LONG-TERM ELECTRIC PEAK DEMAND AND CAPACITY RESOURCE FORECAST FOR TEXAS 1988

VOLUME II

A REVIEW OF CURRENT UTILITY-DEVELOPED LOAD FORECASTS AND CAPACITY RESOURCE PLAN

FEBRUARY 1989

THE PUBLIC UTILITY COMMISSION OF TEXAS

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Note: Partial funding for some of the research described in this three-volume report was secured from the U.S. Department of Energy through the 1988 State Energy Conservation Program.

ABSTRACT

Although electric utilities in Texas have entered a period of significant excess generating capacity, a number of planning issues deserve prompt attention. These issues include the future role of cogeneration in Texas, alleviating potential transmission bottlenecks in some areas of the State, the short-term and long-term implications associated with abandoning conservation programs in favor of promotional strategies, the appropriate degree of operating and planning coordination among the State's utilities, better utilization of the transmission system, and the potential for rate design to serve as a resource planning tool.

This report is designed to provide information and recommendations to policymakers and others interested in the present and future status of the Texas electric power industry. The first volume of this three volume report of the Commission staff's **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988** provides recommended electricity demand projections for twelve of the State's largest electric utilities and an independent recommended capacity resource plan for Texas. Fuel markets, cogeneration activity, and the potential loss of industrial loads are discussed along with a number of topics of special interest.

The second volume summarizes the electricity demand forecasts, energy efficiency plans, and capacity resource plans developed by Texas generating electric utilities and filed at the Commission in December 1987. The third volume provides a technical description of the staff's Econometric Electricity Demand Forecasting system and other models used by the staff to develop the recommended load forecast presented in this volume.

The 1984 and 1986 reports focused on two central themes: 1) the development of load forecasting methodologies, data, and models; and 2) capacity expansion through the construction of utility-owned generating units. The central theme of this 1988 report, in view of the lingering effects of the Texas recession, is how to achieve greater efficiency in the use of the State's electrical resources. Within this framework, substantially more emphasis is directed toward demand-side management approaches, alternative power and energy sources, and system economics. The information presented here attempts to capture the underlying philosophy, as well as the techniques, which are used to address these important issues and provide a focus on anticipated problems and opportunities.

It should be emphasized that the projections contained herein were prepared for planning purposes and do not reflect any official policy positions or predictions by the Commission.

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INTRODUCTION

The second volume of this three volume report, the **Long-Term Peak Demand and Capacity Resource Forecast for Texas 1988**, summarizes the electricity demand forecasts, energy efficiency plans, and capacity resource plans developed by the State's generating electric utilities and filed with the Public Utility Commission of Texas. The information was provided by each generating electric utility in the State pursuant to Section 16(c) of the Public Utility Regulatory Act (PURA). PURA mandates that every generating electric utility shall provide the following information to the Public Utility Commission of Texas (PUCT):

1) A description of methods and economic/demographic assumptions incorporated in the forecast and of projected population growth, urban development, industrial expansion, and other growth factors influencing the demand for electric energy in the service area

2) A list of existing electric generating plants in service with a description of planned and potential generating capacity at existing sites

3) Projected annual system capacity, peak load, interruptible load, and reserve margins

4) Forecasted annual load duration curves and peak loads for major demand sectors in the service area

5) Projected annual firm purchases and sales of capacity

6) A description of how electrical energy requirements indentified in the forecast will be met

7) Descriptions of current load management and conservation programs and efforts to encourage cogeneration and small power production

8) Such additional information (including historical data) deemed necessary to the evaluation of utility forecasts and resource plans and the development of the statewide electrical energy forecast

PURA requires the PUCT to compile and report the information, and this volume summarizes the data reported by the utilities in December 1987.

Abbreviations used throughout this volume include:

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

Chapters 2 through 14 summarize the reports of the above utilities. Chapter 15 discusses the other 16 generating utilities. The first section of each chapter discusses how the utility expects its peak demand to grow. The second section describes the generating capacity of the utility and any planned expansion.

This volume is intended as a summary of the utility filings only. The Public Utility Commission of Texas has not necessarily endorsed the utility-sponsored demand forecasts, demand-side management efforts, or capacity expansion plans described herein. Some changes to the numbers filed by the utilities have been made to increase comparability between the utilities, to interpolate missing numbers, or simply to correct misplaced numbers.

CHAPTER ONE

STATEWIDE SUMMARY

Total sales of electrical energy and peak demand on capacity in Texas are forecast by the generating utilities of Texas to achieve a 2.3 percent annual compound rate of growth through 1997. The sum of individual utility peaks in 1997 of 56,923 MW is projected to be 1,628 MW less than it would have been because of utility demand-side management activities. Savings through conservation efforts alone are expected to reduce the peak demand by 1,262 MW, about as much as the capacity of one large, nuclear generating unit. The utilities report that installed generation capacity should grow to 66,537 MW in 1997 from 53,934 MW in 1987, an increase of 12,603 MW or 23.4 percent over the 1987 capacity. The largest increase, 38.5 percent of the 12,603 MW of new installed capacity will come from nuclear power. The utilities expect to purchase 1,709 MW of capacity from cogenerators and small power producers in 1997, down from 2,718 MW in 1987. Reserve margins are expected to drop nearly seven percentage points to 21 in 1997 from the 1987 level of about 28 percent.

ERCOT plays a prominent role in the Texas utility industry, with ERCOT utilities servicing nearly 85 percent of the total peak demand in the State in 1987. ERCOT members include 20 municipalities, 51 cooperatives, six investor-owned utilities, and one state river authority. ERCOT is a self-contained grid system entirely within the State and with limited interconnections to other regional systems. The Western Systems Coordinating Council (WSCC) and the Southwest Power Pool (SPP) border ERCOT. Non-ERCOT Texas utilities belong to one or the other of the bordering reliability councils. ERCOT members BEPC, COA, CPL, CPS, HL&P, LCRA, TNP, TU, and WTU are covered in detail in this volume.

Determining the supply-side resources available for Texas is problematic because the non-ERCOT utilities operate across state boundaries. Extricating Texas-only numbers from the network can result in somewhat arbitrary totals. For the purposes of this volume, generating capacity, purchases, and sales have been allocated on the basis of the ratio of Texas demand to total system demand for MW capacity, or sales in Texas to total system sales in the case of MWH numbers. The totals for ERCOT utilities may be regarded as more certain than the Texas portion of the totals for the non-ERCOT utilities because allocations are not needed. However, generation by the Southwestern

Power Authority, the Guadalupe-Blanco River Authority, and the Brazos River Authority were included in the ERCOT totals even though these utilities are not members of ERCOT. These utilities sell power to members of ERCOT for distribution to ultimate customers.

1.1 DEMAND FORECAST

Number of Customers. The number of customers served by utilities in the State grew from 3,998,735 in 1977 to 6,149,272 in 1987. Table 1.1, *Number of Customers by Sector*, shows that every year the number of customers increased over the previous year, but the growth slowed considerably after 1984. The number of industrial customers actually fell after 1985, on into 1987. Overall, growth in the total number of customers will occur at a compound rate of 2 percent per year, according to the utilities' projections, to reach 7,652,273 in 1997.

COA experienced the highest growth rate in the number of residential electric customers over the 10-year period from 1977 to 1987 at a compound average of 6.3 percent per year. HL&P followed with a 5.3 percent rate, then San Antonio's CPS at 4.9 percent, and TU Electric, whose service area includes Dallas, at 3.9 percent. The slowest growing service area in terms of the number of residential customers was that of SPS, with a 10-year average annual growth rate of 1.2 percent, followed by SWEPCO, with a rate of 1.7 percent.

SPS expects the lowest rate of growth among the 13 major utilities in the number of residential customers over the next 10 years, projecting a rate of 0.15 percent annually through 1997. GSU also projects an increase of less than 1 percent per year for Texas (0.7 percent, actually) over the forecast period. SWEPCO expects the second fastest growth in the number of residential customers of any of the utilities, with a 2.8 percent rate. COA projects a growth rate of 5.5 percent per year through 1997. None of the utilities project rates over the next 10 years to be as large as those in the last 10 years.

Total Sales. Total system sales for all utility systems in the State grew at an annual compound rate of 3.6 percent over the past 10 years, reaching 225,500,141 MWH in 1987 from 159,553,987 MWH in 1977. As shown in Figure 1.1 and Table 1.2, Annual Sales by Sector, industrial sector sales slid for three years after a 1984 peak, and with flat sales in the residential sector and only slight growth in the commercial sector, total sales actually

TABLE 1.1
Number of customer by Sector
Texas Total

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	3,472,882	437,918	36,737	50,815	383
1978	3,818,722	491,313	39,837	69,436	409
1979	4,017,048	511,285	40,766	71,489	413
1980	4,211,695	530,860	43,196	71,874	491
1981	4,405,449	554,417	43,827	72,768	487
1982	4,594,139	581,535	45,645	74,809	402
1983	4,789,351	615,839	46,661	77,082	403
1984	5,015,045	644,516	48,803	79,064	403
1985	5,192,999	665,344	49,479	83,171	384
1986	5,303,799	675,611	48,981	72,965	383
1987	5,362,303	681,029	48,807	56,751	382
1988	5,466,776	691,749	50,445	56,149	351
1989	5,572,108	703,293	51,377	57,102	351
1990	5,695,334	716,079	51,447	58,095	350
1991	5,827,974	729,893	53,631	59,154	349
1992	5,961,493	743,709	54,885	60,207	348
1993	6,103,984	757,836	56,211	61,273	348
1994	6,249,869	772,225	57,605	62,352	347
1995	6,399,277	786,901	59,062	63,450	346
1996	6,549,702	801,822	60,600	64,562	345
1997	6,706,938	817,127	62,170	65,693	345

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

fell in 1986 from the 1985 level. All sectors are projected to show growth in 1988. Total system sales projections show an annual growth rate of 2.4 percent through 1997.

