91

TABLE 6.6

Major Transmission Line Construction Projects

Project Name		Counties	Voltage (KV)	AC/DC	Length (miles)	Total Cost	Construction Dates Begin	Construction Dates Complete
	Lon Hill-Coleto	Goliad,Bee,Nueces, San Patricio	345	AC	73	$33,000,000	Jun-91	May-92
	Northeast Fulton	Aransas	69	AC	4.3	$1,449,000	Jan-92	May-92
	Edinburg - LaPalma	Cameron	345	AC	25	$12,900,000	Jan-93	Oct-93
	Batesville - Eagle Pass	Maverick,Zavala	138	AC	55	$8,333,000	Jul-93	May-94
	Transmission Tie (SWPP)			DC		$27,663,000		Mar-95
CPS								
	Project 280	Bexar	138	AC	8.2	$3,219,883	To be determined	
	Project 605	Bexar	138	AC	3.9	$554,894	To be determined	
	Project 770	Bexar	138	AC	0.5	$759,013	Mar-91	May-91
	Project 158	Bexar	138	AC	0.1	$580,350	Nov-90	Jan-91
	Project 479	Bexar	138	AC	0.1	$598,566	Mar-92	May-92
	Project 722	Bexar	345	AC	37	$16,833,400	Jun-90	Nov-91
	Project 810	Bexar	345	AC	0.5	$2,175,214	Sep-91	Nov-91
	Project 898	Bexar	138	AC	1.8	$1,579,390	Dec-91	May-92
	Project 071	Bexar	138	AC	1.4	$767,664	Jan-93	May-93
	Project 796	Bexar	138	AC	2.2	$423,508	Jan-93	May-93
	Project 074	Bexar	138	AC	3.5	$1,347,017	Nov-92	May-93
	Project 705	Bexar	138	AC	4.9	$2,202,028	Oct-93	May-94
	Project 338	Bexar	138	AC	0.5	$776,303	Dec-94	May-95
	Project 302	Bexar	138	AC	0.1	$559,266	Mar-96	May-96
	Project 473	Bexar	138	AC	0.2	$703,043	Dec-95	May-96
	Project 836	Bexar	138	AC	0.1	$549,858	Mar-96	May-96
	Project 596	Bexar	138	AC	14.8	$16,310,286	Jul-96	May-97
	Project 497	Bexar	138	AC	10.3	$11,640,915	Aug-97	May-98
	Project 746	Bexar	138	AC	4.2	$1,498,763	Oct-97	May-98
	Project 757	Bexar	138	AC	5.8	$2,083,293	Sep-98	May-99
	Project 757	Bexar	138	AC	11.4	$4,188,013	Aug-98	May-99
	Project 757	Bexar	138	AC	3.4	$2,125,111	Dec-98	May-99
	Project 712	Bexar	345	AC	19.5	$12,038,803	Feb-99	May-00
SPS								
	Chaves Co. - Urton	Chaves	115	AC	4.5	$999,400	Mar-91	Jun-91
	Tolk - Eddy Co.	Eddy,Lamb,Bailey Roosevelt,Chaves	345	AC	157	$36,900,000	To be determined	
	Urton - Roswell City	Chaves	115	AC	2.7	$550,000	Feb-92	Apr-92
	Roswell City - Roswell Interchange	Chaves	115	AC	3.8	$320,000	Mar-92	May-92
	Lamb Co. - Carlisle	Lamb,Hockley,Lubbock	347	AC	39	$3,480,000	Nov-92	Apr-93
	East Pandhandle-Bowers	Grey	115	AC	4.4	$2,710,000	Feb-94	Jun-94

TABLE 6.6

Major Transmission Line Construction Projects

Project Name	Counties	Voltage (KV)	AC/DC	Length (miles)	Total Cost	Construction Dates Begin	Construction Dates Complete
SWEPCO							
Beckville - N.W. Henderson	Rusk,Panola	69	AC	23.2	$1,139,000	Oct-91	Jun-91
Beckville - Rockhill	Panola	69	AC	4.1	$178,000	Oct-93	Jun-94
Dekalb - New Boston	Bowie	69	AC	13.2	$532,000	Oct-91	Jun-92
Hooks - Red River	Bowie	69	AC	4	$339,000	Feb-91	Jun-91
Jefferson - Superior	Marion	69	AC	21.7	$984,000	Oct-94	Jun-95
Jefferson - Lieberman	Marion	138	AC	28	$1,976,000	Oct-96	Jun-97
Karnack - Woodlawn	Harrison	69	AC	3.7	$511,000	Jan-95	Jun-95
Knox Lee - Monroe	Rusk	138	AC	6.4	$765,000	Jan-93	Jun-93
Know Lee - Rock Hill	Rusk,Panola	138	AC	10	$737,000	Jan-98	Jun-98
Longwood - Marshall	Harrison	138	AC	22.2	$1,263,000	Oct-91	Jun-92
Marshall - Jefferson	Harrison	69	AC	17	$902,000	Oct-93	Jun-94
Marshall - Rock Hill	Harrison, Panola	69	AC	17.7	$1,361,000	Oct-93	Jun-94
Monroe Corner - Overton	Rusk	138	AC	17.5	$2,245,000	Oct-94	Jun-95
Mt. PLeasant - Petty	Titus	69	AC	2.1	$123,000	Feb-95	Jun-95
New Boston - Red River	Bowie	69	AC	3.9	$327,000	Feb-92	Jun-92
North Mineola - Quitman	Wood	138	AC	9.4	$3,132,000	Jan-92	Jun-98
N. W. Henderson - Overton	Rusk	138	AC	7.3	$1,926,000	Jan-98	Jun-96
Petty - Pittsburg	Camp,Titus	138	AC	9.7	$2,401,000	Jan-96	Jun-96
Pittsburg - Winnsboro	Camp,Franklin,Wood	138	AC	20	$5,090,000	Oct-96	Jun-97
Rock Hill - S. Shreveport	Panola	138	AC	27.4	$2,825,000	Oct-95	Jun-96
S.E. Longview - Whitney	Gregg	69	AC	2.6	$283,000	Feb-91	Jun-91
Welsh - Monticello	Titus,Camp	345	AC	16	$4,768,000	Feb-93	Jun-94
LCRA							
Winchester - Salem	Fayette,Washington	138	AC	35	$1,800,000	To be determined	
Lampasas	Lampasas,San Saba Mills	69	AC	52	$4,100,000	To be determined	
Ferguson-Buchanan	Burnet,Llano	138	AC	16	$2,600,000	Mar-91	Oct-91
Kerr County	Kerr	138	AC	4	$2,000,000	Sep-91	Jan-92
Fredericksburg	Gillespie	138	AC	4	$2,300,000	Dec-91	Apr-92
Pisek	Fayette,Colorado Washington,Austin	69	AC	22	$2,200,000	Feb-94	Sep-94
COA							
987	Caldwell,Travis	138	AC	17	$22,314,950	Apr-90	Jun-91
974/975	Travis	138	AC	5	$6,091,800	Jan-90	Jan-91
976	Travis	138	AC	4	$6,657,700	Jan-90	Aug-91
978/980	Travis	138	AC	4	$887,300	Apr-90	Nov-91
965	Travis	138	AC	4	$2,074,308	Sep-90	Apr-91
West loop	Travis	138	AC	26.5	$2,191,600	To be determined	

TABLE 6.6

Major Transmission Line Construction Projects

Project Name	Counties	Voltage (KV)	AC/DC	Length (miles)	Total Cost	Construction Dates Begin	Construction Dates Complete
WTU							
Alpine- Ft. Davis	Brewster,Jeff Davis	69	AC	28.5	$1,744,000		Dec-92
Tap #092 - Bronte	Coke	138	AC	3.8	$266,000		Aug-92
Brady Plant - Bardy So.	McCulloch	69	AC	2.5	$224,000		Aug-92
Barilla - T.U. Permian	Ward	138	AC	53.5	$3,690,000		Dec-92
Tap #069 - S. Clyde	Callahan	138	AC	6	$761,000		Aug-93
Mulberry - Red Creek	Taylor,Runnels,Coke, Tom Green	345	AC	87	$16,308,000		Aug-94
Sonora - Menard	Menard,Schleicher Sutton	138	AC	59	$4,487,000		Aug-95
L. Pauline - Vernon SW	Hardeman,Wilbarger	138	AC	28.5	$2,530,000		Aug-95
Alamito Ctr. - Presidio	Presidio	69	AC	60	$3,646,000		Aug-96
L. Pauline - Childress	Hardemand,Childress	138	AC	37	$3,646,000		Aug-97
E. Munday - Rule	Knox,Haskell	138	AC	31	$3,117,000		Aug-98
Abilene S. - Tuscola	Taylor	138	AC	11	$2,324,000		Aug-99
EPE							
Rio Grande - Dyer	El Paso	69/115	AC	7	$432,000	To be determined	
Chevron	El Paso	115	AC	>1	$1,855,000	To be determined	
El Paso Refinery	El Paso	115	AC	>1	$1,384,705	Sep-90	Jun-91
Chaparral Substation	Dona Ana	115	AC	>1	$393,000	Oct-90	Apr-91
Horizon Substation	El Paso	69	AC	>1	$183,000	Dec-90	May-91
Diablo-Juarez	Dona Ana,Chihuahua	115	AC	>1	$510,000	Apr-90	Jan-91
TNP							
Glen Rose - Squaw Creek	Hood,Somervell	69	AC	5	$585,000	Oct-89	1991
TUEC - Squaw Creek Sta.	Somervell	138	AC	8	$2,750,000	1991	1993
Hamilton City	Hamilton	138	AC	25	$720,000	1991	1992
Talco West - Talco	Franklin,Titus	138	AC	4	$940,000	1991	1991
Old Ocean-Phillips #5 (Bundle)	Brazoria	69	AC	1	$53,000	1990	1990
West Col-Phillips #3 (Bundle)	Brazoria	69	AC	10	$830,000	1991	1991
West Col-Old Ocean (Bundle)	Brazoria	69	AC	9	$597,000	1992	1992
138-8 to South Shore	Galveston	138	AC	6	$2,705,000	1992	1992
BEPC							
Gibbons Ck. - Roans Prair.	Grimes	69	AC	8	$1,494,800	Oct-90	Dec-91
Reagor Spgs. - Ferris	Ellis	138	AC	18	$7,965,350	Feb-92	Jun-92
Windsor S. W. - Gatesville	Coryell,McLennan	138	AC	21	$7,369,150	Feb-93	Jun-93
Bartonsville	Denton	138	AC	14	$21,909,000	Feb-94	Jun-94
LPL							
3rd Intertie	Lubbock	230	AC	10	$6,000,000	Jan-94	Jan-95
MEC							
Uvalde Switch Autotransformer	Uvalde	138/69	AC	N/A	$2,366,666	1993	

TABLE 6.6

Major Transmission Line Construction Projects

Project Name	Counties	Voltage (KV)	AC/DC	Length (miles)	Total Cost	Construction Dates Begin	Construction Dates Complete
Rio Grande City - San Isidro	Starr	138	AC	58	$6,546,632	1994	
STEC							
Bay City Tie	Matagorda	138	AC	7	$5,321,000	1990	1991
3 - Oaks	Karnes	69	AC	5	$863,000	1992	1992
Orange Grove - Driscoll	Jim Wells,Nueces	138	AC	30	$7,879,000	1992	1993
Danevang - El Campo	Wharton	138	AC	16	$5,577,000	1992	1993
Pt. Lavaca Tie	Calhoun	69	AC	1	$1,239,000	1993	1993
Mathis - West Station	San Patricio	69	AC	22	$2,606,000	1993	1993

TABLE 6.7

FUEL REQUIREMENTS PLANNING
BY TEXAS UTILITIES
(PERCENT)

	Natural Gas		Coal		Lignite	
Year	Currently Under Contract	Targeted Contract Purchases	Currently Under Contract	Targeted Contract Purchases	Currently Under Contract	Targeted Contract Purchases
1989	58.8	40.0	95.7	78.3	100.0	100.0
1990	59.0	60.4	84.6	79.8	93.6	98.6
1991	58.7	62.5	75.4	69.6	93.6	98.6
1992	50.2	62.1	75.2	68.9	93.6	98.6
1993	31.0	58.6	75.4	79.6	93.6	98.6
1994	28.6	58.3	74.9	79.3	93.6	98.6
1995	19.2	58.8	72.9	79.4	93.6	98.6
1996	19.0	58.9	70.6	79.8	93.6	98.6
1997	19.3	59.6	69.4	86.8	93.6	98.6
1998	19.7	60.1	69.3	87.0	93.6	98.6
1999	19.2	60.1	70.0	87.3	93.6	98.6
2000	15.6	57.1	68.8	88.5	93.6	98.6

Several factors could significantly impact the availability of natural gas in Texas during the next ten years. First, a substantial quantity of gas-fueled generation has been displaced by recently added nuclear capacity. More will be displaced through 1993. Second, the future use of gas-fueled generation will be slowed by the expected construction of base load coal and lignite-fueled units. Gas will continue to fuel intermediate and peaking, rather than base load, requirements. Third, although world tensions have periodically driven up the price, low residual fuel oil prices offer an inexpensive substitute. Unless events occur which permanently affect the supply of crude oil in the Middle East, market forces should moderate the price of oil in the longer term.

Another factor that may impact the availability of natural gas is the 1990 amendments to the Clean Air Act. Natural gas is a cleaner-burning alternative to other fossil fuels, so demand for gas may increase. However, it is not clear to what extent this might occur. There are other alternatives to reducing emissions that can also be implemented. Examples of these alternatives are construction of power plants which use "next-generation" combustion technology (such as fluidized-bed combustion), conversion of coal to synthetic oil or gas prior to use in a power plant, or adding emission control equipment to conventional coal-fueled power plants. Overall, there should be little concern about the future supply of natural gas. It is available now in adequate quantities and at a relatively low price. Reserves can be replaced at only modest increases in price. Finally, natural gas is being touted as the future fuel of choice because of its clean-burning characteristics, indicating confidence in its long-term availability.

Due to the radically different manner in which nuclear fuel is used to produce electricity, utilities must address the security of nuclear fuel supply differently than they address fossil fuel needs. Whereas fossil fuel plants require a continuous feed of fuel, nuclear power plants operate in a batch mode. Fuel is loaded, then consumed over one to two years--after which time the reaction is stopped, the spent fuel removed, a fresh batch of fuel loaded, and the cycle starts again. Because nuclear power plants do not require a continuous input of fuel into the reactor and the fuel loaded into the reactor lasts for at least one year, nuclear power plants are not generally subject to short-term supply disruptions.

Nuclear power plants do experience fuel-supply disruption risks but they are different from those experienced by fossil-fueled plants. Because a long lead time and many processing steps are required to convert milled uranium ore into fabricated fuel bundles, utilities must plan fuel bundle manufacture and delivery very carefully. A delay at any step along the manufacturing process can result in a lack of fresh fuel at the time of a reload. Under current market conditions and inventory levels, utilities should not experience any delays due to unavailable reloads.

Some utilities have developed their own captive fuel resources, notably utility-owned lignite reserves and some minor, utility-owned gas producing wells. However, only TU Electric (through its Texas Utilities Mining Company subsidiary) has successfully operated large-scale fuel-production facilities. TU Electric's lignite mining operations make it one of the largest coal and lignite producers in the nation.

Through effective contracting, fuel diversification, and sound inventory practices, utilities in Texas should be relatively immune from severe fuel disruptions. No physical reasons exist for long-term interruption of their fuel supply; however, rail or mine strikes as well as short-term natural gas curtailments are always possible.