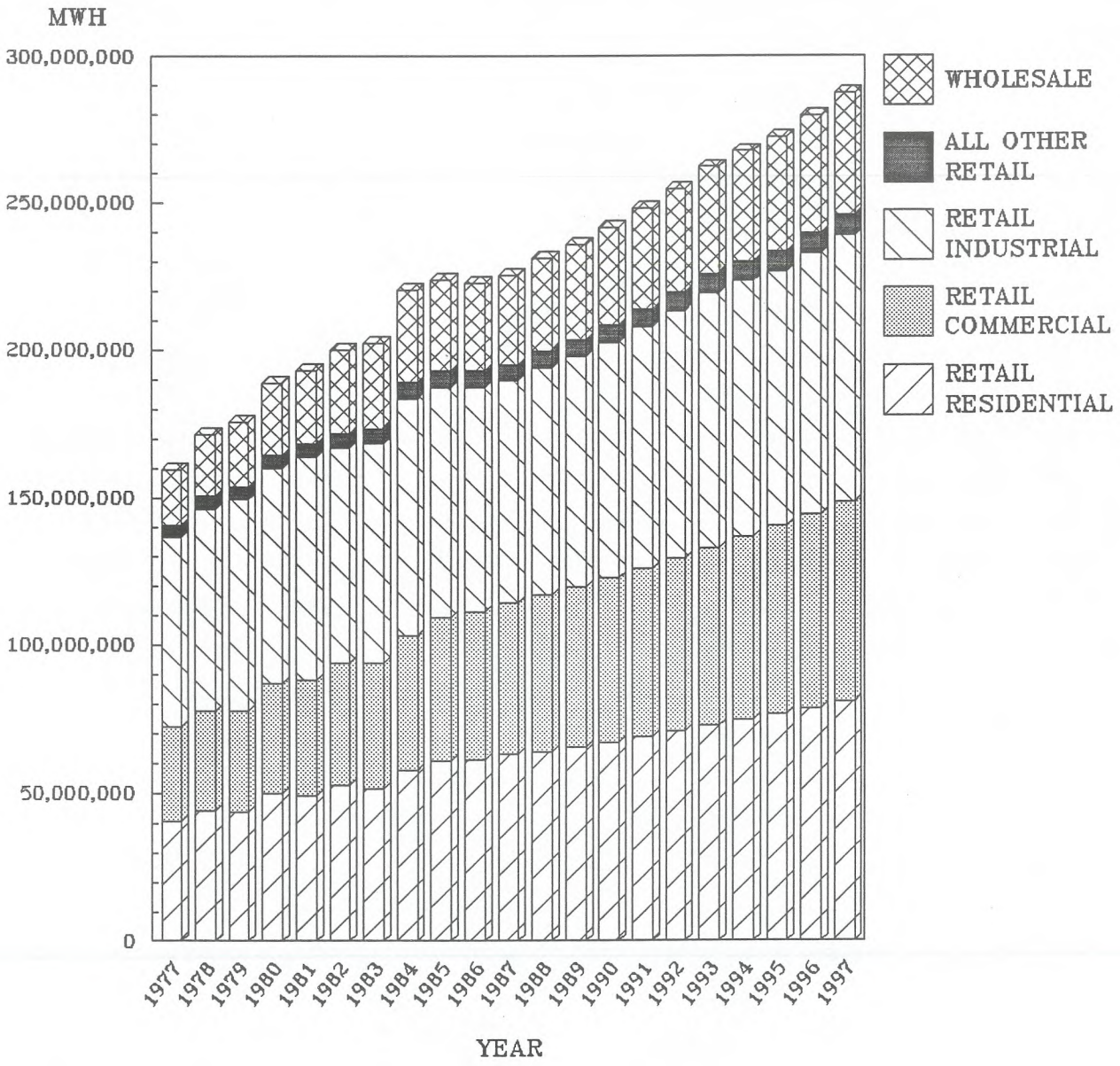
TU Electric is the largest utility in the State and sold 77,665,792 MWH in 1987, fully 34 percent of all the electricity sold by utilities, on system, in the State. HL&P shows the next highest level of total sales in 1987 with 54,912,601 MWH, 24 percent of the State total, followed, in order, by CPL, GSU, SPS, CPS, SWEPCO, LCRA, COA, WTU, TNP, BEPC, and EPE. The five largest utilities make 75 percent of annual sales by utilities in the State and the 13 largest utilities sell 96 percent of the total. The 16 utilities making up the "Other" category account for about 4 percent of the total sales in the State.

Sales to the residential sector amounted to 28 percent of all system sales in 1987. COA shows greater dependence upon the residential sector, with 39 percent of system sales to residences. CPS and TU Electric sell a bit over one-third of their system totals to residential customers, and TNP a little under one-third. SPS sells only 15 percent of total system sales to its residential sector, and GSU, 23 percent.

Commercial sector sales account for 23 percent of the total system sales for the State. Again, the ratio varies widely among the utilities. BEPC and LCRA do not sell to commercial customers. SWEPCO sells only 5 percent to commercial customers and that percent is expected to decline over the forecast period. SPS, WTU, and GSU all sell less than 20 percent of their total sales to commercial customers. CPL and TU Electric count on the commercial sector for over a quarter of total sales and EPE, 34 percent. Most reliant on the commercial sector, Austin sells about 50 percent of the MWH system sales to this class of customer.

About a third of all system retail sales in the State are made to the industrial sector. SPS and HL&P exhibit strong dependency upon industrial sales as this category makes up over 50 percent of all system sales for the two companies. GSU relies on industrial customers for 44 percent of its total system sales. At the other end of the spectrum, EPE sells less than 20 percent and COA only 8 percent of total sales to the industrial sector, while LCRA is down to a little over 2 percent, and BEPC, none. Only COA, CPL, and GSU project industrial sales to stay within a point of the current percentage of total system sales, and only HL&P expects an increase in that category. All other utilities project declines in the ratio of industrial customer sales to total system sales over the forecast period.

FIGURE 1.1
TEXAS TOTAL
ANNUAL SALES BY SECTOR (MWH)



SOURCE: TABLE 1.2

TABLE 1.2
Annual Sales by Sector
Texas Total
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	40,538,332	31,707,769	64,155,680	4,264,766	18,887,440	159,553,987
1978	43,941,864	33,734,704	68,497,535	4,549,150	20,938,254	171,661,507
1979	43,726,154	34,058,029	71,666,219	4,554,402	21,783,777	175,788,581
1980	49,763,758	37,086,048	73,009,255	4,938,411	24,128,281	188,925,754
1981	49,051,250	38,924,143	75,749,017	4,723,099	24,696,706	193,144,214
1982	52,530,580	41,446,556	72,841,257	4,989,843	28,193,654	200,001,891
1983	51,560,167	42,230,783	74,746,964	5,041,328	28,852,677	202,431,919
1984	57,480,233	45,598,851	80,543,771	5,474,424	31,332,371	220,429,651
1985	60,676,996	48,634,371	78,083,872	5,910,632	30,544,367	223,850,237
1986	61,024,636	50,163,662	76,148,854	5,963,923	29,446,555	222,747,630
1987	63,088,632	51,058,295	75,458,548	5,537,165	30,357,501	225,500,141
1988	63,918,070	52,960,770	77,197,778	5,734,132	31,279,871	231,090,621
1989	65,345,372	54,278,747	78,004,238	5,879,290	32,489,096	235,996,743
1990	66,817,871	55,662,111	79,849,828	6,023,401	33,294,611	241,647,822
1991	68,603,032	57,189,283	82,031,076	6,174,874	34,202,175	248,200,439
1992	70,533,118	58,754,217	84,052,598	6,322,291	35,256,784	254,919,008
1993	72,446,097	60,396,415	86,495,250	6,485,641	36,428,921	262,252,324
1994	74,420,599	62,113,403	86,860,083	6,645,391	37,631,512	267,670,987
1995	76,476,817	63,859,491	86,353,222	6,823,699	38,889,391	272,402,621
1996	78,582,626	65,728,383	88,327,662	6,979,574	40,212,092	279,830,337
1997	80,769,826	67,593,899	90,386,426	7,168,199	41,656,696	287,575,046

Note: Annual sales figures are prior to demand-side adjustments.

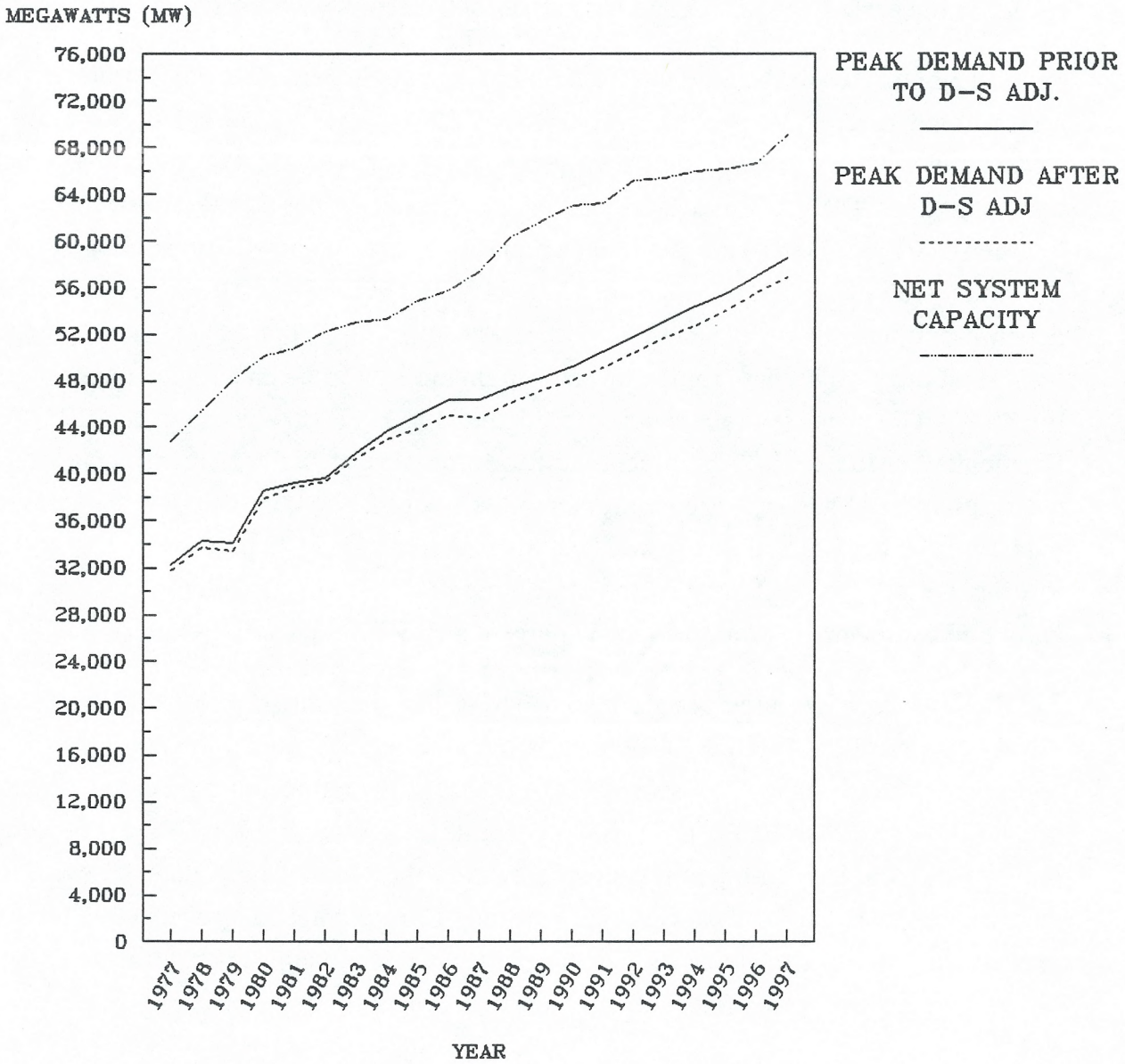
Wholesale customers take a significant percentage of total system sales from only a few utilities. BEPC completely, and LCRA largely, are wholesale suppliers. WTU, SWEPCO, and SPS sell significant percentages of system sales to wholesale customers, at 25 percent, 22 percent, and 17 percent, respectively. These three utilities project increases in their wholesale shares over the forecast period. HL&P experienced reductions in the wholesale sales over the past 10 years, and its sales to wholesale customers declined from 6 percent of sales in 1977 to less than 1 percent in 1987. TNP, now building its first generating plant in Texas, expects to stop purchasing power from HL&P in the early 1990s. COA and CPS do not sell electricity wholesale.

Peak Demand. Across the State of Texas, annual growth in peak demand is projected at a compound rate of 2.3 percent over the 1987-1997 period. Figure 1.2, *Net System Capacity and Peak Demand*, shows three apparent flat spots in the growth of peak demand, after 1978, 1980, and 1986. Even with these slack periods, the overall growth between 1977 and 1987 represents an annual 3.5 percent growth rate, bringing the statewide peak demand after adjustments to 44,849 MW in 1987. This figure reflects a downward adjustment calculated at 1 percent from the sum of individual utility coincident peaks to account for the diversity in the time of occurrence of the peak across the State. The projected rate means peak demand in 1997 will amount to 56,923 MW. Residential customers in 1987 accounted for 42 percent of the coincident peak, while retail commercial and industrial customers were about 22 percent each. Although the industrial and commercial sectors will keep their shares around 22 percent each over the forecast period, the residential sector contribution to the total coincident peak demand before adjustments will drop to about 37 percent in 1997, if expectations hold.