Texas Cogeneration Industry

Cogeneration is a significant source of electric energy in Texas. A cogeneration facility is defined by FERC rules as equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial or commercial heating or cooling purposes by the sequential use of the energy. In recent years, most industrial cogeneration in Texas has been produced by units granted Qualifying Facility (QF) status, a certificate awarded under enactment of the federal Public Utility Regulatory Policies Act of 1978 (PURPA). Under Texas law, such federally-certificated QFs are generally excluded from being a public utility which would be subject to the regulatory overview of the Texas Commission. As shown in Table 6.8, there is, as of December 1989, some 7,117 MW of cogenerated capacity in the state, with an additional 73 MW under construction. Approximately 10.4 percent of the MWH generated in the state in 1989 was supplied by cogenerators (Figure 6.3). Cogeneration, in Texas, is primarily gas-fired turbines (Figure 6.4).

TABLE 6.8

COGENERATION AND SMALL POWER PRODUCTION IN TEXAS
STATUS OF PROJECTS, 1990

Utility Service Area	Existing Capacity	Under Construction	Proposed
COA	110.2	1.0	--
COOP	--	--	400.0
CPL	604.0	38.0	340.0
EPE	20.5	--	--
GSU	897.3	--	--
HLP	3733.9	34.2	--
MUNI	38.5	--	7.5
SPS	126.7	--	--
SWEPCO	140.0	--	--
TNP	689.0	--	30.0
TU	752.1	--	50.0
WTU	5.0	--	--
TOTAL	7,117.2	73.2	827.5

Note: The 7,117.2 MW total capacity of projects in operation in this Table represents an increase of 1,843.8 MW from the previous Load Forecast Report. (In that report, the total capacity in operation was 5,273.4 MW.) Of the 1,843.8 MW increase, only 885.5 MW are from completion of projects under construction. The remaining 958.3 MW are from existing projects that were not in the prior report database.

FIGURE 6.3

STATEWIDE GENERATION MIX
1989 MEGAWATT-HOURS

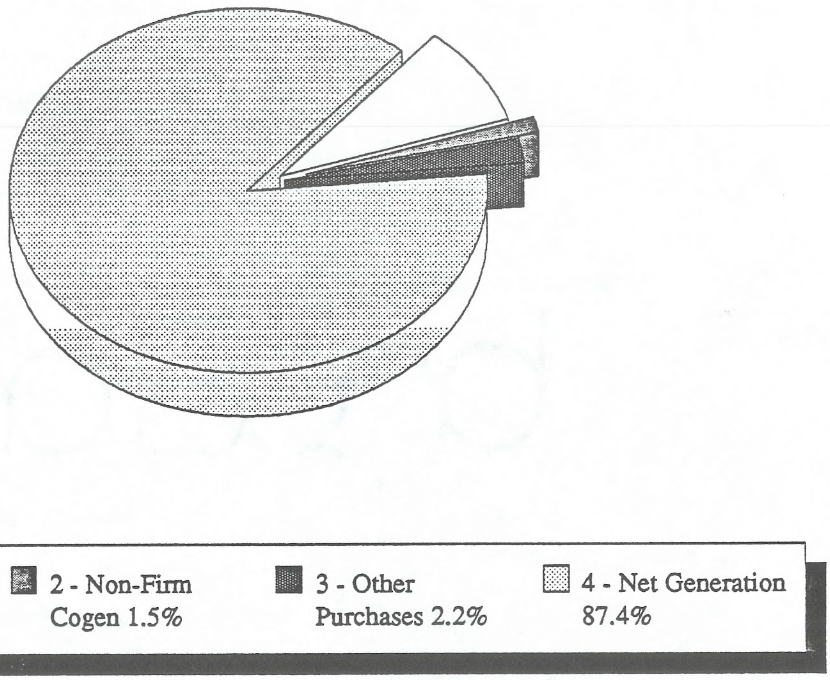
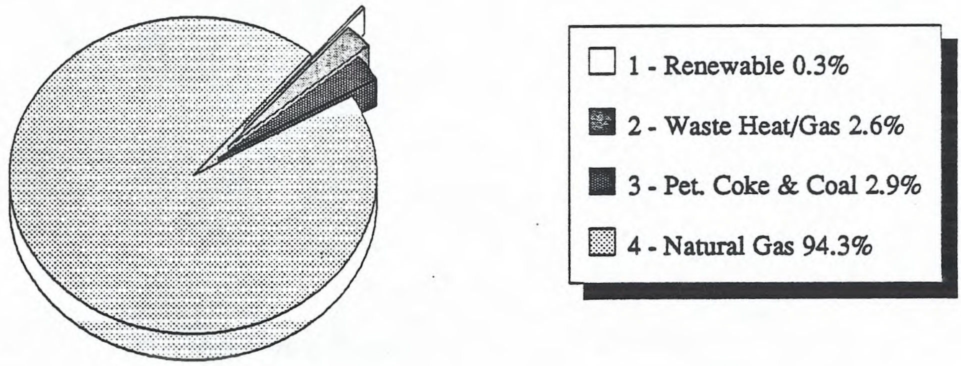


FIGURE 6.4

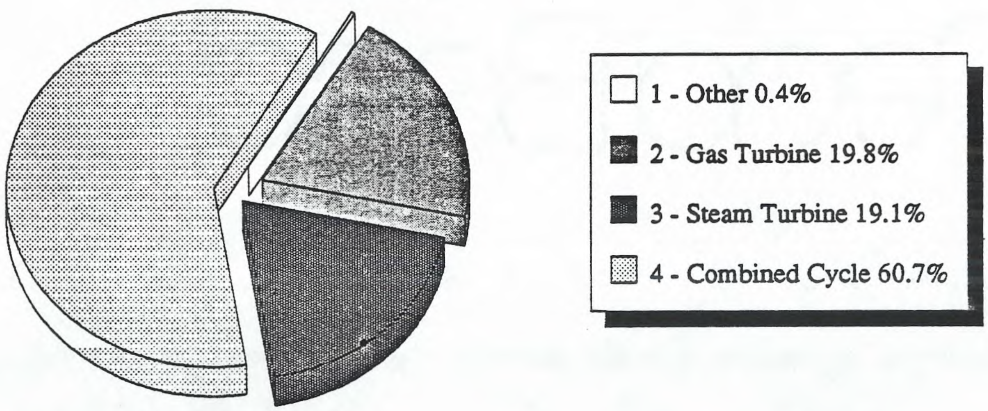
COGENERATION & SMALL POWER PRODUCTION IN TEXAS

(7,117 MW) AS OF 1990

BY FUEL TYPE



BY TECHNOLOGY



BY INDUSTRY

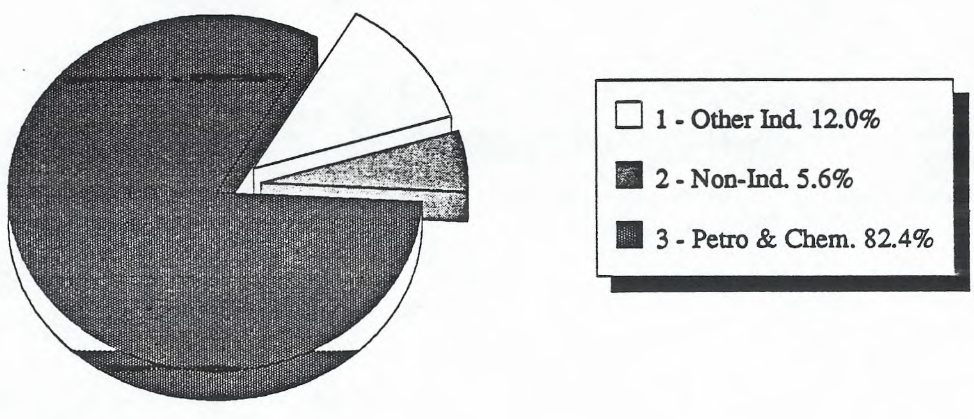
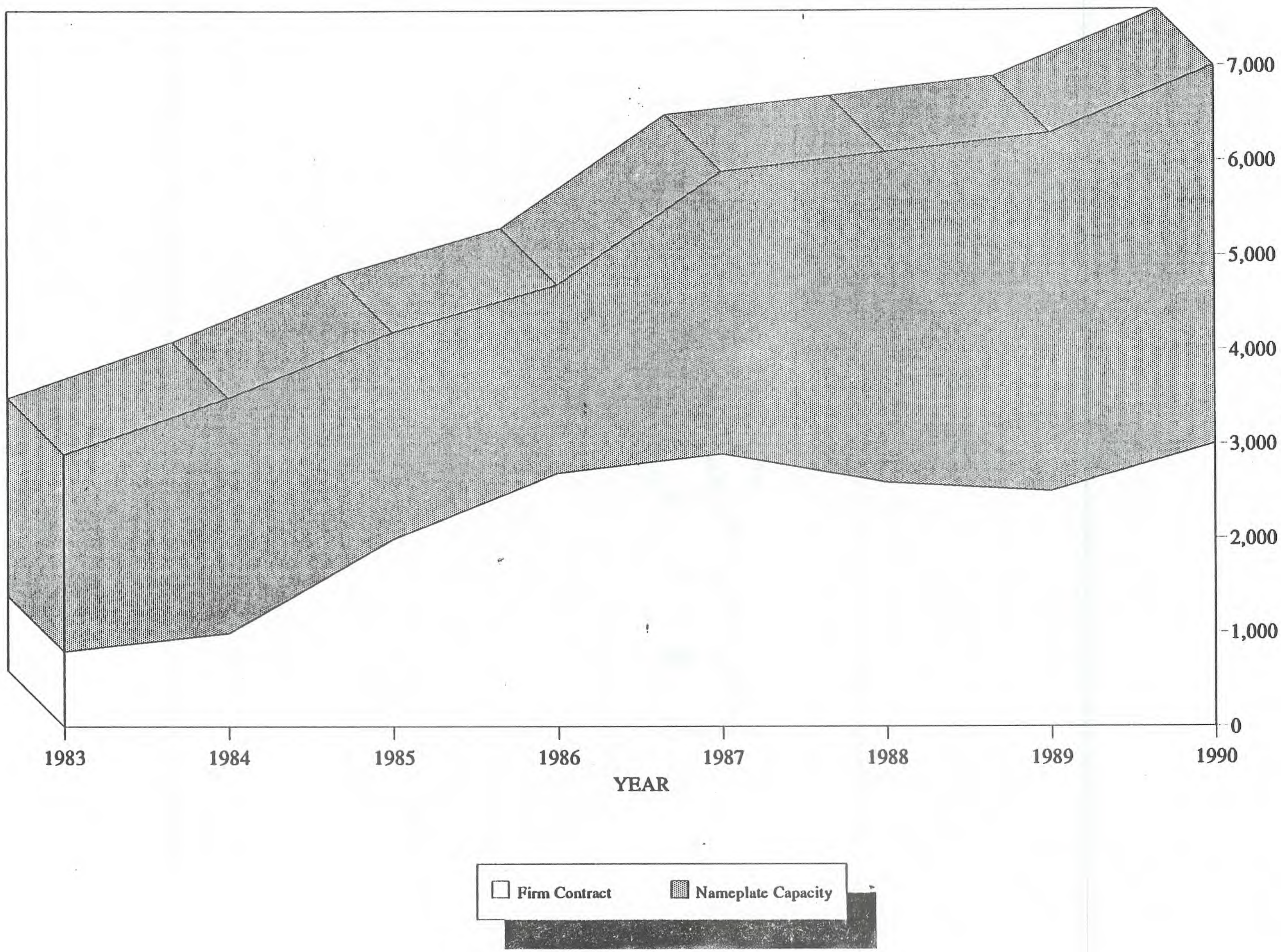


FIGURE 6.5
TRENDS IN COGENERATION



Most industrial cogeneration is concentrated in a relatively small area in and around the City of Houston, an area certificated to HL&P and TNP. Most of the cogenerated power is associated with the petrochemical industries in this area. The seven biggest projects contribute over 75 percent of the total amount cogenerated in Texas. Indeed, the largest cogenerator, Dow Chemical Company with over 1,300 MW, would be the eleventh largest generating utility in Texas if it had utility status.

With so much cogeneration concentrated in one area, Texas has had to face the problem of wheeling. Briefly, Commission rules say that utilities must wheel power from the QF to another utility if requested, provided that the wheeling utility has the transmission capacity. The methodology for calculating wheeling costs was the result of a compromise between the Commission, the QFs, and the utilities. Wheeling of electricity from QFs grew from zero in 1986 to over 1,800 MW in 1988 before declining to 1,477 MW at the end of 1989. Table 6.9 shows the amount and destination of this wheeled power.

Cogeneration Policy The current cogeneration policy in Texas, as established by the Texas Legislature and by rules of this Commission, is aimed at securing all reliable cogeneration available at prices lower than planned utility generation projects. The price for cogeneration is set by competitive negotiations between a utility and a cogenerator with an upper limit set by that utility's avoided costs. The avoided costs are established in proceedings before the Commission and are based on the cost of a generating unit that may be displaced or deferred due to firm capacity from QFs. The intent of this policy is to allow the market to determine the value and, in turn, the amount of cogeneration that will exist in Texas.

The Commission is the informal mediator of QF and utility disputes and the formal arbiter if disagreements cannot be resolved by the parties. As a result, rates are generally determined through negotiations between the utility and the cogenerator and set out in a confidential contract rather than a Commission-approved tariff. This reliance on the market has been successful, and has resulted in a better response to the dynamic cogeneration market than would a more structured and bureaucratic regulatory procedure. This picture may change over the next few years when the current excess capacity is eliminated. More and more cogenerators are interested in entering into long-term contracts. For the first time, a current avoided cost proceeding (Docket No. 9230 for

TABLE 6.9

COGENERATION UTILIZING HL&P AND TNP
WHEELING SERVICES
1989

Cogenerator	Purchasing Utility	MW
Dow Chemical	TU Electric	300
Texasgulf Inc.	TU Electric	77
Cogen Lyondell	TU Electric	400
Clear Lake Cogen	TNP	300
Cogenron	TU Electric	400
Total		1,477

HL&P's avoided costs) has not yet been settled through negotiation and is expected to go into hearing over the next few months.

Future of Cogeneration in Texas

The development of cogeneration will continue to depend on the economic health of the petrochemical industry, stable fuel costs, future electricity prices, and the need for additional generation capacity. Manufacturing industries are the main source of cogeneration among all economic sectors. Even though some potential exists for on-site electricity generation in other economic sectors, the amount is insignificant in comparison to the potential of the manufacturing sector. Among manufacturing industries, process-type industries such as paper, chemicals and allied products, petroleum, stone, clay, and glass, and primary metal are potential cogenerators. These industries, along with food and kindred products, and textile mill products, account for almost all of the potential cogeneration within the manufacturing sector.

Texas is still facing excess generating capacity. As a result, cogenerators have difficulty selling capacity to utilities on a firm basis. However, demand is increasing and utilities are not anticipating significant new capacity additions during the mid 1990s. This will result in a decline in excess capacity and a chance for a greater reliance on cogeneration during the second half of the 1990s. The information filed by the electric utilities suggests five trends in Texas cogeneration discussed below.

Declining Capacity Needs. The first trend is the decrease in utility capacity additions. Nearly all of the major utilities in Texas are predicting a much lower demand growth in the next ten years than in the last ten years. (See Volume II.) This lower projected growth rate translates into lower projected capacity requirements. These, coupled with the large amount of cogeneration in Texas, have led and will probably continue to lead to stringent contract terms and lower capacity payments to the cogenerators. Such conditions are expected to persist into the future.

Industry Maturation. A maturing cogeneration industry in Texas is evident from ownership patterns. Most cogeneration is owned by large, well-financed companies and not by small entrepreneurs. These companies are typically subsidiaries of still larger companies and the apparently simple question of "who is the owner" requires a rather lengthy answer. Other evidence of a maturing industry is the beginning of an industry-wide shake-out and consolidation and a rapid reduction in the number of applications for QF status.

As utility and cogenerator experience grows, the contract terms that have evolved are also good evidence of a maturing industry. The first Standard Terms and Conditions filed by the utilities did not address many of the areas that are covered today. Originally, little was known about how much and what kind of detail should go into these contracts. Today's more detailed contracts contain many items that both utilities and cogenerators have learned are important.