TU Electric shows the largest peak, at 16,680 MW, and that will grow to 21,381 in 1997 if growth follows the projected 2.6 percent compound annual rate. Five utilities expect higher growth rates than TU Electric. COA leads the list, projecting 5.8 percent annual growth through 1997. BEPC projects 4.8 percent, LCRA 4.5 percent, CPS 3.9 percent, and WTU 3.6 percent compound annual growth in the summer peak demand over the next ten years. At the bottom, GSU projects only 1 percent annual growth while HL&P expects the peak to decline by 0.6 percent per year, prior to adjustments for the effects of their aggressive marketing and promotional programs designed to increase peak demand.

Adjustments to Demand. The total measured savings due to interruptible service contracts and conservation and load management practices applied to the peak demand

FIGURE 1.2
TEXAS TOTAL
NET SYSTEM CAPACITY AND PEAK DEMAND



D-S ADJ. is Demand-Side Adjustments.

reportedly amounted to 1,570 MW in 1987. Interruptible service accounts for 81 percent of the MW amount. Interruptible service is more than just a special load management category. It is used to satisfy a portion of the spinning reserve margin by TU Electric and has become a rate design load retention technique for other utilities. Interruptible contracts are projected to decline from 1,268 MW in 1987 to 1,037 MW in 1997.

Load management techniques saved 42 MW from the peak demand in 1987 and the savings are projected to jump to 78 MW in 1988. Beginning in 1989, however, the savings become negative. That is, as HL&P institutes the load growth programs to increase peak demand by 1,284 MW in 1997, the net effect on the State shows savings, due to load management, at a negative 226 MW in 1989 growing to a negative 669 MW in 1997. But, without counting HL&P, utilities report 602 MW of savings through load management in 1997.

Reported savings through the use of strategic conservation amounted to 234 MW in 1987, a drop of 2.8 MW from the 1986 high, although the various reporting methods of the utilities tend to understate these historic conservation achievements. TU Electric, for example, has accumulated nearly 800 MW of conservation and load management reductions but these savings are not reported here. Conservation savings are projected to increase to 1,275 MW in 1997. In that year, TU Electric expects to contribute 775 MW; COA, 246 MW; and LCRA, 127 MW. These three utilities make up 93 percent of the savings through conservation techniques of the entire State, according to projections. Other utilities contribute minor amounts or do not make projections.

The total for the three categories of adjustments indicates savings off the peak demand increasing at an average rate of 1.3 percent per year over the forecast period.

1.2 CAPACITY PLAN

Capacity. In 1987, Texans could rely upon installed generating capacity of 53,934 MW. Projections show this increasing to 66,537 MW in 1997. Table 1.3, *Installed Capacity by Fuel Type*, shows two-thirds of the current capacity fueled by natural gas. Dependence of capacity upon gas falls from nearly 90 percent of total capacity in 1977, to 67 percent in 1987, and is projected to decline further to 58 percent in 1997. Natural gas generating units typically possess the capability to use fuel oil. Although current generation by oil amounts to a negligible 0.2 percent, oil use could increase if natural gas pipeline capacity reaches limits of deliverability. While gas deliverability constraints typically appear in

TABLE 1.3
Installed Capacity by Fuel Type
Texas Total
(MW)

Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	37,667	982	3,050	0	429	0	42,128.1
1978	38,048	2,451	3,800	0	429	0	44,727.7
1979	37,804	3,716	5,300	0	429	0	47,249.4
1980	37,773	5,896	5,300	0	429	0	49,397.6
1981	37,723	5,966	5,845	0	429	0	49,962.5
1982	37,812	6,808	6,236	0	429	0	51,285.5
1983	38,019	7,316	6,236	0	471	0	52,042.2
1984	37,910	7,382	6,236	0	463	0	51,991.1
1985	37,602	7,728	6,582	0	482	0	52,393.9
1986	36,354	7,785	7,431	456	482	0	52,509.0
1987	36,338	8,297	8,198	618	482	0	53,933.9
1988	37,432	8,733	8,198	2,028	488	0	56,879.5
1989	37,388	8,852	8,198	3,275	491	10	58,214.4
1990	37,891	8,887	8,345	4,380	491	10	60,003.8
1991	37,960	8,888	8,492	4,377	491	10	60,218.4
1992	38,142	9,386	8,492	5,484	491	46	62,042.5
1993	38,270	9,386	8,492	5,484	492	46	62,169.6
1994	38,195	9,386	9,390	5,483	492	46	62,992.4
1995	38,041	9,386	10,287	5,484	492	46	63,737.1
1996	38,474	9,386	10,287	5,483	492	46	64,168.4
1997	38,708	10,281	11,681	5,480	340	46	66,536.6

Note: Alternate sources do not include cogeneration.

winter, when most Texas utilities are operating at a lower level of demand, many utilities take advantage of the lower demand to shut down coal and lignite units for maintenance. Thus, utilities retain exposure to the potential winter-weather deliverability problems facing gas pipeline companies. Currently the natural gas industry operates with a surplus of supply and deliverability. However, low gas prices have resulted in reduced drilling activities and deterioration of long-term reserves. CPL and GSU remain over 70 percent dependent upon gas in their capacity throughout the forecast period. Although some utilities will add gas-fueled generation over the forecast period--TU, for example, plans a net increase in gas-fueled capacity of more than 900 MW--no utility plans to increase reliance on gas as a percentage of installed capacity. Only BEPC remains totally reliant on gas in its installed capacity.

Coal-fired generation capacity increased from 2 percent of total capacity in 1977 to 15 percent in 1987 and, if projections hold, will be 15 percent in 1997. Similarly, lignite-powered capacity grew from 7 percent of the total in 1977 to 15 percent in 1987 and will be 17 percent in 1997. SWEPCO placed the Pirkey and Dolet Hills lignite stations on line in 1985 and 1986, providing 816-MW capacity from lignite. TNP is constructing the lignite-fueled Robertson units and plans to finish the first 150-MW unit in 1990. TU Electric plans to build the two Twin Oak lignite units for 1,500-MW capacity by 1995. Lignite-fueled capacity reportedly will increase from 8,198 MW in 1987 to 11,681 MW in 1997. Coal-fueled capacity reportedly will grow to 10,281 MW in 1997 from 8,297 MW in 1987.

GSU completed the nuclear-powered River Bend plant in Louisiana in 1986, and EPE obtained power from the nuclear-powered Palo Verde station in Arizona in that year. Combined, the two utilities added 456 MW of nuclear capacity allocated to customers in Texas in 1986, and that increased to 618 MW in 1987.

HL&P, CPL, CPS, and COA joined together to build the South Texas Project, now in commercial operation. The utilities project Unit Two availability as of December 1989. Each unit is designed to supply 1,250 MW of capacity.

With a 94-percent share of the Comanche Peak station, TU Electric projects adding 1,081 MW of nuclear capacity before the peak of 1990 and another 1,081 in 1992. Each unit is designed to provide 1,150-MW capacity. The other partners are BEPC with a 3.8 percent share and Tex-La Electric Cooperative of Texas with a 2.2 percent share. TU acquired the 6.2 percent interest held by the Texas Municipal Power Authority and has

applied to amend its certificate to acquire the BEPC share. Texas total nuclear capacity projections show growth from 618 MW in 1987 to 5,480 in 1997, or from about 1 percent of total capacity to about 8 percent.

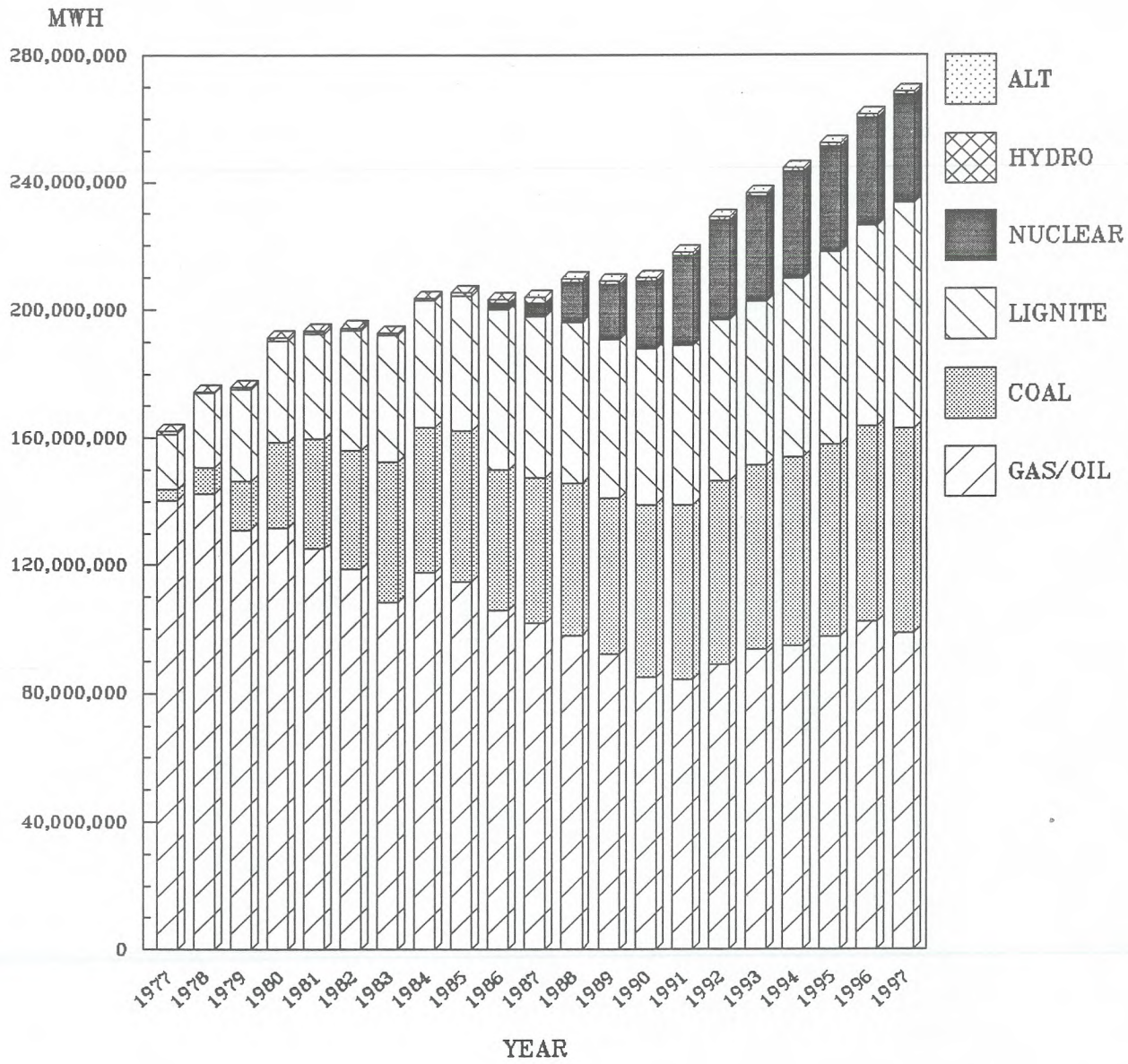
The only renewable (not including hydroelectric generation) or other alternative source of energy owned by a utility currently is the 0.3-MW solar photovoltaic plant in Austin. Plans by COA, CPS, and Lubbock Power and Light to build solid-waste-fired generation stations and the COA agreement to purchase manure-derived power from the Valley View Energy Corporation in the Panhandle would bring the State total to 64.3 MW in 1992. COA has already decided to postpone its waste-to-energy plant, however.