Increased Competition. Cogenerators in Texas will probably face increasing competition. This competition for dimishing capacity needs will come not only from other QFs, but also from utilities. In the past two years the Commission has allowed GSU, HL&P and CPL to create tariffs to retain industrial customers rather than allow them to leave the system and self-generate.

Regulatory Changes. Policies and rules for cogenerators are changing. In Texas, these changes have evolved through negotiation and compromise, while at the federal level some very strict mandates have been proposed. Much of the success of cogeneration in Texas is attributable to the multi-faceted character of the current policies and rules which have changed slowly and responsively. On the other hand, the FERC seems intent on radically changing their existing rules and policies in a manner that may be in conflict with those practiced in Texas. Some change will undoubtedly take place, but how this will ultimately affect cogeneration is yet to be seen.

Industrial Composition. Cogeneration projects are beginning to spread across the state. Under current conditions, most of the future cogeneration is planned for areas other than the Gulf Coast. There are two main reasons for this shift away from the Gulf Coast. First, HL&P has all the cogeneration it needs for several years and is not paying capacity payments for any additional cogeneration. Second, the transmission lines used to wheel power out of the Houston area are reaching their limits.

Cogeneration Forecast

The cogeneration forecasts made by each utility were reviewed and adjusted to fit the staff demand forecast. The overall picture that emerges from both forecasts is that nearly all firm cogeneration will continue to be purchased by HL&P and TU Electric. Commission staff's recommended cogeneration levels for the thirteen major service areas appear in Table 6.10. In addition, more detailed analyses are provided for HL&P, TU Electric, and TNP.

TABLE 6.10

RECOMMENDED COGENERATION LEVEL BY UTILITY SERVICE AREA

(MW)

YEAR	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	COA	WTU	EPE	TNP	BEPC	Texas
1989	2,009	820	11	0	0	0	0	0	0	0	0	335	0	3,169
1990	2,016	956	11	0	0	0	0	0	0	0	0	216	0	3,193
1991	1,316	956	11	0	0	0	0	0	0	0	0	242	0	2,519
1992	1,526	956	11	0	0	0	0	0	0	0	0	288	0	2,775
1993	1,316	956	11	0	0	0	0	0	0	0	0	314	0	2,591
1994	1,316	731	11	0	0	0	0	0	0	0	0	324	0	2,376
1995	1,956	375	11	0	0	0	0	0	0	0	0	275	0	2,611
1996	1,959	865	11	0	0	0	0	0	0	0	0	286	0	3,115
1997	2,209	966	11	0	0	0	0	0	0	0	0	416	0	3,596
1998	2,209	830	11	0	0	0	0	82	0	0	0	434	150	3,710
1999	2,094	1,200	11	175	0	0	0	180	0	0	0	450	200	4,304
2000	2,200	1,620	11	175	0	0	5	180	0	17	0	466	200	4,866

Note: The Texas portion of GSU is 5 MW and the Texas portion of SWEPCO is 3 MW. The Texas total includes the Texas portion for these utililities.

HL&P. When the staff demand forecasts are used, the reserve margins for HL&P still remain very high through 1995. For this reason, the staff does not differ with HL&P over their cogeneration forecast for the period 1990 through 1994. From 1995 through 2000 the staff projects a significantly higher demand. Because of this higher projected demand, it is unlikely that HL&P will drop 595 MW of cogenerated power in 1995. It is more likely that the contracts for this power will be either renewed or new cogenerators will take their place. The staff's cogeneration projections for HL&P are shown in Table 6.11. Given the staff's recommendation, about ten percent of HL&P's net system capacity in the year 2000 is anticipated to come from cogeneration.

TU Electric. The TU Electric cogeneration forecast appears very conservative in view of their capacity requirements. Apparently, the Company started with its known contracts, amounts, and expiration dates which result in a 409 MW decline in cogeneration purchases by the year 2000. TU Electric has assumed that a portion of expired cogeneration contracts will be extended. For example, the Company has indicated that by 2000 there will be 1,366 MW of expired cogeneration contracts of which 850 MW will be renewed. In addition, cogeneration, along with other options to fill the total capacity needs of the Company were listed as "unspecified resources." These "unspecified resources" could be made up of cogeneration, conservation and load management programs, new power stations, or purchased power. The staff also started with the known contracts but attempted to "sort out" how much of the unspecified resources could probably come from cogeneration. The following assumptions were made:

1. Cogeneration growth within TU Electric's service area will continue to be slow because of a lack of large steam-using industries within their area
2. Most of TU Electric's cogeneration will continue to be wheeled from the Houston area. This is very likely because of the continued lack of a market in the Houston area coupled with the concentration of potential cogeneration
3. Transmission ties will limit transfers to TU Electric from the Houston area unless planned transmission capacity additions are completed on schedule
4. Market conditions will probably result in firm contracts being renewed when they expire or replaced with the same amount of competitively priced new cogeneration

TABLE 6.11

RECOMMENDED COGENERATION LEVEL
BY UTILITY SERVICE AREA

(MW)

Year	HL&P Forecast	PUCT Forecast*
1989	820	820
1990	956	956
1991	956	956
1992	956	956
1993	956	956
1994	731	731
1995	136	375
1996	136	865
1997	136	966
1998	0	830
1999	0	1,200
2000	0	1,620

1989 is actual

* These projections are for planning purposes only and do not represent a requirement for long-term purchases from QF's. They are based on the staff's assessment that economical opportunities will exist for utilities to meet some of their expected capacity requirements with a combination of short-term and long-term cogeneration firm contracts.

Given these assumptions and TU Electric's need for additional capacity, the potential limiting factor for cogenerated power is the transmission system. The Commission staff's Bulk Power Transmission study (BPT), which was based on earlier higher load forecasts, assumed that TU Electric would be importing 1,894 MW of cogeneration by 1990 and 3,200 MW by 1995. These loads were imposed on the transmission system before any other transfers were permitted, and the transmission system still retained enough capacity to permit the transfer of an additional 2,273 MW in 1990 and 2,008 MW in 1995, assuming single contingency outage conditions. Since the maximum amount of cogeneration that TU Electric now expects to obtain is only 2,200 MW (instead of the 3,200 MW in the BPT study), there do not appear to be any significant transmission constraints. Thus, the staff recommends that its amount of cogeneration appearing in Table 6.12 be retained throughout the forecast period via contract renewal or replacement from competing cogeneration suppliers. Given the Commission staff's recommendation, about 8.5 percent of TU Electric's net system capacity in the year 2000 comes from cogeneration.

TNP. TNP had 968 MW of demand during the summer of 1989, all provided through power purchases from utility and non-utility generators. In contrast, TNP One Unit 1 went into commercial operation in 1990 and the utility is projected to have TNP One Unit 2 in operation by the end of 1991. After 1991 TNP will still rely on power purchases for the difference between its total requirements and the output of the new generating stations. TNP recently withdrew its request for certification of TNP One Units 3 and 4; thus, the Commission staff's analysis indicates that TNP will rely on more cogenerated power than its existing contracts over the forecast period. This is shown in Table 6.13. In fact, staff's recommended resource plan for TNP's service area includes significantly more cogeneration after 1996 than proposed by TNP. If the staff's forecast of demand and capacity resources materializes, 38 percent of TNP's demand in the year 2000 will be satisfied with cogeneration.

Purchased Power

As discussed in several earlier chapters, most utilities in Texas have substantial amounts of excess capacity as a result of the completion of several major projects. This excess capacity represents a low-cost resource that should be used before constructing new

TABLE 6.12

1990-2000 COGENERATION PROJECTION FOR
TU ELECTRIC

(MW)

Year	TU Electric Forecast*	PUCT Forecast**
1989	2,009	2,009
1990	2,016	2,016
1991	1,616	1,316
1992	1,316	1,526
1993	1,316	1,316
1994	1,616	1,316
1995	1,616	1,956
1996	1,539	1,959
1997	1,689	2,209
1998	1,689	2,209
1999	1,574	2,094
2000	1,600	2,200

1989 is actual

* Although most of this is cogenerated power, these figures include capacity from ALCOA and other non-utility suppliers.

** These projections are for planning purposes only and do not represent a requirement for long-term purchases from QF's. They are based on the staff's assessment that economical opportunities will exist for utilities to meet some of their expected capacity requirements with a combination of short-term and long-term cogeneration firm contracts.

TABLE 6.13

1990-2000 COGENERATION PROJECTION
FOR TNP

(MW)

Year	TNP Forecast	PUCT Forecast*
1990	216	216
1991	242	242
1992	288	288
1993	314	314
1994	324	324
1995	275	275
1996	286	286
1997	270	416
1998	142	434
1999	158	450
2000	174	466

* These projections are for planning purposes only and do not represent a requirement for long-term purchases from QF's. They are based on the staff's assessment that economical opportunities will exist for utilities to meet some of their expected capacity requirements with a combination of short-term and long-term cogeneration firm contracts.

generating units. However, there are some institutional impediments which prevent all of the state's utilities from buying and selling available capacity.

The strongest impediment to some potential bulk power transactions in Texas is the legal distinction between those utilities which are members of ERCOT (intrastate) and those which are members of other reliability councils (interstate). The intrastate utilities in the ERCOT system, with the partial exception of WTU and CPL (members of the interstate Central and Southwest holding company) are currently exempt from regulation by the FERC as a result of some special provisions of federal law. Under these legal provisions, they may not engage in bulk power transactions with non-ERCOT utilities without losing their intrastate exemption. Thus, for example, even though GSU has much excess capacity which it might be willing to sell to a capacity-short utility such as TU Electric, the transactions cannot occur at a significant level under current institutional arrangements.

Within ERCOT, the staff's BPT study has addressed the question of the potential for transactions among the utilities and the potential cost savings which might accrue as a result. However, some of the ERCOT utilities have expressed reservations about the transmission system reliability consequences of trying to exploit these potential transactions.

In developing the recommended levels of purchased power in this resource plan, the staff has relied on the results of the BPT study, evaluated in their most conservative interpretations. For example, as shown in Table 6.14, in 1990 the BPT study used as base case conditions that HL&P would be purchasing 1,241 MW of cogeneration and that TU Electric would be importing 1,894 MW of cogeneration from the HL&P service area. This total load of 3,135 MW is placed on the transmission system before the model is solved to determine the optimal amount of utility power transfers. In this resource plan, HL&P's and TU Electric's firm cogeneration purchases for 1990 are 956 MW and 2,016 MW, respectively, for a total of only 2,972 MW--in effect providing a "cushion" of more than 160 MW. The total of 2,972 MW is only 143 MW above the actual cogeneration level of 2,829 MW for the two utilities in 1989.

TABLE 6.14

TRANSMISSION CAPACITY AND PURCHASED POWER WITHIN THE ERCOT SYSTEM

	Bulk Power Transmission Study			1990 PUCT Resource Plan			
Year	Base Case Cogen. (1)	Average Purchases W/Outage (2)	Total Trans. W/Outage (3)	Cogen (4)	Other Purchases (5)	Total (6)	Resulting Unused Capacity (3)-(6)
1989	2,739	2,346	5,085	3,164	1,515	4,679	406
1990	3,135	2,273	5,408	3,188	1,029	4,217	1,191
1991	3,441	2,220	5,661	2,514	1,065	3,579	2,082
1992	3,741	2,167	5,908	2,770	1,145	3,915	1,993
1993	4,041	2,114	6,155	2,586	1,159	3,745	2,410
1994	4,241	2,061	6,302	2,371	1,004	3,375	2,927
1995	4,441	2,008	6,449	2,606	790	3,396	3,053
1996	4,441	2,008	6,449	3,110	873	3,983	2,466
1997	4,441	2,008	6,449	3,591	872	4,463	1,986
1998	4,441	2,008	6,449	3,705	877	4,582	1,867
1999	4,441	2,008	6,449	4,299	920	5,219	1,230
2000	4,441	2,008	6,449	4,858	833	5,691	758

No planned additions to the ERCOT Transmission System are Assumed beyond 1997.

Similarly, manual adjustments have been made to the intra-utility sales analysis to lower the transmission system capacity limits below the base case assumptions used in the BPT study. First, instead of using the peak capacity transfer, an average hourly transfer has been calculated which is lower than the peak. This unadjusted value would be approximately 3,200 MW. In order to provide for single contingency (outage) conditions, as discussed in Chapter 5 of the BPT study, this number is further reduced by nearly 30 percent to a maximum value of 2,273 MW and is assumed to exist for every hour of the entire year. Combining these results with the same analysis for 1995 and interpolating for intermediate years, Table 6.14 shows the transmission capacity available for intra-utility transactions within the ERCOT system. The recommended levels of purchases in the resource plan are all within these limits. Utilities needing to purchase power will likely be able to find several other utilities with excess capacity for sale. However, for each potential transaction, a specific reliability load flow analysis should be performed to insure that the integrity of the bulk power transmission system is maintained.

Recommended Additions to Capacity

The recommended capacity additions during the next ten years (1990 to 2000) reflect the demand-side adjustments to the peak demand forecasts, the peak generation requirements, and the available supply-side options. By the end of the ten years, inaccuracies inherent in the long-term peak demand forecast are estimated not to exceed 5 percent of unadjusted peak demand. This implies some 3,300 MW of variance due to forecasting error, the equivalent of five to six conventional power plants. Because of these limitations, it must be emphasized that the following recommendations should be viewed as a general planning guide rather than a detailed blueprint for capacity additions.

In the resource plan presented in this section, staff has attempted to consider all potential sources that might be available to meet the peak demand and energy requirements facing electric utilities in Texas over the next ten years. Also, the staff has relied upon the findings from several complete or near-completion studies prepared by the Commission staff. Specifically, this report relies on certain conclusions from the BPT and Optimal State Electricity Supply in Texas study (OSEST) with regard to capacity utilization of transmission lines and potential for optimal use of purchased power as a significant resource within the ERCOT system. These studies clearly demonstrate the importance of purchased power and encourage utilities to use the existing capacity within the ERCOT system more efficiently. The studies also suggest that using existing capacity more efficiently could prevent or delay the construction of new power plants. This will benefit the system as a whole.

The staff has attempted to incorporate these findings in the preparation of its resource plan. In addition, an attempt is made to determine the amount of potential deficit in the net system capacity for Texas and ERCOT if demand turns out to be higher than what the staff has projected.

New units and the costs of alternatives will be reviewed in future certification proceedings, but, at this point in time, staff recommends the completion of 3,353 MW of conventional power plants already under construction. A portion of this capacity (1,749 MW) has already been added to the state's power plant capacity this year. (See Table 6.15.) Additional capacity requirements could be met by construction of conventional power plants through the year 2000. Over the next ten years, electric utilities in Texas will retire about 1,250 MW of capacity. To meet the total net system capacity of 72,230 MW by the year 2000, 66,459 MW could be supplied by conventional power plants, 4,866 MW by cogeneration, 540 MW by inter-regional net purchased power, and 365 MW by current generating unit life extension projects through repowering. Table 6.16 lists the staff-recommended total capacity additions during the 1990 to 2000 period, with generating units grouped by fuel type. Approximately 2,392 MW of primarily coal-fueled and lignite-fueled base load and 582 MW of gas-fueled capacity scheduled in current utility filings have been deferred beyond the year 2000 in this plan. Table 6.17 lists the staff-recommended specific plant additions for 1990 to 2000.

TU Electric. The Commission staff demand projection is lower than the projection by TU Electric throughout the forecast period. Therefore, staff sees opportunities to defer some base load units and rely on more purchased power (utility and non-utility) than what is reported by the Company in their December 1989 filing. Specifically, staff is proposing deferral of Twin Oak Units 1 and 2 by one and two years, respectively (to 1996 and 1998). Forest Grove Unit 1 is recommended to be deferred one year to 1999. Finally, two 650-MW unspecified coal units planned for 1999 and 2000 are recommended for deferral by one year each. By following the Commission staff's resource plan, TU Electric can maintain an 18 percent reserve margin well above the 15 percent recommended by ERCOT.