Cogeneration is a significant source of electric energy in Texas. Capacity in 1987 totaled 5,178 MW, with an additional 495 MW under construction. Although the growth of cogeneration is slowing, cogenerators do expect to provide the State over 5,800 MW capacity by mid-1989. Approximately 53 percent of the operational capacity is under firm contract. About 95 percent of the cogeneration in Texas is fueled by natural gas and produced by gas turbines. Texas ranks first among all states in industrial, on-site electrical generation. Major cogenerators include various petroleum and petrochemical firms on the Gulf Coast in the HL&P, CPL, and TNP service areas. The seven biggest projects contribute over 75 percent of the total amount cogenerated. Dow Chemical Company, with 1,300 MW of capacity, would be the thirteenth largest utility in Texas, were it a utility rather than a qualifying facility.

With so much cogeneration concentrated around Houston and with the current flat market for electricity in that area, the need exists to wheel the power out of the area. Utilities must wheel power from the qualifying facility to another utility if requested and if the wheeling utility has the transmission capacity at that time. Wheeling services provided to cogenerators now total over 1,800 MW. The increasing utilization of transmission facilities for wheeling will continue to be a significant reliability concern within ERCOT. During 1986, 13 instances of interrupted wheeling transactions occurred due to insufficient transmission capacity.

Comparing Table 1.3 with Figure 1.3, *Net Generation By Fuel Type*, shows the contrast between capacity and actual generation. While gas makes up two-thirds of the capacity, just under half of the energy generated by the utilities used gas for fuel. Projections indicate the percentage in 1997 at 37 percent. With coal and lignite capacities each about 15 percent of the total installed capacity, actual net generation amounted to 22

FIGURE 1.3
NET GENERATION BY FUEL TYPE (MWH)
TEXAS TOTAL



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

TABLE 1.4
Net System Capacity and Reserve Margins
Texas Total
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	32,197	31,728	42,128	1,791	1,095	42,825	35.0
1978	34,334	33,684	44,728	1,918	1,252	45,393	34.8
1979	34,088	33,376	47,249	2,135	1,301	48,084	44.1
1980	38,551	37,851	49,398	2,772	2,062	50,107	32.4
1981	39,283	38,895	49,963	3,320	2,512	50,770	30.5
1982	39,624	39,355	51,286	4,253	3,297	52,242	32.7
1983	41,773	41,270	52,042	4,216	3,245	53,013	28.5
1984	43,693	43,005	51,991	4,118	2,798	53,311	24.0
1985	44,996	43,890	52,394	5,580	3,141	54,833	24.9
1986	46,352	45,075	52,509	6,062	2,809	55,762	23.7
1987	46,419	44,849	53,934	6,240	2,747	57,428	28.0
1988	47,479	46,069	56,880	5,587	2,138	60,328	31.0
1989	48,250	47,150	58,214	6,075	2,615	61,674	30.8
1990	49,249	48,078	60,004	5,647	2,584	63,067	31.2
1991	50,438	49,148	60,218	5,773	2,718	63,273	28.7
1992	51,790	50,428	62,042	5,180	1,998	65,224	29.3
1993	53,167	51,694	62,170	5,555	2,336	65,389	26.5
1994	54,350	52,762	62,992	5,252	2,215	66,030	25.1
1995	55,501	54,044	63,737	4,566	2,070	66,233	22.6
1996	57,011	55,558	64,168	4,918	2,431	66,655	20.0
1997	58,551	56,923	66,537	5,065	2,488	69,113	21.4

Note: Peak demand columns are adjusted downward by 1 percent to reflect load diversity among Texas utilities.

The difference between Purchases and Sales is due to cogeneration and off-system sales not Reported by sellers

percent and 25 percent of the total, respectively. Nuclear power is expected to grow from providing 2 percent of the generated energy in 1987 to 13 percent in 1997. Overall, 203,516,962 MWH were generated by the utilities in 1987, and, at the projected compound rate of 2.8 percent per year, 267,535,324 MWH will be generated by utilities in 1997.

Net system capacity is the sum of net firm contract sales and purchases of capacity and the installed capacity. Shown in Table 1.4, *Net System Capacity and Reserve Margins*, purchases from outside the utilities' systems regularly exceed sales off the systems. Purchases may involve non-Texas utilities for those not in the ERCOT network, or may involve independent small power producers and cogenerators in or out of Texas. Purchases of capacity grew at an average annual compound rate of 13.3 percent from 1977 to reach 6,240 MW in 1987. Total firm purchases of capacity, net of off-system sales, amounted to 3,493 MW in 1987. Total off-system sales amounted to 2,747 MW capacity in 1987. The utilities project a drop in purchased capacity to 5,065 MW in 1997.

Projections that purchases will fall may or may not accurately reflect the volume of purchases that actually will occur. Contracts may become more or less attractive in the future as utilities examine their costs to operate and compare the price other generators are willing to charge. Many factors bear on the decisions. According to projections, net system capacity for the State will average 1.9 percent compound growth per year through 1997.

Planned and Potential Changes in Installed Capacity. The utilities operating in Texas are planning to add about 11,430 MW of new capacity to meet the growth in demand and make up for the retirements of old units over the forecast horizon. Capacity additions and retirements between 1988 and 1997 as reported by the utilities are summarized in Table 1.5. Furthermore, some existing and planned sites are capable of accomodating additional units to meet future demand beyond 1997. Some of these potential sites are presented in Table 1.6.

Reserve Margins. Reserve margin is defined as capacity beyond that needed to meet the peak demand as a percentage of corresponding peak demand. Statewide, the reserve margin in 1987 amounted to 29.8 percent. Such additional capacity must exist for security of the system. The social costs of blackouts or brownouts are difficult to measure, but potentially catastrophic. Security of supply is one of the characteristics that helps make electricity such a useful form of energy. The necessary margin is a matter of

TABLE 1.5
Planned Capacity Additions and Retirements
1988 - 1997

Utility	Additions	Retirements	MW	Fuel	Total Installed Cost Including AFUDC
1988					
EPE	Palo Verde 3		200	Uranium	N/A
GSU		Nelson 1, 2	(200)	Gas	
BEPC		Poage 1, 2	(24)	Gas	
TU	Permian Basin CT 1-3		195	Gas	$65,109
HL&P + others	STNP 1		1,250	Uranium	$2,986,482,600
LCRA	Fayette 3		405	Coal	$544,000,000
GBRA	Canyon		6.2	Water	N/A
1989					
SRG&T	Big Cajun #2 1		38	Coal	N/A
LP&L	Waste Recovery 1		10	Refuse	N/A
HL&P + others	STNP 2		1,250	Uranium	$1,990,988,400
TU + others	Comanche Peak 1		1,150	Uranium	$4,019,220,000
LP&L		Plant 2 4	(11.5)	Gas	
1990					
LP&L	TECH 1		50	Gas	N/A
TU	DeCordova CT 1-4		260	Gas	$110,563,000
TU	Permian Basin CT 4-5		130	Gas	$50,848,000
COA	Resource Recovery 1		20	Refuse	$12,750,000
TNP	TNP One 1		148	Lignite	$253,517,000
TU + others	Comanche Peak 2		1,150	Uranium	$2,679,480,000
1991					
TNP	TNP One 2		148	Lignite	$230,609,000
BRN		Diesel Plant 1	(2)	Diesel	
COA		Seaholm 5, 6	(36)	Gas	
1992					
CPS	Calaveras 5		498	Coal	N/A
CPS	MSW 1		36	Refuse	N/A
1993					
SWEPCO		Lone Star 2, 3, 4	(40)	Gas	
TU	Comb. Turbine 1		130	Gas	$62,525,000

(continued)

TABLE 1.5 (continued)
Planned Capacity Additions and Retirements
1988 - 1997

Utility	Additions	Retirements	MW	Fuel	Total Installed Cost Including AFUDC
1994					
TU	Twin Oak 1		750	Lignite	$1,329,604,000
TNP	TNP One 3		148	Lignite	$243,171,000
TU		Dallas 3, 9	(145)	Gas	
BRN		Diesel Plant 4	(3)	Diesel	
1995					
TU		Mountain Creek 6	(115)	Gas	
TU	Twin Oak 2		750	Lignite	$864,815,000
TNP	TNP One 4		148	Lignite	$246,450,00
TU		Handley 1	(45)	Gas	
TU		Parkdale 2	(115)	Gas	
MEC	Pearsall CT		79	Gas	$34,018,000
COA		Seaholm 7, 8	(33)	Gas	
CPL		La Palma 7	(43)	Gas	
1996					
TU		Handley 2	(80)	Gas	
TU	Comb. Turbine 2		390	Gas	$211,048,000
HL&P	Malakoff 1		645	Lignite	$1,302,000,000
1997					
COA	Combined Cycle 1		200	Gas	N/A
TU	Forest Grove 1		750	Lignite	$1,245,965,000
BRN		Diesel Plant 5	(4)	Diesel	
TU		Morgan Creek 2,3	(66)	Gas	
WTU		Abilene 3, 4	(26)	Gas	
WTU		Concho 3	(15)	Gas	
WTU		Fort Stockton 2	(5)	Gas	
WTU		Lake Pauline 1	(19)	Gas	
CPS	Calaveras 6		498	Coal	N/A

Note: GBRA represents Guadalupe-Blanco River Authority; SRG&T, Sam Rayburn Generation and Transmission; LP&L, Lubbock Lighting and Power; BRN, Brownfield Municipal Power and Light; and MEC, Medina Electric Cooperative. SRG&T's addition is a purchase of an existing unit of the Cajun Electric Power Cooperative. The COA 1990 addition was postponed indefinitely by the city council in July 1988. The MEC 1995 addition is a conversion of a steam turbine to a combined cycle plant. Total Installed Cost Including AFUDC data is taken directly from Request 17 to the Load and Capcity Resource Forecast. All cost data is the utilities estimate as of December 31, 1987.

TABLE 1.6
Potential Capacity Additions at Existing Sites

Utility	Plant Site	MW	Fuel
TU	Martin Lake	750	Lignite
	Forest Grove	750	Lignite
	Small units at various sites	490	Gas
HL&P	South Texas 3 & 4	2,500	Uranium
GSU	Small units at various sites	1,400	Gas
	Nelson	550	Coal
	River Bend & Blue Hills	4,700	Uranium
SWEPCO	Pirkey	640	Lignite
	Dolet Hills	640	Lignite
CPL	Coleto Creek 2	650	Coal
	Small units at various sites	1,550	Gas
EPE	Palo Verde 4 & 5	2,540	Uranium
WTU	Oklaunion 2 & 3	1,440	Coal
BEPC	RW Miller 4, 5, 6, & 7	700	Gas

judgment. Clearly, too great a margin wastes social resources and the customer pays higher-than-necessary electric bills. A suitable margin provides reliability of supply by allowing for planned or forced outages of generating equipment, for equipment deratings due to various causes, and for the differences between actual demands and those forecast. The necessary margin for one utility may not be the same as for another but differs to reflect the different circumstances, such as the duration of the peak load season and the outage rates for the different sizes and types of generation. As seen in Table 1.4, reserve margins generally fell to a low in 1986, are expected to rise through 1990, and will fall again through the 1990s, if utility projections are realized. Reserve margins for ERCOT fell below the statewide average of 31.4 percent in 1982. In 1987, ERCOT held a margin of 24.5 percent, up from a 1986 low of 19.7 percent. ERCOT will not exceed the statewide average until 1995, if projections of the 22.2 percent reserve are met.