TABLE 6.15

NEAR-TERM NEW GENERATING UNITS, 1990-1994
PUCT RESOURCE PLAN

Year	Utility	Additions [Retirements]	Construction Cost	MW	Fuel
1990	Net			1,749	
	TUEC	DeCordova CT (1-4)		260	Gas
	TUEC	Permian Basin CT (4, 5)		130	Gas
	TUEC	Comanche Peak (1)	$5,263,430,000	1,150	Uranium
	LPL	LP&L Cogen	$18,050,000	20	Gas
	SPS	Maddox #3 (487)	$1,603,000	10	Gas
	TNP	TNP One (1)	$349,931,171	146	Lignite
	GSU			-46	Gas
	Others			79	
1991	Net			129	
	TNP	TNP One (2)	$278,980,998	146	Lignite
	COA	[Seaholm (5, 6)]		-36	Gas
	Others			19	
1992	Net			10	
	SRMPA			10	Coal
1993	Net			1,200	
	TUEC	Comanche Peak (2)	$3,636,400,000	1,150	Uranium
	LPL	Repower	$30,000,000	50	Gas
1994	Net			265	
	BEPC	R W Miller (4, 5)		207	Gas
	GSU			33	Uranium
	GSU			15	Coal
	SRMPA			10	Coal
1990-1994 Total Net Addition		(MW)		3,353	

TABLE 6.16

TEXAS DETAILED CAPACITY EXPANSION

Year	Total NG/Oil	Coal	Lignite	Nuclear	Hydro	Alternate Energy Sources	Total Capacity
1990	373	43	176	1,150	7	0	1,749
1991	(36)	19	146	0	0	0	129
1992	0	10	0	0	0	0	10
1993	(194)	244	0	1,150	0	0	1,200
1994	207	25	0	33	0	0	265
1995	64	0	0	0	0	10	74
1996	(122)	20	750	0	0	0	648
1997	627	498	0	0	0	0	1,125
1998	(172)	0	1,395	0	0	0	1,223
1999	331	0	750	0	0	0	1,081
2000	341	650	0	0	0	0	991
Total	1,419	1,509	3,217	2,333	7	10	8,495

TABLE 6.17

SCHEDULED ADDITIONS AND RETIREMENTS, 1990-2000
PUCT RESOURCE PLAN

	Utility	Additions [Retirements]	Construction Cost	MW	Fuel
1990	Net			1,749	
	TUEC	DeCordova CT (1-4)		260	Gas
	TUEC	Permian Basin CT (4, 5)		130	Gas
	TUEC	Comanche Peak (1)	$5,263,430,000	1,150	Uranium
	LPL	LP&L Cogen	$18,050,000	20	Gas
	SPS	Maddox #3 (487)	$1,603,000	10	Gas
	TNP	TNP One (1)	$349,931,171	146	Lignite
	GSU			-46	Gas
	Others			79	
1991	Net			129	
	TNP	TNP One (2)	$278,980,998	146	Lignite
	COA	[Seaholm (5, 6)]		-36	Gas
	Others			19	
1992	Net			10	
	SRMPA			10	Coal
1993	Net			1,200	
	TUEC	Comanche Peak (2)	$3,636,400,000	1,150	Uranium
	LPL	Repower	$30,000,000	50	Gas
1994	Net			265	
	BEPC	R W Miller (4, 5)		207	Gas
	GSU			33	Uranium
	GSU			15	Coal
	SRMPA			10	Coal
1995	Net			74	
	COA	[Seaholm (7, 8)]		-28	Gas
	BEPC	Base 1		288	Gas
	TUEC	[Handley (1, 2)]		-125	Gas
	TUEC	[North Main]		-80	Gas
	TUEC	[Trinidad]		-70	Gas
	TUEC	[Permian Basin]		-1	Gas
	EPE	Turbine 1		70	Gas
	LPL	Waste Recovery	$50,000,000	10	Refuse
	LPL			10	Gas
1996	Net			648	
	TUEC	[Dallas (3, 9)]		-145	Gas
	TUEC	Twin Oak (1)	$1,485,387,000	750	Lignite

TABLE 6.17

SCHEDULED ADDITIONS AND RETIREMENTS, 1990-2000

PUCT RESOURCE PLAN

(Continued)

	Utility	Additions [Retirements]	Construction Cost	MW	Fuel
1996	CPL	[La Palma (7)]		-47	Gas
	EPE	Turbine 2		70	Gas
	SRMPA			20	Coal
1997	Net			1,125	
	CPS	J K Spruce (1)	$832,195,000	498	Coal
	TUEC	Unspecified	$305,467,000	375	Gas
	HL&P	N/A (GT 1, 2)	$85,582,960	160	Gas
	WTU	Repower Rio Pecos (5)	$41,824,000	92	Gas
1998	Net			1,223	
	COA	[Seaholm (9)]		-36	Gas
	CPL	Repower Laredo	$51,698,000	90	Gas
	TUEC	Twin Oak (2)	$793,420,000	750	Lignite
	TUEC	[Mountain Creek (2, 3)]		-103	Gas
	TUEC	[Morgan Creek (2, 3)]		-66	Gas
	HL&P	Malakoff 1	$1,843,309,000	645	Lignite
	WTU	[Abilene]		-18	Gas
	WTU	[Concho 3]		-15	Gas
	WTU	[Lake Pauline 1]		-19	Gas
	WTU			-5	Gas
1999	Net			1,081	
	HL&P	N/A (Conversion)	$227,104	160	Gas
	TUEC	Forest Grove 1	$1,417,056,000	750	Lignite
	GSU			50	Gas
	WTU	Repower Rio Pecos (6)	$29,789,000	41	Gas
	EPE	Combined 1		80	Gas
2000	Net			991	
	COA	[Holly (1)]		-97	Gas
	TUEC	[Eagle Mountain]		-115	Gas
	TUEC	[Parkdale (1)]		-87	Gas
	TUEC	[River Crest]		-110	Gas
	TUEC	Unspecified		244	Gas
	TUEC	Unspecified		650	Coal
	CPS	GT 00 (1)		70	Gas
	SWEPCO	Repower Wilkes (2, 3)	$81,170,000	174	Gas
	LCRA	N/A		127	Gas
	WTU	WTU CT	$64,584,000	135	Gas
1990-2000 Total Net Addition				8,495	MW

HL&P. Commission staff recommends that HL&P defer construction of the Malakoff Units 1 and 2. These lignite units, with expected capacity of 645 MW each, were scheduled for serving system summer peak in 1997 and 1999. Deferral of Malakoff Unit 1 to 1998 and Unit 2 to beyond the year 2000 leaves HL&P with adequate system capacity to maintain at least an 18 percent reserve margin. In addition, Commission staff recommends deferral of two 80-MW gas units from 1995 to 1997 and deferral of two additional 80-MW gas units from 1996 to 1999. As discussed previously in the Cogeneration Forecast, HL&P could extend existing contracts or negotiate new contracts with cogeneration power suppliers.

CPL. Commission staff projects slower growth in demand over the forecast period for the CPL service area. This suggests the possibility of deferring the repowering of the J. L. Bates 1 natural gas unit from the planned 1999 service date to beyond the year 2000.

CPS. CPS may have an opportunity to defer construction of the J. K. Spruce 1 coal unit until 1997 from the current target date of 1992. The 498-MW generating unit need not be added to the 502 MW of excess capacity projected for 1992. Deferral would bring the reserve margin to 16 percent in 1996, still above the targeted 15 percent. Also, J. K. Spruce 2 can be deferred beyond the forecast horizon. CPS is proposing two 70-MW gas units for 1998 and an additional three 70-MW gas units for 1999. Commission staff recommends deferral of these units to beyond the year 2000 with the exception of one 70-MW gas unit recommended for completion in the year 2000.

LCRA. Commission staff projects higher growth in demand over the forecast period for the LCRA service area. However, staff believes that the other resources available to LCRA may result in the deferral of two 127-MW gas units planned for completion in 1999 and 2000. Staff recommends that the first 127-MW unit be deferred one year to 2000 and that the second unit be deferred to beyond the year 2000. Staff suggests that LCRA might benefit from reliance on cogenerated power in the late 1990s.

COA. Commission staff's demand projections are lower than the city's over the forecast period. As a result, COA may consider deferring plans for a 400-MW coal unit addition in 1999. This would still leave COA with over 30 percent reserve margin in that year. However, transmission problems in the COA system may require the completion of this unit.

EPE. Due to the higher demand projections prepared by Commission staff for EPE in the mid 1990s, EPE may need to bring its 70-MW gas unit into operation a year sooner than the proposed 1996 target date. In addition, staff recommends that the 70-MW and 80-MW gas units proposed for 1998 and 2000 be accelerated to 1996 and 1999, respectively. EPE also has the option of considering lower reserve margins for planning purposes. While EPE's current planning reserve margins are significantly higher than all other major utilities in Texas, Commission staff has not altered them at this time.

BEPC. Brazos has planned to participate in the operation of a lignite power plant in 1998. Given the availability of cogenerated power, staff is recommending deferral of that unit to beyond the year 2000.

Except for EPE, the other three major non-ERCOT utilities continue to experience excess capacity throughout the forecast period. SPS has planned to convert a 244-MW gas unit to coal in 1993. GSU does not expect significant changes in capacity over the forecast period. Finally, SWEPCO is planning to repower the two 87-MW Wilkes units.

A summary of the annual power plant additions for thirteen major electric utilities is presented in Table 6.18. Resource plans for individual utilities based on the Commission staff's peak demand projections are provided in Appendix A of this Volume.

Tables 6.19, 6.21, and 6.23 summarize the demand and capacity forecasts for Texas during the 1989-2000 period. In addition, results for ERCOT are summarized in Tables 6.20, 6.22, and 6.24. As verified in Tables 6.23 and 6.24, the recommended resource plans result in reserve margins significantly in excess of the target for Texas, as well as for ERCOT, up to 1996; in 1997, the declining reserve margins approach (but still exceed) the specified targets.

High-Demand Scenario

The base case peak demand projection by the Commission staff prior to demand adjustments is more than 1 percent below the utilities' peak demand projection for the year 2000. If demand adjustments are taken into consideration, staff's peak demand projections are slightly higher than the projections by the utilities for that year. Staff believes that its resource plan, which relies on smaller utility-owned additions to capacity, is flexible enough to handle either its recommended base case demand forecasts or the utilities' slightly lower demand projections.

TABLE 6.18

STAFF RECOMMENDED NET POWER PLANT ADDITIONS BY SERVICE AREA (MW)

Year	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	COA	WTU	EPE	TNP	BEPC	Others	Texas
1990	1,540	0	(46)	0	0	10	0	0	0	0	(1)	146	0	100	1,749
1991	0	0	0	0	0	0	0	0	(36)	0	0	146	0	19	129
1992	0	0	0	0	0	0	0	0	0	0	0	0	0	10	10
1993	1,150	0	0	0	0	0	0	0	0	0	0	0	0	50	1,200
1994	0	0	48	0	0	0	0	0	0	0	0	0	207	10	265
1995	(276)	0	0	0	0	0	0	0	(28)	0	70	0	288	20	74
1996	605	0	0	(47)	0	0	0	0	0	0	70	0	0	20	648
1997	375	160	0	0	498	0	0	0	0	92	0	0	0	0	1,125
1998	581	645	0	90	0	0	0	0	(36)	(57)	0	0	0	0	1,223
1999	750	160	50	0	0	0	0	0	0	41	80	0	0	0	1,081
2000	582	0	0	0	70	0	174	127	(97)	135	0	0	0	0	991

Due to uncertainties associated with peak demand projections, staff has prepared a scenario in which peak demand projections prior to demand adjustments is 5 percent higher than what is used in the staff's base case resource plan. This results in 3.6 percent rather than 3.1 percent annual growth in peak demand prior to demand adjustments for Texas in 2000. If demand adjustments are taken into account, we will have 3 percent rather than 2.5 percent annual growth in peak demand from 1990 to 2000. Under this scenario, all new additions and retirements proposed by the utilities in their 1989 December filing are included. In addition, staff's projected power purchases (utility and non-utility) within the state is also considered. These projections are somewhat higher than what is proposed by electric utilities in Texas. Finally, the same level of demand-side adjustments as in the base case is used to derive the high-demand scenario resource plan.

Tables 6.25, 6.27, and 6.29 summarize the demand and net system capacity forecast for Texas during the next ten years under the *high-demand* scenario. Similar results for the ERCOT system are provided in Tables 6.26, 6.28, and 6.30. As is clear from these tables, Texas as well as ERCOT may face capacity deficits in 1998 under the high demand scenario. A decifit could occur as early as 1995 if the high demand scenario included the utilities', not the staff's, projected purchases from utility and non-utility sources. In fact, staff's high demand scenario resource plan for non-ERCOT shows a capacity shortage for these utilities beyond 1997. However, these utilities are well interconnected to other utilities in their respective reliability councils and may obtain power from these sources. ERCOT has limited options to obtain purchased power from non-ERCOT utilities and must rely on other resources.

Staff believes that there are several resources that could be utilized to overcome the resulting capacity deficit under the high demand scenario. Construction of new units is obviously one solution. Staff also believes that additional effective demand-side management programs could help reduce the growth in peak demand. Given the availability of transmission lines and improvements made to the transmission system, cogeneration may be utilized more extensively to help ease the capacity deficiency. Finally, generation unit life extension projects may also be used to provide additional power to overcome the resulting capacity deficit.

TABLE 6.19

PEAK DEMAND AND DEMAND ADJUSTMENTS
TEXAS
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments.
1989	46,387					46,387
1990	49,202	95	1,559	98	1,752	47,451
1991	50,293	138	1,388	234	1,759	48,534
1992	51,453	182	1,431	371	1,984	49,469
1993	52,915	256	1,559	496	2,311	50,604
1994	54,301	331	1,602	632	2,565	51,736
1995	56,009	388	1,659	801	2,848	53,162
1996	57,744	445	1,784	961	3,189	54,555
1997	59,511	492	1,863	1,123	3,478	56,034
1998	61,253	542	1,941	1,290	3,773	57,480
1999	63,158	542	2,017	1,456	4,014	59,144
2000	65,130	542	2,087	1,619	4,248	60,883

Note: Texas figures are adjusted downward by 1 percent to reflect load diversity among Texas utilities

TABLE 6.20

PEAK DEMAND AND DEMAND ADJUSTMENTS
ERCOT
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments.
1989	38,960					38,960
1990	41,547	99	1,423	98	1,620	39,928
1991	42,490	139	1,248	233	1,620	40,870
1992	43,572	180	1,292	370	1,842	41,731
1993	44,873	248	1,419	495	2,162	42,711
1994	46,082	317	1,463	631	2,410	43,671
1995	47,608	369	1,519	799	2,688	44,920
1996	49,169	422	1,645	959	3,025	46,144
1997	50,770	466	1,724	1,120	3,310	47,459
1998	52,339	511	1,802	1,287	3,600	48,739
1999	54,058	511	1,878	1,453	3,841	50,217
2000	55,852	511	1,948	1,616	4,074	51,778

Note: ERCOT figures are adjusted downward by 1 percent to reflect load diversity among Texas utilities

TABLE 6.21

INSTALLED CAPACITY
TEXAS
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Alternative Energy Sources (Hydro)	Allocation Factor	Total Installed Generating Capacity
1989	41,724	10,631	8,986	3,755	489	89.14%	58,466
1990	42,097	10,674	9,161	4,905	496	89.45%	60,232
1991	42,061	10,693	9,307	4,905	496	89.56%	60,422
1992	42,061	10,703	9,307	4,905	496	89.51%	60,394
1993	41,867	10,947	9,307	6,055	496	89.72%	61,612
1994	42,074	10,972	9,307	6,088	496	89.74%	61,867
1995	42,138	10,972	9,307	6,088	506	89.65%	61,867
1996	42,016	10,992	10,057	6,088	506	89.76%	62,525
1997	42,643	11,490	10,057	6,088	506	89.82%	63,576
1998	42,471	11,490	11,452	6,088	506	90.08%	64,867
1999	42,802	11,490	12,202	6,088	506	90.09%	65,849
2000	43,143	12,140	12,202	6,088	506	90.21%	66,824

TABLE 6.22

INSTALLED CAPACITY
ERCOT
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Alternative Energy Sources (Hydro)	Allocation Factor	Total Installed Generating Capacity
1989	31,826	5,817	8,081	2,500	448	50.00%	48,672
1990	32,216	5,817	8,227	3,650	448	100.00%	50,358
1991	32,180	5,817	8,372	3,650	448	100.00%	50,467
1992	32,180	5,817	8,372	3,650	448	100.00%	50,467
1993	32,180	5,817	8,372	4,800	448	100.00%	51,617
1994	32,387	5,817	8,372	4,800	448	100.00%	51,824
1995	32,371	5,817	8,372	4,800	448	100.00%	51,808
1996	32,179	5,817	9,122	4,800	448	100.00%	52,366
1997	32,806	6,315	9,122	4,800	448	100.00%	53,491
1998	32,634	6,315	10,517	4,800	448	100.00%	54,714
1999	32,835	6,315	11,267	4,800	448	100.00%	55,665
2000	33,002	6,965	11,267	4,800	448	100.00%	56,482

TABLE 6.23

NET SYSTEM CAPACITY AND RESERVE MARGINS
TEXAS
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm -Off System Sales	Net System Capacity	Reserve Margin (%)	Target Margin (%)	Excess Capacity
1989	2,339	3,169	1,663	62,310	34.33%	17.81%	7,661
1990	1,661	3,193	1,181	63,905	34.68%	18.48%	7,686
1991	1,660	2,519	1,220	63,381	30.59%	17.93%	6,147
1992	1,759	2,775	1,313	63,614	28.60%	17.88%	5,302
1993	1,767	2,591	1,329	64,641	27.74%	17.87%	4,996
1994	1,632	2,376	1,184	64,691	25.04%	17.12%	4,098
1995	1,451	2,611	988	64,940	22.16%	17.08%	2,701
1996	1,507	3,115	1,076	66,070	21.11%	17.05%	2,214
1997	1,530	3,596	1,054	67,647	20.73%	17.01%	2,083
1998	1,531	3,710	1,085	69,023	20.08%	16.98%	1,780
1999	1,605	4,304	1,096	70,662	19.47%	16.94%	1,500
2000	1,562	4,866	1,022	72,230	18.64%	16.92%	1,049

TABLE 6.24

NET SYSTEM CAPACITY AND RESERVE MARGINS
ERCOT
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm -Off System Sales	Net System Capacity	Reserve Margin (%)	Target Margin (%)	Excess Capacity
1989	1,515	3,164	1,515	51,836	33.05%	17.94%	5,887
1990	1,029	3,188	1,029	53,546	34.11%	18.73%	6,138
1991	1,065	2,514	1,065	52,981	29.63%	18.09%	4,717
1992	1,145	2,770	1,145	53,237	27.57%	18.05%	3,974
1993	1,159	2,586	1,159	54,203	26.91%	18.04%	3,789
1994	1,004	2,371	1,004	54,195	24.10%	17.15%	3,034
1995	790	2,606	790	54,414	21.14%	17.12%	1,805
1996	873	3,110	873	55,476	20.22%	17.09%	1,448
1997	872	3,591	872	57,082	20.28%	17.06%	1,527
1998	877	3,705	877	58,419	19.86%	17.03%	1,379
1999	920	4,299	920	59,964	19.41%	17.00%	1,212
2000	833	4,858	833	61,340	18.47%	16.97%	776

TABLE 6.25

PEAK DEMAND AND DEMAND ADJUSTMENTS
HIGH-DEMAND SCENARIO - TEXAS
(MW)

Year	Peak Demand Before Adjustments	Exogenous Factors	Demand Adjustments Active DSM	Passive DSM	Total	Peak Demand After Adjustments.
1989	46,387					46,387
1990	51,662	95	1,559	108	1,762	49,900
1991	52,808	138	1,388	242	1,767	51,041
1992	54,026	182	1,431	371	1,984	52,041
1993	55,561	256	1,559	489	2,304	53,257
1994	57,016	331	1,602	618	2,551	54,465
1995	58,810	388	1,659	772	2,819	55,991
1996	60,631	445	1,784	915	3,144	57,487
1997	62,487	492	1,863	1,062	3,417	59,070
1998	64,315	542	1,941	1,212	3,695	60,621
1999	66,316	542	2,017	1,363	3,922	62,394
2000	68,387	542	2,087	1,514	4,143	64,244

Note: Texas figures are adjusted downward by 1 percent to reflect load diversity among Texas utilities

TABLE 6.26

PEAK DEMAND AND DEMAND ADJUSTMENTS
HIGH-DEMAND SCENARIO - ERCOT
(MW)

Year	Peak Demand Before Adjustments	Exogenous Factors	Demand Adjustments Active DSM	Passive DSM	Total	Peak Demand After Adjustments.
1989	38,960					38,960
1990	43,625	99	1,423	108	1,630	41,994
1991	44,614	139	1,248	241	1,628	42,986
1992	45,751	180	1,292	370	1,842	43,909
1993	47,117	248	1,419	488	2,155	44,962
1994	48,386	317	1,463	617	2,396	45,989
1995	49,988	369	1,519	771	2,659	47,329
1996	51,628	422	1,645	913	2,979	48,648
1997	53,308	466	1,724	1,060	3,250	50,058
1998	54,956	511	1,802	1,209	3,522	51,435
1999	56,761	511	1,878	1,361	3,749	53,012
2000	58,644	511	1,948	1,511	3,969	54,675

Note: ERCOT figures are adjusted downward by 1 percent to reflect load diversity among Texas utilities

TABLE 6.27

INSTALLED CAPACITY
HIGH-DEMAND SCENARIO - TEXAS
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Alternative Energy Sources (Hydro)	Allocation Factor	Total Installed Generating Capacity
1989	41,724	10,631	8,986	3,755	489	89.14%	58,466
1990	42,097	10,674	9,161	4,905	496	89.45%	60,232
1991	42,061	10,693	9,307	4,905	496	89.56%	60,422
1992	42,061	11,201	9,307	4,905	496	88.85%	60,394
1993	41,867	11,445	9,307	6,055	496	89.07%	61,612
1994	42,074	11,470	9,307	6,088	496	89.10%	61,867
1995	42,228	11,470	10,057	6,088	506	88.02%	61,922
1996	42,266	11,490	10,807	6,088	506	87.95%	62,580
1997	42,733	11,490	11,452	6,088	506	88.05%	63,631
1998	42,771	11,490	12,402	6,088	506	88.55%	64,867
1999	43,374	12,540	13,047	6,088	506	87.24%	65,912
2000	43,725	13,688	13,047	6,088	506	86.72%	66,824

TABLE 6.28

INSTALLED CAPACITY
HIGH-DEMAND SCENARIO - ERCOT
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Alternative Energy Sources (Hydro)	Allocation Factor	Total Installed Generating Capacity
1989	31,826	5,817	8,081	2,500	448	50.00%	48,672
1990	32,216	5,817	8,227	3,650	448	100.00%	50,358
1991	32,180	5,817	8,372	3,650	448	100.00%	50,467
1992	32,180	6,315	8,372	3,650	448	99.02%	50,467
1993	32,180	6,315	8,372	4,800	448	99.04%	51,617
1994	32,387	6,315	8,372	4,800	448	99.05%	51,824
1995	32,531	6,315	9,122	4,800	448	97.35%	51,808
1996	32,499	6,315	9,872	4,800	448	97.09%	52,366
1997	32,966	6,315	10,517	4,800	448	97.18%	53,491
1998	32,934	6,315	11,467	4,800	448	97.77%	54,714
1999	33,487	7,365	12,112	4,800	448	95.62%	55,665
2000	33,584	8,513	12,112	4,800	448	95.00%	56,482

TABLE 6.29

NET SYSTEM CAPACITY AND RESERVE MARGINS
HIGH-DEMAND SCENARIO - TEXAS
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm -Off System Sales	Net System Capacity	Reserve Margin (%)	Target Margin (%)	Excess Capacity
1989	2,339	3,169	1,663	62,310	34.33%	17.81%	7,661
1990	1,661	3,193	1,181	63,905	28.07%	18.48%	4,784
1991	1,660	2,519	1,220	63,381	24.18%	17.93%	3,190
1992	1,759	2,775	1,313	63,614	22.24%	17.88%	2,270
1993	1,767	2,591	1,329	64,641	21.38%	17.87%	1,870
1994	1,632	2,376	1,184	64,691	18.77%	17.12%	903
1995	1,414	2,611	988	64,958	16.02%	17.07%	-592
1996	1,498	3,115	1,076	66,116	15.01%	17.05%	-1,171
1997	1,506	3,596	1,054	67,679	14.57%	17.01%	-1,436
1998	1,531	3,710	1,085	69,023	13.86%	16.98%	-1,892
1999	1,589	4,304	1,096	70,709	13.33%	16.94%	-2,251
2000	1,562	4,866	1,022	72,230	12.43%	16.91%	-2,879

TABLE 6.30

NET SYSTEM CAPACITY AND RESERVE MARGINS
HIGH-DEMAND SCENARIO - ERCOT
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm -Off System Sales	Net System Capacity	Reserve Margin (%)	Target Margin (%)	Excess Capacity
1989	1,515	3,164	1,515	51,836	33.05%	17.94%	5,887
1990	1,029	3,188	1,029	53,546	27.51%	18.74%	3,683
1991	1,065	2,514	1,065	52,981	23.25%	18.09%	2,217
1992	1,145	2,770	1,145	53,237	21.24%	18.05%	1,402
1993	1,159	2,586	1,159	54,203	20.55%	18.04%	1,133
1994	1,004	2,371	1,004	54,195	17.84%	17.15%	319
1995	790	2,606	790	54,414	14.97%	17.12%	-1,016
1996	873	3,110	873	55,476	14.04%	17.08%	-1,483
1997	872	3,591	872	57,082	14.03%	17.06%	-1,514
1998	877	3,705	877	58,419	13.58%	17.03%	-1,773
1999	920	4,299	920	59,964	13.11%	16.99%	-2,056
2000	833	4,858	833	61,340	12.19%	16.97%	-2,611

CHAPTER SEVEN

CONCLUSIONS AND RECOMMENDATIONS

Conclusions

Article III, Section 16(b) of the Texas Public Utility Regulatory Act requires the Public Utility Commission of Texas to prepare a biennial long-term statewide electrical energy forecast. This forecast report was prepared by the staff of the Commission's Electric Division and consists of three volumes:

1. Volume I contains the Commission staff's independent long-term peak demand forecast and capacity resource plan for Texas
2. Volume II is a summary of the generating utilities' December 31, 1989 load and capacity resource forecast filings (as amended)
3. Volume III provides supporting documentation on the Commission staff's forecasting models

The Commission staff draws the following conclusions based on the analysis presented herein:

1. An average annual growth rate of 2.50 percent in adjusted electric peak demand is expected over the next ten years (1990 to 2000).[1] This staff projection is a slightly greater than the utilities' anticipated 2.46 percent
2. Commission staff places more reliance in its resource plan on bulk power transactions among utilities and on purchases of cogenerated power from qualifying facilities than do the utilities

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1 The "10-year" forecast and resource plan discussed throughout this report actually covers the period 1990 to 2000 (or 11 years, inclusive). The eleventh year is included to facilitate comparisons with other reports and projections, many of which refer to the year 2000. The "adjusted" forecast refers to the forecast after post-modeling adjustments for the effects of exogenous factors and demand-side management.

3. The net effect of the previous two conclusions is that some planned power plant additions may be economically deferred beyond the utilities' expected on-line dates without compromising reliability. In total, the Commission staff recommends deferral of 2,974 MW of capacity beyond the year 2000 as compared with the utilities' proposed resource plans
4. Texas has sufficient reliable generating capacity to meet its growing electrical energy needs over the next ten years over a range of assumptions
5. Average electricity prices in Texas are expected to remain lower than national averages. Electricity prices in Texas are expected to increase at a pace below the rate of general inflation. As a result, the real price of electricity will decline during the forecast period

Although the outlook for the state's electric power industry is generally favorable, a number of issues deserve prompt attention from the state's utilities and the Commission:

1. The potential transmission bottlenecks which exist between Houston and Dallas and to some extent within the City of Austin should be alleviated
2. Near-term rate increases from power plant additions should be moderated to prevent widespread self-generation or bypass, to minimize the burden placed on consumers, and to encourage economic development in Texas
3. More attention should be given to energy efficiency and demand-side management programs to encourage the efficient use of electricity and to prevent unnecessary capacity expansion

The Commission's Electric Division staff concludes that Texas is, and will remain, a low-cost and reliable supplier of electrical energy services. The thirteen electric utilities examined in depth in this report represent both investor-owned and public suppliers of electricity. These utilities' approaches to forecasting and resource planning differ, but the differences are not dramatic. In fact, due to the staff's persistence in critiquing the utilities' forecasting models, the gap between utility and the staff forecasts has narrowed over the past few years. The Commission staff has prepared an independent assessment of the future demands for electrical services and examined how they may be met. There is more agreement than discord among all parties involved in these forecasting activities. The Commission staff is dedicated to enhancing its analyses and modeling techniques to ensure that load forecasting and resource planning activities in Texas will contribute to a reliable and low-cost electrical energy system for years to come.

Recommendation

The primary recommendation offered by Commission staff is the adoption of this report.

Staff Recommendation:

> **Adopt this three-volume report as the 1990 long-term statewide electrical energy forecast required by the Texas Public Utility Regulatory Act, Article III, Section 16(b).**

Many forecasting and resource planning issues are discussed in this volume. Several minor issues will be dealt with by the Commission staff as part of its routine duties. Other issues affect Commission policy and require a more formal consideration. The next section focuses on the analyses which should be undertaken by the state's major utilities to improve electrical energy forecasting and resource planning. The Commission staff seeks the approval of the Commission in insuring that these studies will be completed. The final portion of this chapter lists the studies which the Commission staff (with assistance from other organizations) will investigate during the next two years.

Studies Which Should Be Undertaken By Utilities

Chapter 4 in this Volume discusses strategic rate design and environmental issues. Commission staff believes that it is incumbent on the state's major utilities to undertake studies which will further define the role of strategic rate design in resource planning and estimate the likely impact of the Clean Air Act amendments.

Strategic Rate Design. There is an emerging recognition that rate design can be used as a powerful resource planning tool. The structure, levels of charges, and terms and conditions of various rate offerings can have a significant impact on the quantity and timing of electricity consumption. Rate design can thus be considered a resource planning tool because it affects consumption patterns which, in turn, influence generation requirements. The Commission should require that the 13 major generating electric utilities identified in this report assess the potential for strategic rate design as a resource in their service areas. Each utility should indicate which current tariffs affect resource planning, indicate what more can be done, and estimate the peak demand and energy impacts of all reasonable pricing options available to them. The assessment should appear in the December 1991 load and capacity resource forecast filing.

Clean Air Act. The 1990 amendments to the Clean Air Act may have far-reaching consequences for the state's generating utilities. The Commission should require that the 13 major generating electric utilities assess the operational and financial impacts of the 1990 amendments to the Clean Air Act on their systems. In particular, each utility should explicitly state the current and planned generating units which will be affected, estimate the total dollar impact, and estimate the likely rate impact in future years. The assessment should appear in the December 1991 load and capacity resource forecast filing.

The analysis presented in Chapter 6 highlights the need for further study of the planning criteria used by the state's major utilities. The two major issues identified were the potential for increased electrical energy transactions and target reserve margins.