Using a capacity margin concept, where the amount by which the planned capacity resources exceed the peak demand is divided by the total planned capacity resources, the National Electric Reliability Council (NERC) reports the average capacity margin in the U.S. in 1986 was 26 percent. The following projection by NERC shows the regional capacity margins:

Region	Summer 1987	Summer 1996
ECAR	26	21
ERCOT	20	17
MAAC	24	21
MAIN	26	18
MAPP	27	22
NPCC	24	21
SERC	24	20
SPP	29	17
WSCC	32	25
NERC (US)	26	21

The few capacity additions planned by Texas utilities through 1995 will result in smaller reserve margins. This may reduce the flexibility for utilities to meet situations that differ from those expected. ERCOT has issued guidelines for the minimum requirements for integration of new generating plants into the system and improving communication within the system.

The issues of concern to the ERCOT member systems include the role of cogeneration, the completion of generation units on schedule, the growing lead time for establishing

new generating capacity, and development of transmission systems to accommodate the increasing volume of economy purchases and sales as well as bulk power transfers over long distances. Over the forecast period, projected reserve margins with expected plant additions meet the requirements adopted by the region, and expected reliability appears adequate.

This concludes the statewide summary of demand forecasts and capacity plans filed by the Texas utilities. The thirteen largest utilities, collectively selling 96 percent of the electric power in the State, are analyzed in detail in the following 13 chapters, while the final chapter summarizes information filed by 16 other utilities. Appendix A describes and lists demand-side management programs reported in the energy efficiency plans filed by the utilities with the PUCT. Appendix B provides an inventory of existing generation plant owned by utilities in Texas.

CHAPTER TWO

TU ELECTRIC COMPANY

TU Electric Company is a public utility engaged in the generation, purchase, transmission, and distribution of electricity in 91 counties of Texas, including the Dallas-Fort Worth area. The Company operates as a member of the Electric Reliability Council of Texas.

TU Electric is a subsidiary of Texas Utilities Electric Company, an investor-owned company. Its utility operating divisions are Dallas Power and Light, Texas Power and Light, and Texas Electric Service Company. TU Electric's 1987 revenues totaled $4,079,301,000, while total assets as of December 31, 1987 were valued at $12,938,655,000. The Company's capital structure as of that date was comprised of 45.5 percent common equity, 10.8 percent preferred stock, and 43.7 percent long-term debt.

TU Electric is a summer-peaking utility and reported actual 1987 peak demand after adjustments as 16,567 MW, its highest to date. The utility sold 77,665,792 MWH in 1987. Installed capacity totaled 17,804 MW. Fifty percent of the net generation in 1987 was fueled by gas, 49.8 percent by lignite, and 0.2 percent by oil.

2.1 DEMAND FORECAST

Forecasting Methodology. TU Electric employs an econometric model in formulating its sales forecasts. The relationships between electricity consumption and a variety of influential factors, including weather, economic and demographic changes, appliance saturations, and electricity and natural gas prices, were determined statistically from actual historical data. The TU model uses forecasts of these several factors to estimate levels of future electricity consumption.

TU regards the number of jobs added to the service area economy as one of the most important factors in its sales models. The Company considers employment statistics to be the most accurate and up-to-date measure of economic activity at the substate level. More importantly, the utility maintains that over the long term, employment opportunities in the service area determine much of the in- and out-migration, income, and other major economic/demographic measures for the service area. The TU service

area historically has demonstrated cyclical job growth, experiencing a significant slowing of growth during the 1974-75 recession and an employment decrease during both the 1982-83 recession and 1986-87 downturn in the Texas economy. However, the overall trend through the 1970s and 1980s has been one of vigorous growth. TU has developed a number of alternative demand scenarios based on different employment projections.

TU forecasts peak demand using an end-use model, the Hourly Electric Load Model (HELM), to show the probable hourly distribution of annual sales forecasts. HELM produces hourly load curve forecasts by combining annual sales forecasts in MWH with input load shapes for each component end-use in the system. Aggregate class or system load shapes are built up from these individual end uses. End-use definitions are user-supplied and dependent on load shape data availability. Conservation, load management, and interruptible loads MW and MWH are subtracted from the sales and peak demand forecast to obtain adjusted sales and peak demand.

Number of Customers. As shown in Table 2.1, *Number of Customers by Sector*, TU Electric provided electric service to 2,006,725 residential customers in 1987. The historical data for the period from 1977 through 1987 show an average annual compound growth rate of 3.8 percent for the residential class of customers. Growth at a rate of nearly 2.5 percent annually is projected to continue into 1997. Commercial customers totaled 219,502 in 1987. While a 3.9 percent annual increase occurred over the previous 10 years, the projected rate of increase drops by half, to slightly less than 1.8 percent per year for the next 10 years. Currently, TU serves 23,968 industrial customers. The annual rate of growth is expected to decline for the number of industrial customers, from 3.5 percent over the historical period to 2.8 percent through 1997.

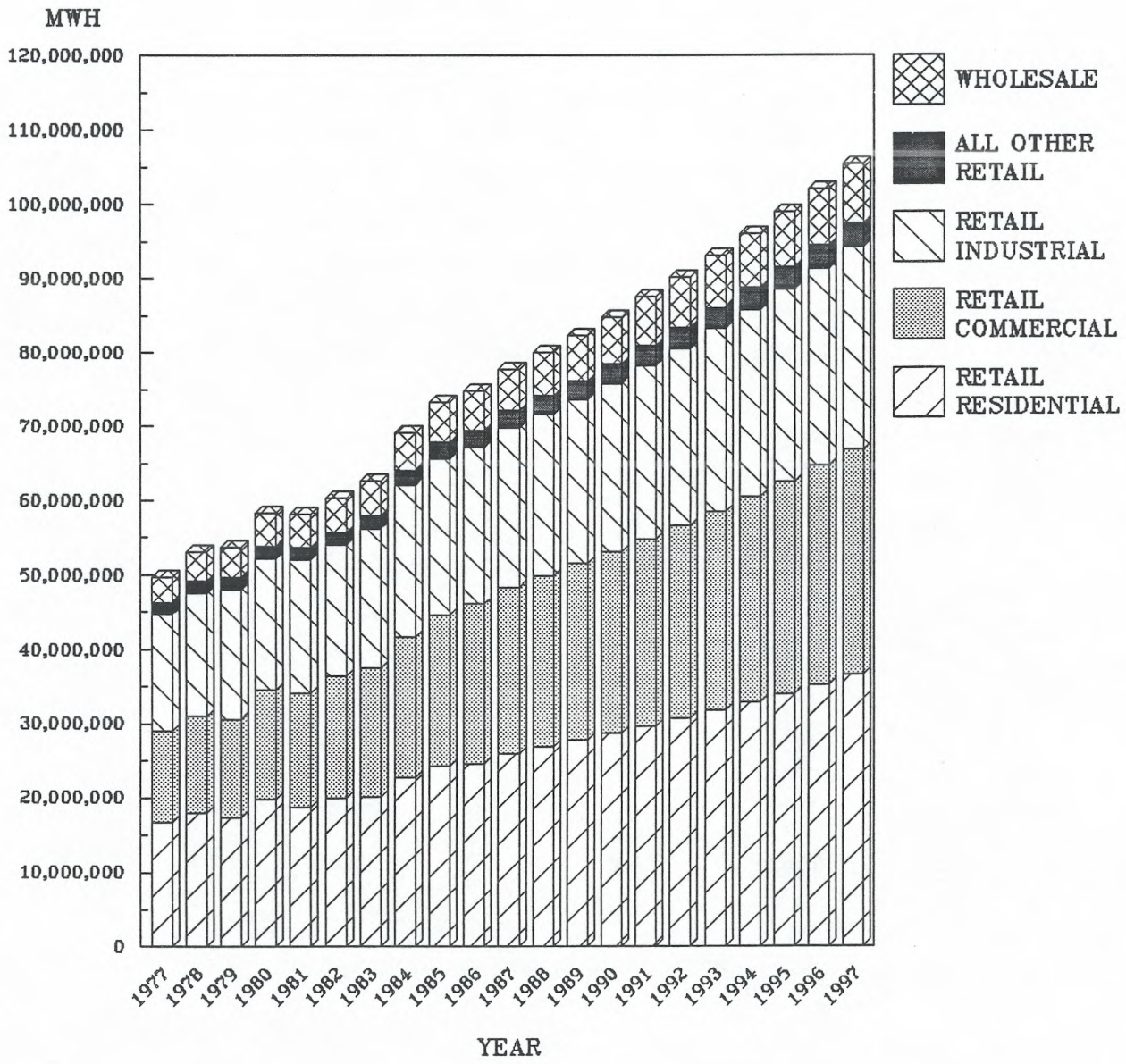
Total Sales. As indicated in Figure 2.1 and Table 2.2, *Annual Sales by Sector*, 1987 sales to the residential sector amounted to 26,024,673 MWH. Sales to residential customers in that year comprised 33.5 percent of total system sales, the same percentage as in 1977. The Company projects that the residential sector will demonstrate the highest annual growth at 3.5 percent. As a result, sales to this sector will grow to 34.7 percent of total sales by 1997 and amount to 36,536,196 MWH. TU projects sales within the commercial sector to increase from 22,348,930 MWH in 1987 at the rate of about 3 percent per annum through 1997, down from the over 6 percent per year average seen during the period from 1977 through 1987. Industrial sales have grown at an average compound annual rate of 3.1 percent since 1977 to a total of 21,324,370 MWH in 1987. Sales to

TABLE 2.1
Number of customer by Sector
TU Electric Company

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	1,379,547	150,435	16,961	11,177	57
1978	1,432,767	156,665	17,602	11,300	57
1979	1,491,468	162,622	18,317	11,455	56
1980	1,547,912	167,280	19,193	11,445	61
1981	1,603,456	174,650	20,183	10,376	59
1982	1,650,440	182,227	21,145	10,111	57
1983	1,706,920	193,914	21,959	10,195	57
1984	1,801,146	204,763	23,446	10,258	61
1985	1,901,944	212,164	23,985	12,230	59
1986	1,970,405	216,948	24,086	12,875	56
1987	2,006,725	219,502	23,968	13,245	58
1988	2,052,753	224,934	24,492	13,207	59
1989	2,097,847	228,800	24,990	13,410	59
1990	2,146,613	232,735	25,566	13,617	59
1991	2,197,736	236,741	26,221	13,828	59
1992	2,251,359	240,819	26,952	14,043	59
1993	2,307,637	244,970	27,750	14,262	59
1994	2,366,736	249,196	28,610	14,484	59
1995	2,428,836	253,499	29,530	14,710	59
1996	2,494,128	257,877	30,506	14,940	59
1997	2,562,821	262,335	31,534	15,175	59

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 2.1
TU ELECTRIC COMPANY
ANNUAL SALES BY SECTOR (MWH)



SOURCE: TABLE 2.2

TABLE 2.2
Annual Sales by Sector
TU Electric Company
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	16,642,382	12,347,755	15,678,254	1,565,518	3,445,380	49,679,289
1978	17,943,224	13,117,202	16,469,636	1,728,056	3,869,018	53,127,136
1979	17,394,404	13,264,435	17,275,859	1,669,727	4,155,813	53,760,238
1980	19,844,409	14,683,104	17,581,265	1,796,988	4,454,706	58,360,472
1981	18,676,240	15,383,162	17,992,261	1,692,108	4,372,626	58,116,397
1982	19,945,086	16,475,251	17,526,411	1,730,272	4,612,885	60,289,905
1983	20,162,506	17,366,562	18,690,077	1,790,473	4,670,438	62,680,056
1984	22,693,288	19,026,268	20,343,557	1,920,422	5,127,040	69,110,575
1985	24,300,789	20,349,335	20,921,532	2,324,782	5,396,133	73,292,571
1986	24,604,110	21,453,433	21,013,279	2,385,169	5,398,769	74,854,760
1987	26,024,673	22,348,930	21,324,370	2,440,388	5,527,431	77,665,792
1988	26,950,465	22,898,327	21,733,431	2,521,995	5,946,793	80,051,011
1989	27,830,690	23,624,913	22,167,751	2,594,557	6,087,910	82,305,821
1990	28,684,468	24,348,474	22,745,381	2,666,958	6,347,353	84,792,634
1991	29,658,380	25,096,818	23,473,321	2,741,781	6,601,676	87,571,976
1992	30,729,963	25,874,742	23,920,272	2,819,479	6,790,184	90,134,640
1993	31,777,629	26,683,758	24,733,571	2,900,189	6,999,150	93,094,297
1994	32,882,183	27,528,633	25,373,844	2,984,365	7,213,235	95,982,260
1995	34,045,244	28,410,626	26,022,078	3,072,121	7,432,110	98,982,179
1996	35,258,769	29,331,920	26,681,642	3,163,665	7,664,480	102,100,476
1997	36,536,196	30,294,453	27,315,548	3,259,181	7,969,420	105,374,798

Note: Annual sales figures are prior to demand-side adjustments.

wholesale customers, at 5,527,431 MWH, comprised 7 percent of total system sales in 1987 and are expected to retain this share of the total for the next 10 years.

Total system sales amounted to 77,665,792 MWH in 1987 after growing at a compound rate of about 4.6 percent annually for 10 years. Based on Company projections, growth over the next 10 years will drop to 3.1 percent annually, with an estimated total system sales in 1997 of 105,374,798 MWH.

Another component to TU's sales are the non-firm, off-system sales. This category displays no constant pattern, with sales ranging from 23 MWH (1977) to 365,202 MWH (1979). In 1987, 310,239 MWH were sold off-system, 0.4 percent of all electricity sold by TU that year. Beginning in 1988, the utility projects sales of 177,000 MWH per year for three years and then 185,000 per year through 1997. Adding the total system and off-system shows that TU sold 77,976,031 MWH in 1987, an increase of 57 percent over total combined system and off-system sales in 1977.

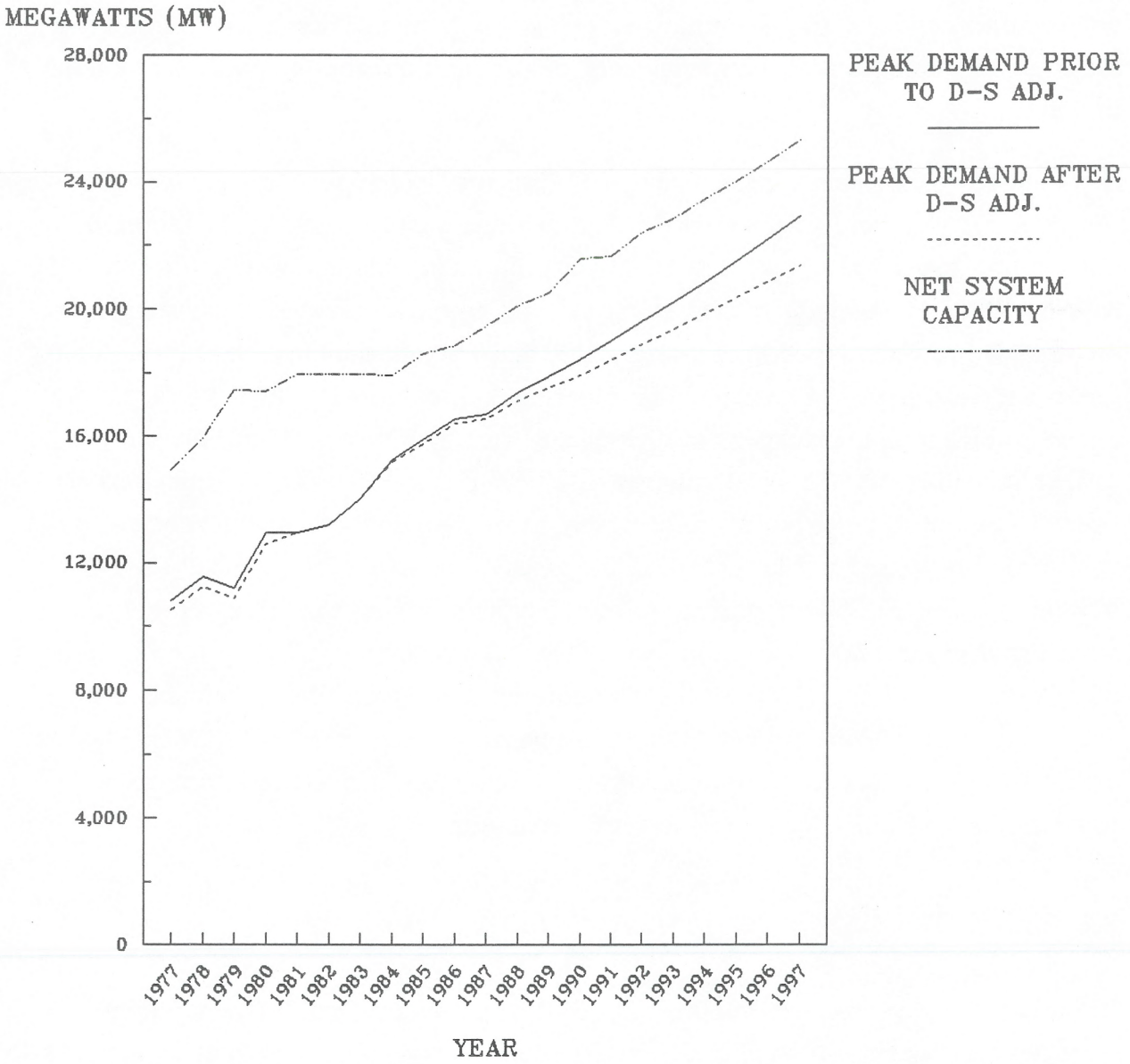
Peak Demand. Over the period from 1977 through 1987, TU experienced 4.6 percent annual growth in peak demand. As shown in Figure 2.2, *Net System Capacity and Peak Demand*, peak demand rose from 10,525 MW in 1977 to 16,567 MW in 1987. TU projects 1988 peak demand will increase 3.4 percent over 1987, and over the next 10 years at a growth rate of 2.6 percent per year.

TU reports neither current nor historical data on the coincident peak load by sector, although projections are made. If these hold, demand of the residential sector will account for 46 percent of the system coincident peak load in 1997, the commercial sector 25 percent, and the industrial sector, 16 percent.

TU reports neither current nor historical data for the non-coincident peak load by sector. However, in 1988, TU expects the residential sector to demonstrate the highest non-coincident peak, a demand of 8,128 MW of electricity.

Demand Side Adjustments. TU Electric states an energy efficiency goal to lower the peak load through conservation and load management programs. The Company encourages residential customers to install high-efficiency air conditioning and advises the replacement of resistance heating by heat pump equipment. TU also actively promotes the structural energy efficiency of new and existing homes and multifamily structures. On-site energy audits provide opportunities for customers to learn more about residential energy efficiency.

FIGURE 2.2
TU ELECTRIC COMPANY
NET SYSTEM CAPACITY AND PEAK DEMAND



D-S ADJ is Demand-Side Adjustments.

For both residential and non-residential customers, TU offers incentives to install water heating systems utilizing heat pump, heat recovery, and solar technologies. As an additional possibility, the use of ground-coupled-heat pump equipment is encouraged. To reduce commercial customers' on-peak demand, TU proposes thermal storage as an alternative technology for air conditioning. Additionally, TU encourages efficient commercial lighting and provides optional interruptible service and time-of-day rates for interested commercial and industrial customers.

TU provides customers with information on ways to reduce energy consumption through publications, seminars, and presentations for various groups of customers. In addition, the Company updates architects, engineers, dealers and distributors on current energy topics.

In measured adjustments to peak demand, TU lists only interruptible service for the past 10 years, ranging from zero to 379 MW in any one year. In 1987, TU reported an interruptible load of 113 MW. The Company projects interruptible load to grow to 305 MW by 1997. Historically, savings resulting from conservation and load management are assumed to be included in the historical data, so no adjustments are reported in its Load Forecast filing. However, TU reported approximately 800 MW of historic conservation and load management savings in its Energy Efficiency Plan. TU projects a further reduction of 71 MW of capacity in 1988. From this point, the utility expects conservation savings to increase quite rapidly, more than doubling in 1989 and growing to 775 MW by 1997. Similarly, load management techniques are expected to save 10 MW in capacity in 1988 and then grow at about 50 MW per year through the forecast period saving 455 MW capacity in 1997. The total savings in capacity for the three categories, shown in Figure 2.2 as the difference between Peak Demand Before Adjustments and Peak Demand After Adjustments, increase from 113 MW in 1987 to 1,535 in 1997. Projected adjustments for 1997 would result in a 6.7 percent reduction in the peak demand which is expected to exist in that year.

2.2 CAPACITY PLAN

Efficiency Improvements to Supply. TU Electric states that existing generation units were designed and constructed in a coordinated manner whereby individual components and systems are sized to complement other components and systems. To increase the amount of net capacity available from any existing unit would require replacement of a

large portion of the existing equipment due to the interdependent relationships among the various components and systems. The Company's productivity improvement programs and design retrofit programs are intended to maintain, or recover and maintain, the maximum net capability of the generating units and to improve their availability or efficiency. The Company is instituting the Life Operating Management Plan to extend service lives of existing generating units through refurbishment and improvement in unit efficiencies.

Transmission and distribution facilities are planned and designed to deliver power and energy from the Company's various sources of supply to its customers' loads in the most economical way practicable while maintaining adequate system reliability. Planned equipment maintenance retains the efficiency of existing equipment.

Installed Capacity. In 1987 TU Electric possessed 61 generating units with a total capacity of 17,804 MW (See Table 2.3, *Installed Capacity by Fuel Type*) Gas plants make up 67 percent of this capacity, and lignite-fueled stations, 32.8 percent. As of December 31, 1987, TU Electric's production plant carried an acquisition cost of approximately $3 billion with a net book value of $1.8 billion.

Net System Capacity. Installed capacity plus the net of firm off-system sales and purchases yields net system capacity. As shown on Table 2.4, *Net System Capacity and Reserve Margins*, firm purchases from cogenerators and other small power producers of 1,661 MW, no firm sales, and installed capacity of 17,804 MW gives the net system capacity of 19,465 MW in 1987. The Company plans no firm off-system sales for the forecast period. Firm purchases made up about 8.5 percent of net system capacity in 1987 and will maintain that percentage in 1997. Suppliers of capacity include Alcoa, Tex-La Electric Cooperative, Lyondell, Applied Energy Services, Falcon Seaboard, Enron, Wichita Falls, Texas Gulf, Encogen One Partners, Tenaska, Dow, Cleburne, Rayburn Country, and Bio-Energy Partners.