Increased Electrical Energy Transactions. Two Commission staff studies have indicated that there is the potential for economic gains resulting from increased electrical energy transactions among utilities and with qualifying facilities. While the staff analyses have generally been praised, little in the way of substantive changes have resulted. The Commission should require that the nine major generating electric utilities in Electric Reliability Council of Texas (TU Electric, HL&P, CPL, CPS, LCRA, COA, WTU, TNP, and BEPC) assess the technical feasibility, institutional constraints, costs, and benefits of increased electrical energy transactions among interconnected utilities and with qualifying facilities. This assessment may take the form of a critique of the Commission staff's recent transmission studies along with a statement of progress to date and a plan of action to overcome remaining technical and institutional constraints. The assessment should appear in the December 1991 load and capacity resource forecast filing.

Target Reserve Margins. The target reserve margin is one of the factors which affects the need for additional capacity. Target reserve margins may vary from year to year based on the generation mix, planned capacity additions, and other system characteristics. As a result, utilities in Texas do not have the same target reserve margins, although all ERCOT utilities must meet the required 15 percent minimum. For example, the target reserve margins for HL&P and TU Electric take into account the level of dependence on non-utility generation and the addition of large nuclear units to arrive at an 18 or 20 percent minimum. Statewide, the addition of 1 percent to the target reserve margin (for example, from 15 percent to 16 percent) results in the addition of one 600-MW unit to the state's generation capability (about 3/4 of a billion dollars of investment). Given the high cost of capacity reserves and the importance of a reliable system, Commission staff recommends that the Commission require that the 13 major generating electric utilities assess the appropriate level of optimal reserve margins for their systems. This assessment should explicitly examine the required level of reliability and the cost of that level of reliability. Further, each utility should indicate the potential for the degradation of reliability due to increased use of power from qualifying facilities. Finally, each utility should specify how it can lower reserves without compromising reliability. The assessment should appear in the December 1991 load and capacity resource forecast filing.

Finally, the Commission should encourage ERCOT to perform studies as outlined in the previous two paragraphs.

Commission Staff Studies

Past Studies In the **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas 1988**, the staff identified seven topics for further analysis. These were: 1) the Optimal State Electricity Supply System in Texas (OSEST), 2) the End-Use Modeling Project, 3) construction monitoring, 4) incentive regulation, 5) cogeneration analysis, 6) rate design, and 7) the forecast filing format. During the past two years each topic has received varying degrees of Commission staff time and resources.

State funding from the Oil Overcharge Settlement Fund was provided through the Governor's Energy Office for the End-Use Modeling Project and the OSEST Project. The industrial modeling phase of the End-Use Modeling Project was reported in several interim reports and the final project report. The residential end-use model was used to estimate the impact of federal appliance efficiency standards reported in Chapter 5. The Hourly Electric Load Model (HELM) was used to produce the peak demand forecasts reported in Chapter 3.

Concerning the other topics, Commission staff has accomplished the following:

1. Monitoring of power plant construction and transmission line construction is reported monthly in the Commission staff's Construction Progress Report.
2. Commission staff sent questionnaires to utilities regarding regulatory incentives for efficient power plant operation and reported the survey results. An incentive regulation proposal for nuclear-fueled generation efficiency is pending before the Commission.
3. The contribution of qualifying facilities to the electrical energy production in Texas is monitored and a report is updated annually. In addition, Commission staff has prepared an Avoided Cost Filing Format which forms the basis for the current proceedings. Finally, a study of standby rates is under preparation.
4. Commission staff has continued its study of strategic rate design and electrical resource planning. Time-of-use, interruptible, and standby rates are discussed in Chapters 4 and 5 of this volume. The Commission's Real-Time Pricing Task Force meets approximately every six months.
5. The Load and Capacity Resource Forecast Filing Format was revised and formed the basis of the December 1989 filings. Improvements are an ongoing part of the Commission staff's work.
6. Commission staff has refined its Econometric Electricity Demand Forecasting System during the past two years. Notably, a personal computer version of the models and databases has been created.

Proposed Studies In an effort to enhance the activities of the staff, the Commission has approved funding for the Center for Energy Studies and has applied to the Governor's Energy Office for support from the Oil Overcharge Settlement Fund. In addition, Commission staff may propose that regulatory incentives for the conservation of resources be considered by the Commission.

Center for Energy Studies (CES) Research. The Commission has approved funding for the Center for Energy Studies of The University of Texas at Austin to investigate the following topics:

1. **Utility Information System (UIS).** This project will allow the Commission staff to rely on CES to better monitor and evaluate the work performed by the outside consultant to develop and implement UIS at the Commission.

2. **Technical and Analytical Support.** This project will provide the Electric Division staff with improved capability in subject areas to be determined.
3. **Conservation Program Analysis.** This project will improve the Electric Division staff's capability to evaluate the impacts and economics of conservation and load management programs through the implementation of a residential building simulation model.
4. **Production Cost Modeling.** This project will provide the Electric Division staff with improved capability to analyze a variety of issues related to utility system operations including fuel costs, generation mix, and marginal costs. Existing public domain and inexpensive production costing models will be reviewed and tested by CES. Following this evaluation, CES will make recommendations to the Commission staff concerning acquisition and implementation of a production costing model that meets the Commission staff's unique needs.
5. **Resource Planning Models.** This project will provide the Electric Division staff with improved capability to address a variety of system planning issues, including optimal capacity additions and the impact on utility systems of conservation and cogeneration. Models will be implemented with "base case" inputs for four utilities in the first year of this project.
6. **Load Flow Software.** This project will provide the Electric Division staff with improved capability to address a variety of transmission-related issues, including the need for proposed lines and the calculation of wheeling charges.

Support from the Oil Overcharge Settlement Fund. The Commission has applied to the Governor's Energy Office for funding from the Oil Overcharge Settlement Fund to support the following research activities:

1. **Electrical Emergencies Coordination.** Creation of an "Emergency Response Coordinator" position at the Commission will ensure better coordination of the state's electric utility industry's response to emergencies threatening the state's power supply.
2. **Electrical Resource Planning.** Continuation of the Commission's end-use modeling, bulk power transmission, and optimal systems analysis efforts will further enhance the forecasting and planning capabilities and identify potential energy and cost savings. The development of improved integrated resource planning capabilities at the Commission will facilitate emergency coordination planning during energy shortages.
3. **Transmission Line Siting.** This project will identify lost opportunities for energy savings attributable to the concern over the health effects of transmission, provide staffing for the Commission's Electromagnetic

Health Effects Committee, assist in monitoring electromagnetic fields around existing transmission and distribution lines in Texas, advance the Commission's efforts to map all high voltage transmission lines in Texas, and otherwise assist the Commission in conservation efforts and in protecting the health and safety of the citizens of Texas.

4. **Optimal Capacity and Fuel Planning.** Load and capacity resource projections developed by the Commission staff and the state's utilities indicate a need for additional generating capacity in Texas beginning in the late 1990s. This study will explore each utility's optimal fuel mix and the economics and environmental benefits of relying on Texas fuel resources.

5. **Rate Design Efficiency.** The cost of generating, transmitting, and distributing electricity varies from hour to hour. However, the retail price of electricity in Texas generally does not vary with the changing costs over short intervals. Considerable energy conservation and cost savings can be achieved by structuring electric rates so that they reflect the time-sensitive or usage-sensitive nature of the underlying costs. A more efficient price signal better conveys the true cost of using electricity. Efficient electricity prices benefit the consumer and the utility in the long run by lowering costs to both, and encouraging conservation at the times when demand is greatest.

6. **Energy Storage Technologies.** Energy storage systems offer many potential benefits to electric utilities and their customers, including reduction in generating capacity and spinning reserve requirements, reduction in the use of high-cost fuels for peaking power, more efficient operation of generating equipment during off-peak periods, and higher system reliability. Various technologies, including the superconducting magnetic energy storage device, are under development. In addition, thermal energy storage technologies are currently being implemented. These devices can be used to increase reliability and permit more efficient use of base load capacity. By assessing the capabilities of these devices and facilitating their implementation, the Commission could aid both utilities and consumers.

7. **Electric Load Data Demonstration Project (Remote Metering).** Through this project, the Commission staff and the state's utilities will jointly collect data on the load patterns of electricity users in Texas. End-use data will be recorded on solid state devices and accessed from remote locations using advanced communication technologies. These data, along with other load data provided by utilities, will be placed in a public data base for use by all parties. The data collected by this project will enhance conservation program analysis capabilities related to appropriate rate design, demand forecasting, and integrated resource planning.

8. **U.S.-Mexico Power Exchanges.** Increased electricity exchanges between the United States and Mexico might prove beneficial to both nations. Texas might benefit through the sale of power from presently underutilized generating capacity. Economy power imports from Mexico might serve to lower the cost of electricity to Texas ratepayers. Consideration of these opportunities will assist in the development of the national energy plan.

9. **Evaluation Criteria for Electrical Resource Alternatives.** The current practice of evaluating conservation and load management resource options with cost-benefit criteria creates an unfair barrier to the integration of demand-side resources in utility planning. Considerable energy conservation and cost savings can be achieved from the evaluation of both demand-side and supply-side options using similar criteria for selection and implementation in integrated resource planning. By providing utility planners with consistent guidelines for selecting among all resource options, optimal integrated resource planning in the state will be advanced.

Incentives for Conservation. Chapter 5 discusses the benefits of conservation programs to encourage the efficient use of electricity by customers. The Commission staff's recommended resource plan (Chapter 6) does not include any conservation program impacts beyond those in progress or planned by the state's utilities. Recent research conducted by Electric Power Research Institute indicates that demand-side management has a significant potential to reduce peak demand and conserve energy during the 1990s. Commission staff believes that a savings will result through increased program activity. However, many of the state's utilities have been reluctant to pursue all reasonable and low-cost options. The Commission staff is presently reviewing the regulatory incentives employed at other state commissions to encourage the conservation of resources and end-use energy efficiency. A staff working paper on regulatory incentives and disincentives for conservation will be prepared and submitted to the Commission in February 1991.

APPENDIX A

Appendix tables to Volume 1 of the *Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas 1990.*

APPENDIX

TABLE A.1

PEAK DEMAND AND DEMAND ADJUSTMENTS

TU ELECTRIC COMPANY

(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments.
1989	16,944					16,944
1990	17,874	106	292	75	473	17,401
1991	18,183	127	331	174	632	17,551
1992	18,633	149	351	259	759	17,874
1993	19,305	187	370	320	877	18,428
1994	19,770	225	393	382	999	18,771
1995	20,416	254	417	464	1,135	19,281
1996	21,074	282	440	556	1,278	19,796
1997	21,737	307	465	648	1,420	20,317
1998	22,381	332	489	746	1,567	20,814
1999	23,012	332	514	845	1,691	21,321
2000	23,763	332	538	948	1,818	21,945

TABLE A.2

INSTALLED CAPACITY

TU ELECTRIC COMPANY

(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	12,544		5,845				18,389
1990	12,934		5,845	1,150			19,929
1991	12,934		5,845	1,150			19,929
1992	12,934		5,845	1,150			19,929
1993	12,934		5,845	2,300			21,079
1994	12,934		5,845	2,300			21,079
1995	12,658		5,845	2,300			20,803
1996	12,513		6,595	2,300			21,408
1997	12,888		6,595	2,300			21,783
1998	12,719		7,345	2,300			22,364
1999	12,719		8,095	2,300			23,114
2000	12,651	650	8,095	2,300			23,696

TABLE A.3

NET SYSTEM CAPACITY AND RESERVE MARGINS
TU ELECTRIC COMPANY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	50	2,009		20,448	20.68%	18.00%	454
1990		2,016		21,945	26.11%	20.00%	1,063
1991		1,316		21,245	21.04%	20.00%	183
1992		1,526		21,455	20.04%	20.00%	6
1993		1,316		22,395	21.53%	20.00%	282
1994		1,316		22,395	19.31%	18.00%	246
1995		1,956		22,759	18.04%	18.00%	7
1996		1,959		23,367	18.04%	18.00%	8
1997		2,209		23,992	18.09%	18.00%	18
1998		2,209		24,573	18.06%	18.00%	13
1999		2,094		25,208	18.23%	18.00%	49
2000		2,200		25,896	18.00%	18.00%	1

TABLE A.4

PEAK DEMAND AND DEMAND ADJUSTMENTS

HOUSTON LIGHTING AND POWER COMPANY

(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments				Peak Demand After Adjustments
		Exogenous Factors	Active DSM	Passive DSM	Total	
1989	10,456					10,456
1990	11,595	-24	928	3	907	10,688
1991	11,704	-17	659	17	659	11,045
1992	11,890	-10	639	40	669	11,221
1993	12,084	1	736	76	813	11,271
1994	12,359	13	745	121	879	11,480
1995	12,758	21	765	168	954	11,804
1996	13,210	30	855	197	1,081	12,129
1997	13,668	37	898	225	1,159	12,509
1998	14,101	45	943	251	1,238	12,863
1999	14,617	45	986	278	1,308	13,309
2000	15,121	45	1,022	301	1,367	13,754

TABLE A.5

INSTALLED CAPACITY

HOUSTON LIGHTING AND POWER COMPANY

(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	9,099	2,335	1,440	770			13,644
1990	9,099	2,335	1,440	770			13,644
1991	9,099	2,335	1,440	770			13,644
1992	9,099	2,335	1,440	770			13,644
1993	9,099	2,335	1,440	770			13,644
1994	9,099	2,335	1,440	770			13,644
1995	9,099	2,335	1,440	770			13,644
1996	9,099	2,335	1,440	770			13,644
1997	9,259	2,335	1,440	770			13,804
1998	9,259	2,335	2,085	770			14,449
1999	9,419	2,335	2,085	770			14,609
2000	9,419	2,335	2,085	770			14,609

TABLE A.6

NET SYSTEM CAPACITY AND RESERVE MARGINS
HOUSTON LIGHTING AND POWER COMPANY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989		820		14,464	38.33%	20.00%	1,917
1990		956		14,600	36.60%	20.00%	1,775
1991		956		14,600	32.19%	18.00%	1,567
1992		956		14,600	30.11%	18.00%	1,359
1993		956		14,600	29.54%	18.00%	1,300
1994		731		14,375	25.21%	18.00%	828
1995		375		14,019	18.76%	18.00%	90
1996		865		14,509	19.62%	18.00%	197
1997		966		14,770	18.08%	18.00%	9
1998		830		15,279	18.78%	18.00%	101
1999		1,200		15,809	18.79%	18.00%	105
2000		1,620		16,229	18.00%	18.00%	0

TABLE A.7

PEAK DEMAND AND DEMAND ADJUSTMENTS
GULF STATES UTILITIES COMPANY- TOTAL SYSTEM
(MW)

Year	Total Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand Aafter Adjustments
1989	4,970					4,970
1990	5,093	-29	97		68	5,025
1991	5,133	-26	83		57	5,076
1992	5,114	-23	83		60	5,054
1993	5,175	-19	83		64	5,111
1994	5,261	-14	83		69	5,192
1995	5,343	-10	83		73	5,270
1996	5,411	-7	83		76	5,335
1997	5,478	-4	83		79	5,399
1998	5,541	-1	83		82	5,459
1999	5,619	-1	95		94	5,525
2000	5,710	-1	95		94	5,616

TABLE A.8

INSTALLED CAPACITY
GULF STATES UTILITIES COMPANY - TOTAL SYSTEM
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	5,171	612		655			6,438
1990	5,125	612		655			6,392
1991	5,125	612		655			6,392
1992	5,125	612		655			6,392
1993	5,125	612		655			6,392
1994	5,125	627		688			6,440
1995	5,125	627		688			6,440
1996	5,125	627		688			6,440
1997	5,125	627		688			6,440
1998	5,125	627		688			6,440
1999	5,175	627		688			6,490
2000	5,175	627		688			6,490