Net Generation. Figure 2.3, *Net Generation by Fuel Type*, clearly shows that gas has been the major fuel used by TU. For the year 1987, gas was used to generate 50 percent of the power supplied, lignite 49.8 percent, and oil, 0.2 percent. This differs significantly from the generation mix in 1977, which shows gas supplied 66 percent, oil 1 percent, and lignite 33 percent. TU is reducing its reliance on gas and oil and increasing generation from lignite, although most of TU's cogeneration suppliers rely on gas-fired generation.

TABLE 2.3
Installed Capacity by Fuel Type
TU Electric Company
(MW)

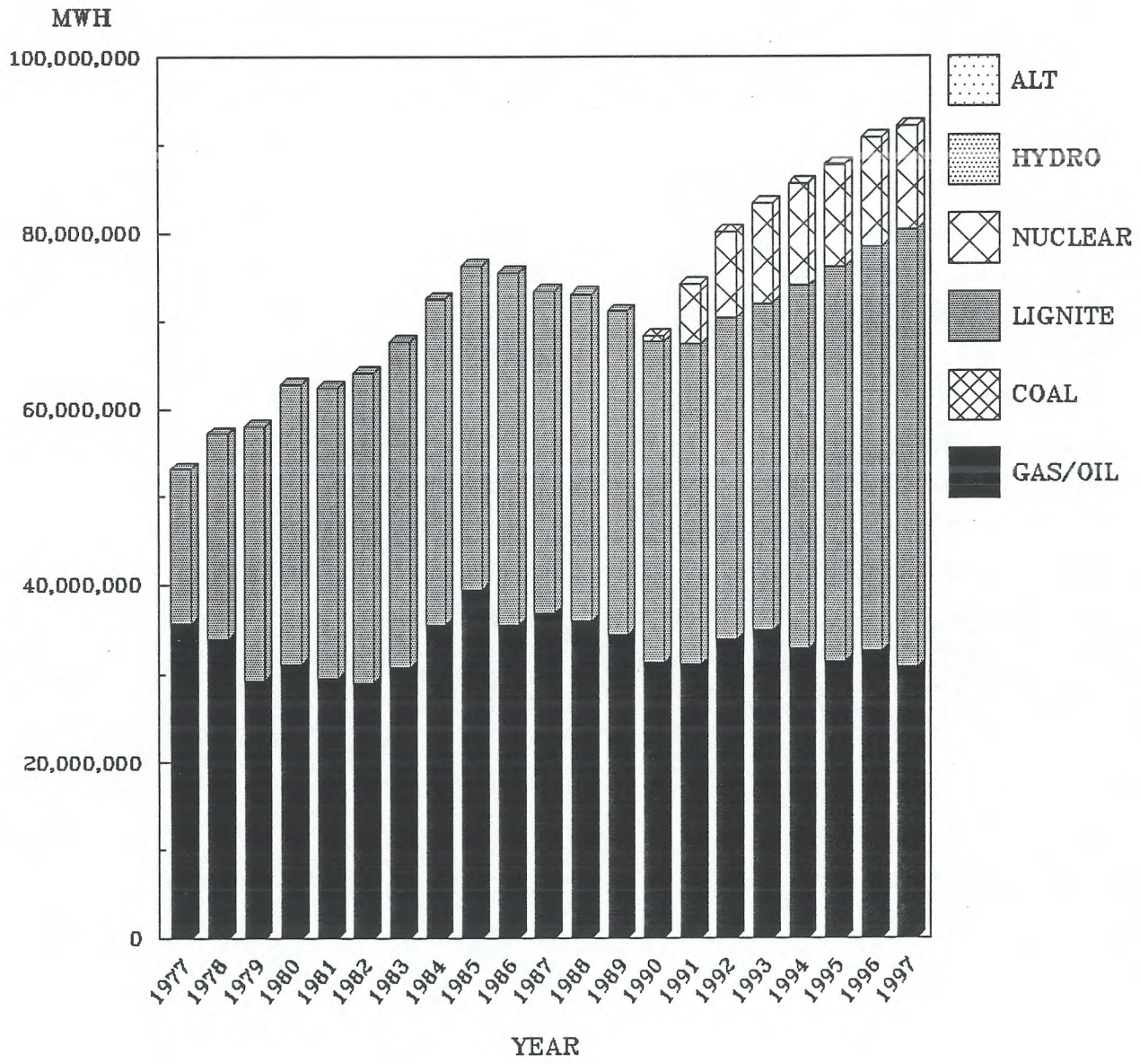
Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	11,774	0	3,050	0	0	0	14,824
1978	12,037	0	3,800	0	0	0	15,837
1979	12,037	0	5,300	0	0	0	17,337
1980	12,017	0	5,300	0	0	0	17,317
1981	12,017	0	5,845	0	0	0	17,862
1982	12,017	0	5,845	0	0	0	17,862
1983	12,017	0	5,845	0	0	0	17,862
1984	11,965	0	5,845	0	0	0	17,810
1985	11,959	0	5,845	0	0	0	17,804
1986	11,959	0	5,845	0	0	0	17,804
1987	11,959	0	5,845	0	0	0	17,804
1988	12,544	0	5,845	0	0	0	18,389
1989	12,544	0	5,845	0	0	0	18,389
1990	12,934	0	5,845	1,081	0	0	19,860
1991	12,934	0	5,845	1,081	0	0	19,860
1992	12,934	0	5,845	2,162	0	0	20,941
1993	13,064	0	5,845	2,162	0	0	21,071
1994	12,804	0	6,595	2,162	0	0	21,561
1995	12,644	0	7,345	2,162	0	0	22,151
1996	12,954	0	7,345	2,162	0	0	22,461
1997	12,888	0	8,095	2,162	0	0	23,145

Note: Alternate sources do not include cogeneration.

TABLE 2.4
Net System Capacity and Reserve Margins
TU Electric Company
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	10,798.0	10,525.0	14,824.0	95.0	0.0	14,919.0	41.7
1978	11,548.0	11,232.0	15,837.0	95.0	0.0	15,932.0	41.8
1979	11,202.0	10,880.0	17,337.0	95.0	0.0	17,432.0	60.2
1980	12,970.0	12,591.0	17,317.0	95.0	0.0	17,412.0	38.3
1981	12,970.0	12,970.0	17,862.0	95.0	0.0	17,957.0	38.5
1982	13,204.0	13,204.0	17,862.0	95.0	0.0	17,957.0	36.0
1983	14,029.0	14,029.0	17,862.0	95.0	0.0	17,957.0	28.0
1984	15,265.0	15,189.0	17,810.0	95.0	0.0	17,905.0	17.9
1985	15,898.0	15,769.0	17,804.0	810.0	0.0	18,614.0	18.0
1986	16,537.0	16,407.0	17,804.0	1,050.0	0.0	18,854.0	14.9
1987	16,680.0	16,567.0	17,804.0	1,661.0	0.0	19,465.0	17.5
1988	17,378.0	17,127.0	18,389.0	1,717.0	0.0	20,106.0	17.4
1989	17,877.0	17,519.0	18,389.0	2,123.0	0.0	20,512.0	17.1
1990	18,405.0	17,932.0	19,860.0	1,710.0	0.0	21,570.0	20.3
1991	18,989.0	18,379.0	19,860.0	1,810.0	0.0	21,670.0	17.9
1992	19,599.0	18,887.0	20,941.0	1,485.0	0.0	22,426.0	18.7
1993	20,207.0	19,369.0	21,071.0	1,785.0	0.0	22,856.0	18.0
1994	20,841.0	19,864.0	21,561.0	1,885.0	0.0	23,446.0	18.0
1995	21,501.0	20,347.0	22,151.0	1,885.0	0.0	24,036.0	18.1
1996	22,187.0	20,848.0	22,461.0	2,185.0	0.0	24,646.0	18.2
1997	22,916.0	21,381.0	23,145.0	2,185.0	0.0	25,330.0	18.5

FIGURE 2.3
TU ELECTRIC COMPANY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

System Expansion. Planned capacity expansion will increase total generating capabilities by nearly 30 percent over the forecast period to 23,145 MW. A policy of diversifying the fuel mix is evidenced by the Comanche Peak nuclear plant under construction in Somervell County. TU anticipates adding 1,081-MW nuclear capacity in 1990 and an additional 1,081 in 1992. Nuclear power will provide 5.4 percent of total installed capacity in 1990 and 9.3 percent in 1997. TU expects Comanche Peak, operated as a baseload station, to provide 9.1 percent of power generation in 1990 and 13.4 percent in 1997.

Additions to lignite capacity in units of 750 MW capacity, Twin Oak 1 and 2 in Robertson County in 1994 and 1995, and Forest Grove 1 in Henderson County in 1997, will provide baseload capacity and further reduce reliance on gas to 55.6 percent of total capacity by the end of the forecast period.

Although 23 new 65 MW gas combustion turbines will add 1,495 MW over the 10-year forecast period, eight gas generating units with a total of 566 MW capacity are scheduled to be retired by 1997, for a net addition of 929 MW.

Certain TU power plant sites were initially chosen for generating units no longer planned to be installed over the next 10 years. The potential for adding initially planned capability is limited by financial, water, environmental and transmission requirements, site layout, and fuel supply. Specific units, listed in Chapter One of this volume under "Potential Additions at Existing Sites," may also be limited by ambient air quality standards, station water balance, cooling pond temperature, water discharge permit, and solid waste handling and storage. Site specific study would be needed to determine best technology and size of any unit addition.

Two transmission line construction projects will take place in 1990, including a 0.5 mile 69 KV line in Parker County and 16 miles of 345 KV line in Titus County in a joint project with SWEPCO. Forty-two miles of 138 KV transmission line will be added in the period 1992 to 1994. Scheduled in 1994, two miles of 345 KV line will go up in Dallas County. To enhance interconnection with HL&P, 85 miles of 345 KV line are planned for 1994 in Freestone, Ellis, Navarro, Dallas, and Limestone Counties.

Changes Since December 1985 Filing. The information reported above, from the Company's 1987 filing, reflects several changes that have been made since the Company's 1985 filing. A number of power plant construction projections have been deferred or cancelled. The on-line date for Comanche Peak has been periodically

delayed to reflect the status of licensing delays. The expected dates of commercial operation for Twin Oak Units 1 and 2 have been deferred from 1991 and 1992 to 1994 and 1995, respectively. Forest Grove 1, previously expected to be commercially operational in 1993, is now anticipated to be on line in 1997. Martin Lake 4, a 750-MW lignite unit planned for 1994, has been postponed indefinitely. The deferrals and cancellations reflect lower demand forecasts, and the continued availability of firm cogeneration.

CHAPTER THREE

HOUSTON LIGHTING & POWER COMPANY

Houston Lighting & Power Company is a public utility engaged in generating, purchasing, transmitting, and distributing electricity. The utility's service area covers an estimated 5,000 square miles in the Texas Gulf Coast Region including the City of Houston. HL&P is a member of ERCOT.

HL&P is an investor-owned company. The Company's 1987 revenues totaled $3,000,832,000, while total assets as of December 31, 1987 were valued at $8,687,744,000. The capital structure at that date was comprised of 47.5 percent common equity, 7 percent preferred stock, and 45.5 percent long-term debt.