TABLE A.9

NET SYSTEM CAPACITY AND RESERVE MARGINS

GULF STATES UTILITIES COMPANY - TOTAL SYSTEM

(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	181	11	21	6,609	32.98%	15.25%	881
1990	145	11		6,548	30.31%	15.25%	757
1991	87	11		6,490	27.86%	15.25%	640
1992	77	11		6,480	28.22%	15.25%	655
1993	77	11		6,480	26.79%	15.25%	590
1994	66	11		6,517	25.52%	15.25%	533
1995	66	11		6,517	23.66%	15.25%	443
1996	46	11		6,497	21.78%	15.25%	348
1997	46	11		6,497	20.34%	15.25%	275
1998	46	11		6,497	19.01%	15.25%	206
1999	46	11		6,547	18.50%	15.25%	179
2000	144	11		6,645	18.32%	15.25%	173

TABLE A.10

PEAK DEMAND AND DEMAND ADJUSTMENTS

GULF STATES UTILITIES COMPANY - TEXAS SYSTEM

(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments				Peak Demand After Adjustments
		Exogenous Factors	Active DSM	Passive DSM	Total	
1989	2,194					2,194
1990	2,276	-14	59		45	2,231
1991	2,291	-13	63		50	2,241
1992	2,248	-12	63		51	2,197
1993	2,274	-9	63		54	2,220
1994	2,308	-7	63		56	2,252
1995	2,346	-5	63		58	2,288
1996	2,381	-3	63		60	2,321
1997	2,415	-2	63		61	2,354
1998	2,448		63		63	2,385
1999	2,494		63		63	2,431
2000	2,535		63		63	2,472

TABLE A.11

INSTALLED CAPACITY
GULF STATES UTILITIES COMPANY - TEXAS SYSTEM
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Allocation Factor	Total Texas Allocated Generating Capacity
1989	5,171	612		655		44.51%	2,865
1990	5,125	612		655		45.17%	2,887
1991	5,125	612		655		45.53%	2,911
1992	5,125	612		655		44.90%	2,870
1993	5,125	612		655		45.10%	2,883
1994	5,125	627		688		45.31%	2,918
1995	5,125	627		688		45.34%	2,920
1996	5,125	627		688		45.42%	2,925
1997	5,125	627		688		44.09%	2,839
1998	5,125	627		688		44.18%	2,845
1999	5,175	627		688		44.39%	2,881
2000	5,175	627		688		44.40%	2,881

TABLE A.12

NET SYSTEM CAPACITY AND RESERVE MARGINS
GULF STATES UTILITIES COMPANY - TEXAS SYSTEM
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	81	5	9	2,942	34.07%	15.25%	413
1990	65	5		2,957	32.54%	15.25%	386
1991	40	5		2,955	31.87%	15.25%	372
1992	35	5		2,909	32.43%	15.25%	377
1993	35	5		2,923	31.65%	15.25%	364
1994	30	5		2,953	31.12%	15.25%	357
1995	30	5		2,955	29.14%	15.25%	318
1996	21	5		2,951	27.13%	15.25%	276
1997	20	5		2,864	21.67%	15.25%	151
1998	20	5		2,870	20.35%	15.25%	122
1999	20	5		2,906	19.54%	15.25%	104
2000	64	5		2,950	19.34%	15.25%	101

TABLE A.13

PEAK DEMAND AND DEMAND ADJUSTMENTS
CENTRAL POWER AND LIGHT COMPANY
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1989	2,957					2,957
1990	3,088	-23	185	2	164	2,924
1991	3,217	-20	231	4	215	3,002
1992	3,365	-17	268	7	258	3,107
1993	3,480	-12	272	10	270	3,210
1994	3,605	-7	277	12	282	3,323
1995	3,726	-3	282	14	293	3,433
1996	3,824	1	287	17	305	3,519
1997	3,926	4	292	19	315	3,611
1998	4,040	7	296	21	324	3,716
1999	4,173	7	301	24	332	3,841
2000	4,308	7	306	27	340	3,968

TABLE A.14

INSTALLED CAPACITY
CENTRAL POWER AND LIGHT COMPANY
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	3,109	654		630	6		4,399
1990	3,109	654		630	6		4,399
1991	3,109	654		630	6		4,399
1992	3,109	654		630	6		4,399
1993	3,109	654		630	6		4,399
1994	3,109	654		630	6		4,399
1995	3,109	654		630	6		4,399
1996	3,062	654		630	6		4,352
1997	3,062	654		630	6		4,352
1998	3,152	654		630	6		4,442
1999	3,152	654		630	6		4,442
2000	3,152	654		630	6		4,442

TABLE A.15

NET SYSTEM CAPACITY AND RESERVE MARGINS

CENTRAL POWER AND LIGHT COMPANY

(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989				4,399	48.77%	19.22%	874
1990				4,399	50.46%	19.22%	913
1991				4,399	46.55%	18.73%	835
1992				4,399	41.60%	18.20%	727
1993				4,399	37.06%	17.93%	614
1994			5	4,394	32.24%	17.55%	488
1995			10	4,389	27.86%	17.10%	369
1996			19	4,333	23.12%	16.66%	227
1997			25	4,327	19.82%	16.27%	128
1998			41	4,401	18.44%	15.89%	95
1999		175	164	4,453	15.93%	15.45%	19
2000		175	51	4,566	15.06%	15.07%	0

TABLE A.16

PEAK DEMAND AND DEMAND ADJUSTMENTS
CITY PUBLIC SERVICE - SAN ANTONIO
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1989	2,697					2,697
1990	2,762	14	10		24	2,738
1991	2,868	17	10		27	2,841
1992	2,980	20	10		30	2,950
1993	3,090	25	10		35	3,055
1994	3,197	30	10		40	3,157
1995	3,305	34	10		44	3,261
1996	3,412	38	10		48	3,364
1997	3,523	41	10		51	3,472
1998	3,640	44	10		54	3,586
1999	3,781	44	10		54	3,727
2000	3,908	44	10		54	3,854

TABLE A.17

INSTALLED CAPACITY
CITY PUBLIC SERVICE - SAN ANTONIO
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	2,385	810		700			3,895
1990	2,385	810		700			3,895
1991	2,385	810		700			3,895
1992	2,385	810		700			3,895
1993	2,385	810		700			3,895
1994	2,385	810		700			3,895
1995	2,385	810		700			3,895
1996	2,385	810		700			3,895
1997	2,385	1,308		700			4,393
1998	2,385	1,308		700			4,393
1999	2,385	1,308		700			4,393
2000	2,455	1,308		700			4,463

TABLE A.18

NET SYSTEM CAPACITY AND RESERVE MARGINS
CITY PUBLIC SERVICE - SAN ANTONIO
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	100		325	3,670	36.08%	15.00%	568
1990				3,895	42.26%	15.00%	746
1991				3,895	37.10%	15.00%	628
1992				3,895	32.03%	15.00%	503
1993				3,895	27.50%	15.00%	382
1994				3,895	23.38%	15.00%	264
1995				3,895	19.44%	15.00%	145
1996				3,895	15.78%	15.00%	26
1997				4,393	26.53%	15.00%	400
1998				4,393	22.50%	15.00%	269
1999				4,393	17.87%	15.00%	107
2000				4,463	15.80%	15.00%	31

TABLE A.19

PEAK DEMAND AND DEMAND ADJUSTMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL SYSTEM

(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1989	2,989					2,989
1990	2,964	5	33	0	38	2,926
1991	3,017	6	33	0	39	2,978
1992	3,062	7	33	1	41	3,021
1993	3,105	9	33	1	43	3,062
1994	3,164	11	33	1	45	3,119
1995	3,237	13	33	1	47	3,190
1996	3,275	14	33	1	48	3,227
1997	3,312	15	33	2	50	3,262
1998	3,347	16	33	2	51	3,296
1999	3,382	16	33	2	51	3,331
2000	3,418	16	33	2	51	3,367

TABLE A.20

INSTALLED CAPACITY

SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL SYSTEM

(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	1,876	2,175					4,051
1990	1,886	2,175					4,061
1991	1,886	2,175					4,061
1992	1,886	2,175					4,061
1993	1,642	2,419					4,061
1994	1,642	2,419					4,061
1995	1,642	2,419					4,061
1996	1,642	2,419					4,061
1997	1,642	2,419					4,061
1998	1,642	2,419					4,061
1999	1,642	2,419					4,061
2000	1,642	2,419					4,061

TABLE A.21

NET SYSTEM CAPACITY AND RESERVE MARGINS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL SYSTEM
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	200			4,251	42.22%	18.00%	724
1990				4,061	38.80%	18.00%	609
1991				4,061	36.38%	18.00%	547
1992				4,061	34.40%	18.00%	496
1993				4,061	32.61%	18.00%	447
1994				4,061	30.20%	18.00%	380
1995				4,061	27.31%	18.00%	297
1996				4,061	25.86%	18.00%	254
1997				4,061	24.48%	18.00%	211
1998				4,061	23.20%	18.00%	171
1999				4,061	21.92%	18.00%	130
2000				4,061	20.61%	18.00%	88

TABLE A.22

PEAK DEMAND AND DEMAND ADJUSTMENTS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS SYSTEM
(MW)

		Demand Adjustments				
Year	Peak Demand Before Adjustments	Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1989	2,233					2,233
1990	2,194	4	33	0	37	2,157
1991	2,233	5	33	0	38	2,195
1992	2,266	5	33	1	39	2,227
1993	2,298	7	33	1	41	2,257
1994	2,329	8	33	1	42	2,287
1995	2,359	9	33	1	43	2,316
1996	2,388	10	33	1	44	2,344
1997	2,415	11	33	2	46	2,369
1998	2,442	12	33	2	47	2,395
1999	2,469	12	33	2	47	2,422
2000	2,497	12	33	2	47	2,449

TABLE A.23

INSTALLED CAPACITY
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS SYSTEM
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Allocation Factor	Texas Allocated Installed Generating Capacity
1989	1,876	2,175				74.71%	3,026
1990	1,886	2,175				74.02%	3,006
1991	1,886	2,175				74.01%	3,006
1992	1,886	2,175				74.00%	3,005
1993	1,642	2,419				74.01%	3,006
1994	1,642	2,419				73.61%	2,989
1995	1,642	2,419				72.88%	2,960
1996	1,642	2,419				72.92%	2,961
1997	1,642	2,419				72.92%	2,961
1998	1,642	2,419				72.96%	2,963
1999	1,642	2,419				73.00%	2,965
2000	1,642	2,419				73.07%	2,966

TABLE A.24

NET SYSTEM CAPACITY AND RESERVE MARGINS
SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS SYSTEM
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	149			3,176	42.22%	18.00%	541
1990				3,006	39.37%	18.00%	461
1991				3,006	36.95%	18.00%	416
1992				3,005	34.92%	18.00%	377
1993				3,006	33.15%	18.00%	342
1994				2,989	30.70%	18.00%	291
1995				2,960	27.79%	18.00%	227
1996				2,961	26.34%	18.00%	196
1997				2,961	24.97%	18.00%	165
1998				2,963	23.70%	18.00%	137
1999				2,965	22.41%	18.00%	107
2000				2,966	21.09%	18.00%	76

TABLE A.25

PEAK DEMAND AND DEMAND ADJUSTMENTS

SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL SYSTEM

(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1989	2,812					2,812
1990	3,075	10	48		58	3,017
1991	3,122	12	48		60	3,062
1992	3,203	14	48		62	3,141
1993	3,306	18	48		66	3,240
1994	3,400	21	48		69	3,331
1995	3,494	24	48		72	3,422
1996	3,591	26	48		74	3,517
1997	3,696	29	48		77	3,619
1998	3,816	31	48		79	3,737
1999	3,958	31	48		79	3,879
2000	4,081	31	48		79	4,002

TABLE A.26

INSTALLED CAPACITY

SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL SYSTEM

(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	1,819	1,824	821				4,464
1990	1,819	1,824	821				4,464
1991	1,819	1,824	821				4,464
1992	1,819	1,824	821				4,464
1993	1,819	1,824	821				4,464
1994	1,819	1,824	821				4,464
1995	1,819	1,824	821				4,464
1996	1,819	1,824	821				4,464
1997	1,819	1,824	821				4,464
1998	1,819	1,824	821				4,464
1999	1,819	1,824	821				4,464
2000	1,993	1,824	821				4,638

TABLE A.27

NET SYSTEM CAPACITY AND RSERVE MARGINS

SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL SYSTEM

(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	30		16	4,478	59.25%	15.00%	1,244
1990			21	4,443	47.27%	15.00%	973
1991			21	4,443	45.10%	15.00%	922
1992			21	4,443	41.45%	15.00%	831
1993			21	4,443	37.13%	15.00%	717
1994			40	4,424	32.81%	15.00%	593
1995			74	4,390	28.29%	15.00%	455
1996			83	4,381	24.57%	15.00%	336
1997			43	4,421	22.16%	15.00%	259
1998			91	4,373	17.02%	15.00%	75
1999	27		30	4,461	15.00%	15.00%	0
2000	13	5	54	4,602	14.99%	15.00%	0

TABLE A.28

PEAK DEMAND AND DEMAND ADJUSTMENTS

SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS SYSTEM

(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1989	1,407					1,407
1990	1,534	4	45		49	1,485
1991	1,586	5	45		50	1,536
1992	1,633	6	45		51	1,582
1993	1,690	7	45		52	1,638
1994	1,755	9	45		54	1,701
1995	1,821	10	45		55	1,766
1996	1,886	11	45		56	1,830
1997	1,951	12	45		57	1,894
1998	2,017	13	45		58	1,959
1999	2,086	13	45		58	2,028
2000	2,150	13	45		58	2,092

TABLE A.29

INSTALLED CAPACITY
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS SYSTEM
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Allocation Factor	Texas Allocated Installed Generating Capacity
1989	1,819	1,824	821			50.04%	2,234
1990	1,819	1,824	821			49.89%	2,227
1991	1,819	1,824	821			50.80%	2,268
1992	1,819	1,824	821			50.98%	2,276
1993	1,819	1,824	821			51.12%	2,282
1994	1,819	1,824	821			51.62%	2,304
1995	1,819	1,824	821			52.12%	2,327
1996	1,819	1,824	821			52.52%	2,345
1997	1,819	1,824	821			52.79%	2,356
1998	1,819	1,824	821			52.86%	2,360
1999	1,819	1,824	821			52.70%	2,353
2000	1,993	1,824	821			52.68%	2,443

TABLE A.30

NET SYSTEM CAPACITY AND RESERVE MARGINS
SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS SYSTEM
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	15		8	2,241	59.25%	15.00%	623
1990			11	2,216	49.25%	15.00%	509
1991			11	2,257	46.94%	15.00%	491
1992			11	2,265	43.19%	15.00%	446
1993			11	2,271	38.66%	15.00%	388
1994			21	2,284	34.25%	15.00%	327
1995			39	2,288	29.55%	15.00%	257
1996			44	2,301	25.73%	15.00%	196
1997			23	2,334	23.22%	15.00%	156
1998			48	2,311	17.99%	15.00%	59
1999	14		16	2,351	15.93%	15.00%	19
2000	7	3	28	2,424	15.89%	15.00%	19

TABLE A.31

PEAK DEMAND AND DEMAND ADJUSTMENTS
LOWER COLORADO RIVER AUTHORITY
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments				Peak Demand After Adjustments
		Exogenous Factors	Active DSM	Passive DSM	Total	
1989	1,568					1,568
1990	1,567	11	19	3	33	1,534
1991	1,601	14	25	8	47	1,554
1992	1,667	16	31	14	60	1,607
1993	1,738	20	37	18	75	1,663
1994	1,827	24	44	24	92	1,735
1995	1,923	27	51	32	110	1,813
1996	2,012	31	58	37	126	1,886
1997	2,108	33	66	43	142	1,966
1998	2,205	36	70	51	157	2,048
1999	2,326	36	75	56	167	2,159
2000	2,418	36	79	62	176	2,242

TABLE A.32

INSTALLED CAPACITY
LOWER COLORADO RIVER AUTHORITY
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	1,025	1,008			241		2,274
1990	1,025	1,008			241		2,274
1991	1,025	1,008			241		2,274
1992	1,025	1,008			241		2,274
1993	1,025	1,008			241		2,274
1994	1,025	1,008			241		2,274
1995	1,025	1,008			241		2,274
1996	1,025	1,008			241		2,274
1997	1,025	1,008			241		2,274
1998	1,025	1,008			241		2,274
1999	1,025	1,008			241		2,274
2000	1,152	1,008			241		2,401

TABLE A.33

NET SYSTEM CAPACITY AND RESERVE MARGINS
LOWER COLORADO RIVER AUTHORITY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989				2,274	45.03%	15.00%	471
1990				2,274	48.23%	15.00%	510
1991				2,274	46.30%	15.00%	486
1992				2,274	41.55%	15.00%	426
1993				2,274	36.75%	15.00%	362
1994				2,274	31.07%	15.00%	279
1995				2,274	25.41%	15.00%	189
1996				2,274	20.56%	15.00%	105
1997				2,274	15.65%	15.00%	13
1998		82		2,356	15.06%	15.00%	1
1999	29	180		2,483	14.99%	15.00%	0
2000		180		2,581	15.13%	15.00%	3

TABLE A.34

PEAK DEMAND AND DEMAND ADJUSTMENTS
CITY OF AUSTIN
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1989	1,408					1,408
1990	1,501		2	13	15	1,486
1991	1,523		2	29	31	1,492
1992	1,569		2	47	49	1,520
1993	1,627		3	65	68	1,559
1994	1,695		3	85	88	1,607
1995	1,772		4	113	117	1,655
1996	1,849		5	143	148	1,701
1997	1,925		5	174	179	1,746
1998	2,001		6	205	211	1,790
1999	2,091		6	235	241	1,850
2000	2,187		7	262	269	1,918

TABLE A.35

INSTALLED CAPACITY
CITY OF AUSTIN
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	1,550	578		400		0	2,528
1990	1,550	578		400		0	2,528
1991	1,514	578		400		0	2,492
1992	1,514	578		400		0	2,492
1993	1,514	578		400		0	2,492
1994	1,514	578		400		0	2,492
1995	1,486	578		400		0	2,464
1996	1,486	578		400		0	2,464
1997	1,486	578		400		0	2,464
1998	1,450	578		400		0	2,428
1999	1,450	578		400		0	2,428
2000	1,353	578		400		0	2,331

APPENDIX

TABLE A.36

NET SYSTEM CAPACITY AND RESERVE MARGINS

CITY OF AUSTIN

(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989			10	2,518	78.82%	15.00%	899
1990			15	2,513	70.36%	15.00%	817
1991			15	2,477	66.90%	15.00%	770
1992			15	2,477	62.95%	15.00%	729
1993			15	2,477	58.16%	15.00%	676
1994			15	2,477	52.79%	15.00%	613
1995			15	2,449	45.42%	15.00%	512
1996			15	2,449	40.17%	15.00%	440
1997				2,464	36.35%	15.00%	386
1998				2,428	29.90%	15.00%	278
1999				2,428	24.95%	15.00%	193
2000				2,331	15.16%	15.00%	3

TABLE A.37

PEAK DEMAND AND DEMAND ADJUSTMENTS
WEST TEXAS UTILITIES COMPANY
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1989	1,134					1,134
1990	1,158	5		1	6	1,152
1991	1,176	6		2	8	1,168
1992	1,197	7		3	10	1,187
1993	1,223	9		3	12	1,211
1994	1,255	11		4	15	1,240
1995	1,290	12		5	17	1,273
1996	1,326	14		6	20	1,306
1997	1,364	15		7	22	1,342
1998	1,402	16		8	24	1,378
1999	1,444	16		9	25	1,419
2000	1,486	16		11	27	1,459

TABLE A.38

INSTALLED CAPACITY
WEST TEXAS UTILITIES COMPANY
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	1,035	364					1,399
1990	1,035	364					1,399
1991	1,035	364					1,399
1992	1,035	364					1,399
1993	1,035	364					1,399
1994	1,035	364					1,399
1995	1,035	364					1,399
1996	1,035	364					1,399
1997	1,127	364					1,491
1998	1,070	364					1,434
1999	1,111	364					1,475
2000	1,246	364					1,610

TABLE A.39

NET SYSTEM CAPACITY AND RESERVE MARGINS
WEST TEXAS UTILITIES COMPANY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	14			1,413	24.60%	15.00%	109
1990				1,399	21.42%	15.00%	74
1991				1,399	19.75%	15.00%	55
1992				1,399	17.82%	15.00%	33
1993				1,399	15.57%	15.00%	7
1994	27			1,426	15.04%	15.00%	0
1995	65			1,464	15.04%	15.00%	0
1996	103			1,502	15.04%	15.00%	0
1997	52			1,543	15.01%	15.00%	0
1998	150			1,584	14.98%	15.00%	0
1999	156			1,631	14.97%	15.00%	0
2000	51	17		1,678	14.97%	15.00%	0

TABLE A.40

PEAK DEMAND AND DEMAND ADJUSTMENTS

EL PASO ELECTRIC COMPANY - TOTAL SYSTEM

(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1989	923					923
1990	952	2			2	950
1991	982	3			3	979
1992	1,005	4		0	4	1,001
1993	1,037	4		0	4	1,033
1994	1,075	5		0	5	1,070
1995	1,108	6		0	6	1,102
1996	1,137	7		1	8	1,129
1997	1,161	7		1	8	1,153
1998	1,190	8		1	9	1,181
1999	1,221	8		1	9	1,212
2000	1,250	8		1	9	1,241

TABLE A.41

INSTALLED CAPACITY

EL PASO ELECTRIC COMPANY - TOTAL SYSTEM

(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	794	104		600			1,498
1990	793	104		600			1,497
1991	793	104		600			1,497
1992	793	104		600			1,497
1993	793	104		600			1,497
1994	793	104		600			1,497
1995	793	104		600			1,497
1996	863	104		600			1,567
1997	863	104		600			1,567
1998	933	104		600			1,637
1999	933	104		600			1,637
2000	1,013	104		600			1,717

TABLE A.42

NET SYSTEM CAPACITY AND RSERVE MARGINS
EL PASO ELECTRIC COMPANY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	0		162	1,336	44.75%	27.00%	164
1990	0		166	1,331	40.11%	27.00%	125
1991	0		171	1,326	35.44%	26.00%	92
1992	0		177	1,320	31.90%	25.00%	69
1993	0		182	1,315	27.33%	25.00%	24
1994	18		178	1,337	25.00%	25.00%	0
1995	47		178	1,366	24.00%	24.00%	0
1996	11		178	1,400	23.96%	24.00%	0
1997	30		178	1,419	23.03%	23.00%	0
1998	0		178	1,459	23.52%	23.00%	6
1999	20		178	1,479	22.02%	22.00%	0
2000	0		178	1,539	24.02%	22.00%	25

TABLE A.43

PEAK DEMAND AND DEMAND ADJUSTMENTS
EL PASO ELECTRIC COMPANY - TEXAS SYSTEM
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments				Peak Demand After Adjustments
		Exogenous Factors	Active DSM	Passive DSM	Total	
1989	743					743
1990	758	2			2	756
1991	780	2			2	778
1992	795	3		0	3	792
1993	819	3		0	3	816
1994	847	4		0	4	843
1995	874	5		0	5	869
1996	897	5		1	6	891
1997	916	5		1	6	910
1998	940	6		1	7	933
1999	965	6		1	7	958
2000	990	6		1	7	983

TABLE A.44

INSTALLED CAPACITY
EL PASO ELECTRIC COMPANY - TEXAS SYSTEM
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Allocation Factor	Texas Allocated Installed Generating Capacity
1989	794	104		600		80.50%	1,206
1990	793	104		600		79.62%	1,192
1991	793	104		600		79.43%	1,189
1992	793	104		600		79.10%	1,184
1993	793	104		600		78.98%	1,182
1994	793	104		600		78.79%	1,180
1995	793	104		600		78.88%	1,181
1996	863	104		600		78.89%	1,236
1997	863	104		600		78.90%	1,236
1998	933	104		600		78.99%	1,293
1999	933	104		600		79.03%	1,294
2000	1,013	104		600		79.20%	1,360

TABLE A.45

NET SYSTEM CAPACITY AND RESERVE MARGINS
EL PASO ELECTRIC COMPANY - TEXAS SYSTEM
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1989	0		130	1,076	44.75%	27.00%	132
1990	0		132	1,060	40.17%	27.00%	100
1991	0		136	1,053	35.39%	26.00%	73
1992	0		140	1,044	31.88%	25.00%	54
1993	0		144	1,039	27.31%	25.00%	19
1994	14		140	1,054	25.03%	25.00%	0
1995	37		140	1,078	24.05%	24.00%	0
1996	9		140	1,105	23.91%	24.00%	0
1997	24		140	1,120	22.98%	23.00%	0
1998	0		141	1,153	23.51%	23.00%	5
1999	16		141	1,169	22.00%	22.00%	0
2000	0		141	1,219	24.01%	22.00%	20

TABLE A.46

PEAK DEMAND AND DEMAND ADJUSTMENTS

TEXAS-NEW MEXICO POWER COMPANY - TEXAS SYSTEM

(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1989	968					968
1990	1,010	6		1	7	1,003
1991	1,029	7		2	9	1,020
1992	1,040	9		5	14	1,026
1993	1,056	11		7	18	1,038
1994	1,076	13		9	22	1,054
1995	1,098	15		11	26	1,072
1996	1,118	16		13	29	1,089
1997	1,155	18		15	33	1,122
1998	1,195	19		18	37	1,158
1999	1,230	19		20	39	1,191
2000	1,261	19		22	41	1,220

TABLE A.47

INSTALLED CAPACITY

TEXAS-NEW MEXICO POWER COMPANY - TEXAS SYSTEM

(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989							
1990			146				146
1991			291				291
1992			291				291
1993			291				291
1994			291				291
1995			291				291
1996			291				291
1997			291				291
1998			291				291
1999			291				291
2000			291				291

TABLE A.48

NET SYSTEM CAPACITY AND RESERVE MARGINS
TEXAS-NEW MEXICO POWER COMPANY - TEXAS SYSTEM
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin * (%)	Target Reserve (%)	Excess Capacity
1989	633	335		968	0.0%	15%	0
1990	641	216		1,003	0.0%	15%	0
1991	487	242		1,020	0.0%	15%	0
1992	447	288		1,026	0.0%	15%	0
1993	433	314		1,038	0.0%	15%	0
1994	439	324		1,054	0.0%	15%	0
1995	506	275		1,072	0.0%	15%	0
1996	512	286		1,089	0.0%	15%	0
1997	415	416		1,122	0.0%	15%	0
1998	433	434		1,158	0.0%	15%	0
1999	449	450		1,191	0.0%	15%	0
2000	462	466		1,219	0.0%	15%	0

* TNP reserves are included with purchased power.

TABLE A.49

PEAK DEMAND AND DEMAND ADJUSTMENTS

BRAZOS ELECTR0IC POWER COOPERATIVE, INC.

(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1989	811					811
1990	874	5			5	869
1991	931	6			6	925
1992	970	8			8	962
1993	1,014	10			10	1,004
1994	1,047	11			11	1,036
1995	1,080	13			13	1,067
1996	1,117	14			14	1,103
1997	1,164	16			16	1,148
1998	1,207	17			17	1,190
1999	1,248	17			17	1,231
2000	1,287	17			17	1,270

TABLE A.50

INSTALLED CAPACITY

BRAZOS ELECTRIC POWER COOPERATIVE, INC.

(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	467						467
1990	467						467
1991	467						467
1992	467						467
1993	467						467
1994	674						674
1995	962						962
1996	962						962
1997	962						962
1998	962						962
1999	962						962
2000	962						962

TABLE A.51

NET SYSTEM CAPACITY AND RESERVE MARGINS
BRAZOS ELECTRIC POWER COOPERATIVE, INC.
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Reserve (%)	Target Reserve (%)	Excess Capacity
1989	635			1,102	35.88%	15.00%	169
1990	554			1,021	17.49%	15.00%	22
1991	596			1,063	14.98%	15.00%	0
1992	639			1,106	15.02%	15.00%	0
1993	687			1,154	14.99%	15.00%	0
1994	518			1,192	15.02%	15.00%	0
1995	266			1,228	15.04%	15.00%	0
1996	311			1,273	15.45%	15.00%	5
1997	359			1,321	15.03%	15.00%	0
1998	259	150		1,371	15.19%	15.00%	2
1999	259	200		1,421	15.45%	15.00%	6
2000	298	200		1,460	15.00%	15.00%	0

TABLE A.52

PEAK DEMAND AND DEMAND ADJUSTMENTS
TOTAL OF ALL OTHER TEXAS UTILITIES
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1989	2,369					2,369
1990	2,418		2		2	2,416
1991	2,463		3		3	2,460
1992	2,513		4		4	2,509
1993	2,558		5		5	2,553
1994	2,601		6		6	2,595
1995	2,648		6		6	2,642
1996	2,693		6		6	2,687
1997	2,738		6		6	2,732
1998	2,784		6		6	2,778
1999	2,826		6		6	2,820
2000	2,874		6		6	2,868

TABLE A.53

INSTALLED CAPACITY
TOTAL OF ALL OTHER TEXAS UTILITIES
(MW)

Year	Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1989	850	168	880		242		2,140
1990	870	211	910		249		2,240
1991	870	230	910		249		2,259
1992	870	240	910		249		2,269
1993	920	240	910		249		2,319
1994	920	250	910		249		2,329
1995	930	250	910		249	10	2,349
1996	930	270	910		249	10	2,369
1997	930	270	910		249	10	2,369
1998	930	270	910		249	10	2,369
1999	930	270	910		249	10	2,369
2000	930	270	910		249	10	2,369

TABLE A.54

NET SYSTEM CAPACITY AND RESERVE MARGINS
TOTAL OF ALL OTHER TEXAS UTILITIES
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Reserve (%)	Target Reserve (%)	Excess Capacity
1989	1,295		391	3,043	28.47%	15.00%	319
1990	1,042		401	2,882	19.27%	15.00%	103
1991	1,024		399	2,884	17.23%	15.00%	55
1992	1,085		408	2,946	17.42%	15.00%	61
1993	1,045		407	2,957	15.82%	15.00%	21
1994	1,066		410	2,984	15.00%	15.00%	0
1995	1,100		410	3,038	15.00%	15.00%	0
1996	1,131		410	3,090	15.00%	15.00%	0
1997	1,184		410	3,142	15.00%	15.00%	0
1998	1,236		410	3,194	15.00%	15.00%	0
1999	1,284		410	3,243	15.00%	15.00%	0
2000	1,340		410	3,298	15.00%	15.00%	0

APPENDIX B

Staff derived Annual Sales by Sector (MWH)

TABLE B.2

TOTAL TEXAS

ANNUAL SALES BY SECTOR (MWH)

AS DERIVED BY STAFF

Year	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)	Total Off-System
1989	66,681,670	54,154,830	79,377,313	39,911,922	240,125,735	4,275,034
1990	73,803,133	56,994,536	81,688,148	30,088,012	242,573,829	1,247,914
1991	75,031,351	58,011,641	83,270,049	30,834,120	247,147,160	1,723,875
1992	76,618,379	59,545,617	85,295,324	31,317,883	252,777,203	1,032,220
1993	78,624,671	61,768,208	87,126,768	32,000,553	259,520,200	1,185,386
1994	80,638,501	63,800,891	88,726,927	32,639,125	265,805,443	1,284,536
1995	83,146,047	66,161,152	90,958,398	33,368,375	273,633,972	1,538,675
1996	85,767,799	68,633,438	92,974,213	34,103,597	281,479,047	1,479,871
1997	88,411,773	71,273,886	94,962,261	34,814,243	289,462,163	1,573,363
1998	91,006,413	73,839,158	97,010,762	35,551,615	297,407,947	1,747,671
1999	94,124,057	76,458,861	99,225,942	36,246,277	306,055,137	1,978,507
2000	97,492,239	79,135,314	101,317,804	36,967,535	314,912,892	1,939,966