HL&P is a summer peaking utility with annual peak demand usually occurring during the months of either July or August. Peak demand after adjustments was 10,302 MW in 1987. The winter peak was approximately 3,200 MW less than the summer peak. The utility's 1987 aggregate sales amounted to 55,911,327 MWH. HL&P possesses 12,460 MW of installed capacity. In 1987 about 58 percent of the total electricity generated by the utility used gas as the primary fuel. The remaining electricity was generated utilizing either coal or lignite as the source of energy.

3.1 DEMAND FORECAST

Forecasting Methodology. In formulating its forecasts, HL&P uses projections of the national economy to drive its Service Area Model. This model generates a forecast of local population, employment, income, prices, and other economic variables. In addition, HL&P employs such information as DRI's Chemical Outlook, estimates of self-generation, residential appliance efficiencies, appliance market penetration, changes in industrial load, and weather data in its econometric and end-use modeling systems.

Number of Customers. As shown in Table 3.1, *Number of Customers by Sector*, HL&P provided electric service to 1,147,463 residential customers in 1987. The historical data for the period from 1977 through 1987 reflect an average annual growth rate of 5.3 percent for this class of customers. The Company expects only a 1.6 percent annual growth rate after adjustments for its economic development marketing programs into

TABLE 3.1
Number of customer by Sector
Houston Lighting and Power Company

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	684,064	98,111	1,418	81	N/A
1978	743,634	106,915	1,499	86	N/A
1979	819,297	114,279	1,550	86	N/A
1980	883,755	120,552	1,597	76	N/A
1981	950,577	129,660	1,660	76	N/A
1982	1,027,751	139,544	1,725	77	N/A
1983	1,097,946	149,113	1,768	78	N/A
1984	1,142,903	155,262	1,786	79	N/A
1985	1,155,891	157,975	1,801	81	N/A
1986	1,154,063	157,896	1,762	84	N/A
1987	1,148,085	156,983	1,684	85	N/A
1988	1,154,707	157,676	1,644	86	N/A
1989	1,165,439	158,936	1,646	88	N/A
1990	1,182,568	161,012	1,656	90	N/A
1991	1,202,858	163,553	1,675	91	N/A
1992	1,224,926	166,367	1,700	93	N/A
1993	1,248,238	169,368	1,728	95	N/A
1994	1,272,194	172,472	1,759	96	N/A
1995	1,296,551	175,640	1,790	98	N/A
1996	1,321,177	178,855	1,824	100	N/A
1997	1,346,418	182,156	1,858	101	N/A

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

1997. HL&P served 156,833 commercial customers in 1987. As with the residential sector, the utility projects a rather marked decline in the growth rate down to 1.5 percent over the next ten years from 4.8 percent for the period from 1977 to 1987. The industrial sector also exhibits a decline in the average per annum growth. Over the historical period, 1977 through 1987, this class grew at an average rate of 2.2 percent per year. Only a 0.5 percent annual growth rate is expected for the period from 1987 through 1997. Currently, HL&P serves 1,767 industrial customers.

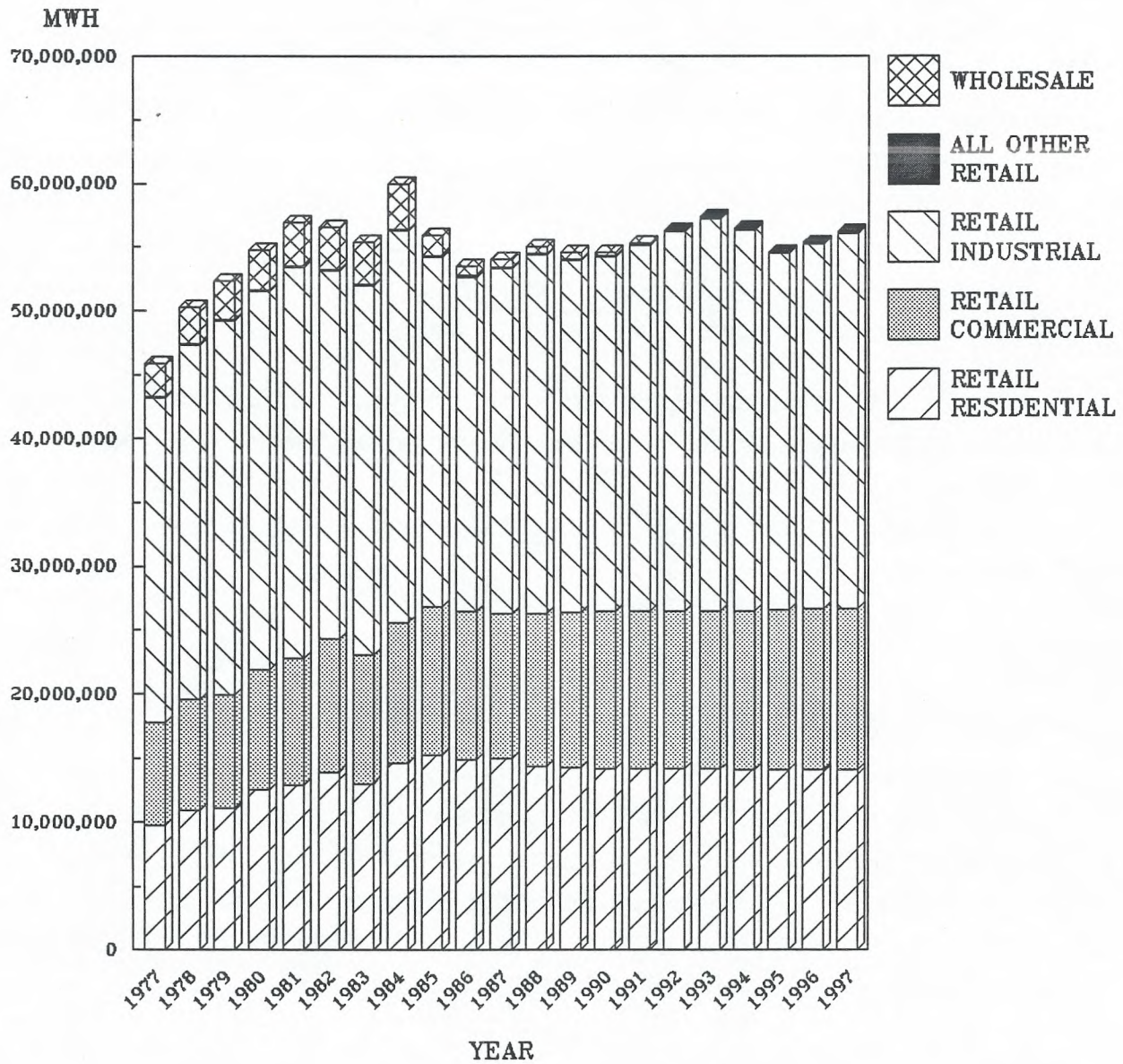
Annual Sales. As shown in Figure 3.1, *Annual Sales by Sector*, the second largest contributor to total sales in 1977 was the residential sector. In that year sales to residential customers comprised 21.3 percent of the aggregate sales. In 1987, the residential sector purchased 14,942,299 MWH of electricity. Currently, this class remains the second largest customer class, purchasing 26.7 percent of the total. HL&P anticipates that the residential sector will maintain this position through 1997. The utility has projected a rate of decline for sales to the residential sector--before adjustments for the proposed marketing programs--of 0.6 percent per year. This is down considerably from the 4.4 percent average annual growth experienced over the previous decade.

Historically, the commercial sector exhibited a growth rate of 3.5 percent annually. HL&P does not expect this rate to continue into the future. The utility is predicting a 1 percent annual growth rate for the period from 1987 through 1997. Sales to commercial customers totaled 11,344,206 MWH in 1987. This amount represents 20.3 percent of the total sales, making the commercial sector the third largest consumer class.

The industrial class is the primary consumer of power in the HL&P service area, having purchased 49.1 percent of the total electricity generated by the Company in 1987. The total industrial sales in that year amounted to 27,441,200 MWH. Unlike the growth rate of either the residential or commercial sector, the industrial sector has demonstrated a relatively slow 0.8 percent annual rate of growth over the past decade. HL&P does not expect much change in this average annual growth, projecting a 0.7 percent annual growth rate over the next ten years. This decline in growth rate is not sufficient to alter its standing as the major purchasing sector. The utility anticipates a small increase in the industrial class contribution to total sales to 52.3 percent by 1997.

The remaining retail sales are composed primarily of sales to municipalities for street lighting and other purposes. These sales amounted to 108,176 MWH in 1987, or 0.2 percent of the total sales for that year. The growth rate for this class is expected to

FIGURE 3.1
HOUSTON LIGHTING AND POWER COMPANY
ANNUAL SALES BY SECTOR (MWH)



SOURCE: TABLE 3.2

TABLE 3.2
Annual Sales by Sector
Houston Lighting and Power Company
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	9,759,137	8,012,512	25,370,150	96,943	2,646,982	45,885,724
1978	10,956,914	8,568,635	27,808,895	103,049	2,838,273	50,275,766
1979	11,078,887	8,813,791	29,309,384	106,847	3,051,593	52,360,502
1980	12,566,097	9,324,496	29,672,733	91,307	3,143,646	54,798,279
1981	12,917,958	9,901,638	30,564,666	92,740	3,403,017	56,880,019
1982	13,924,326	10,382,732	28,866,303	94,244	3,327,122	56,594,727
1983	13,024,945	10,043,436	28,944,329	96,465	3,266,412	55,375,587
1984	14,600,507	11,005,813	30,693,441	99,341	3,586,916	59,986,018
1985	15,210,401	11,580,266	27,418,046	103,808	1,653,429	55,965,950
1986	14,867,274	11,586,187	26,192,806	107,039	721,093	53,474,399
1987	14,942,299	11,344,206	27,045,060	108,176	637,478	54,077,219
1988	14,337,966	11,982,576	28,101,794	114,379	460,976	54,997,691
1989	14,259,020	12,147,415	27,550,520	118,521	506,344	54,581,820
1990	14,193,538	12,223,519	27,801,976	122,663	214,664	54,556,360
1991	14,169,856	12,273,646	28,718,006	126,804	23,818	55,312,130
1992	14,133,329	12,314,890	29,738,123	130,946	0	56,317,288
1993	14,108,886	12,352,875	30,751,889	135,088	0	57,348,738
1994	14,091,859	12,395,918	29,803,743	139,230	0	56,430,750
1995	14,073,325	12,456,292	27,943,392	143,372	0	54,616,381
1996	14,077,550	12,528,248	28,597,033	147,514	0	55,350,345
1997	14,087,098	12,583,905	29,352,754	151,656	0	56,175,413

Note: Annual sales figures are prior to demand-side adjustments.

increase from the 1.1 percent per year over the historical period to 3.4 percent per year over the period from 1987 through 1997. While the growth rate for this class represents the highest rate anticipated by HL&P, the municipal sector is only expected to contribute 0.3 percent to the total sales in 1997.

In 1977 the wholesale sector accounted for a notable 5.8 percent of the total sales. By 1987, however, sales to the wholesale sector had dropped at an average rate of 16.4 percent per year to 441,803 MWH or 0.8 percent of the total. Wholesale sales have been rapidly decreasing since 1977 and this trend is expected to continue. HL&P expects to serve no wholesale customers by 1992.

HL&P is the primary supplier of electric power to Texas-New Mexico Power Company. TNP has no generating capabilities in Texas, but has plans to construct four lignite plants in Robertson County. As these plants begin commercial operation TNP expects to become less dependent on HL&P for electricity.

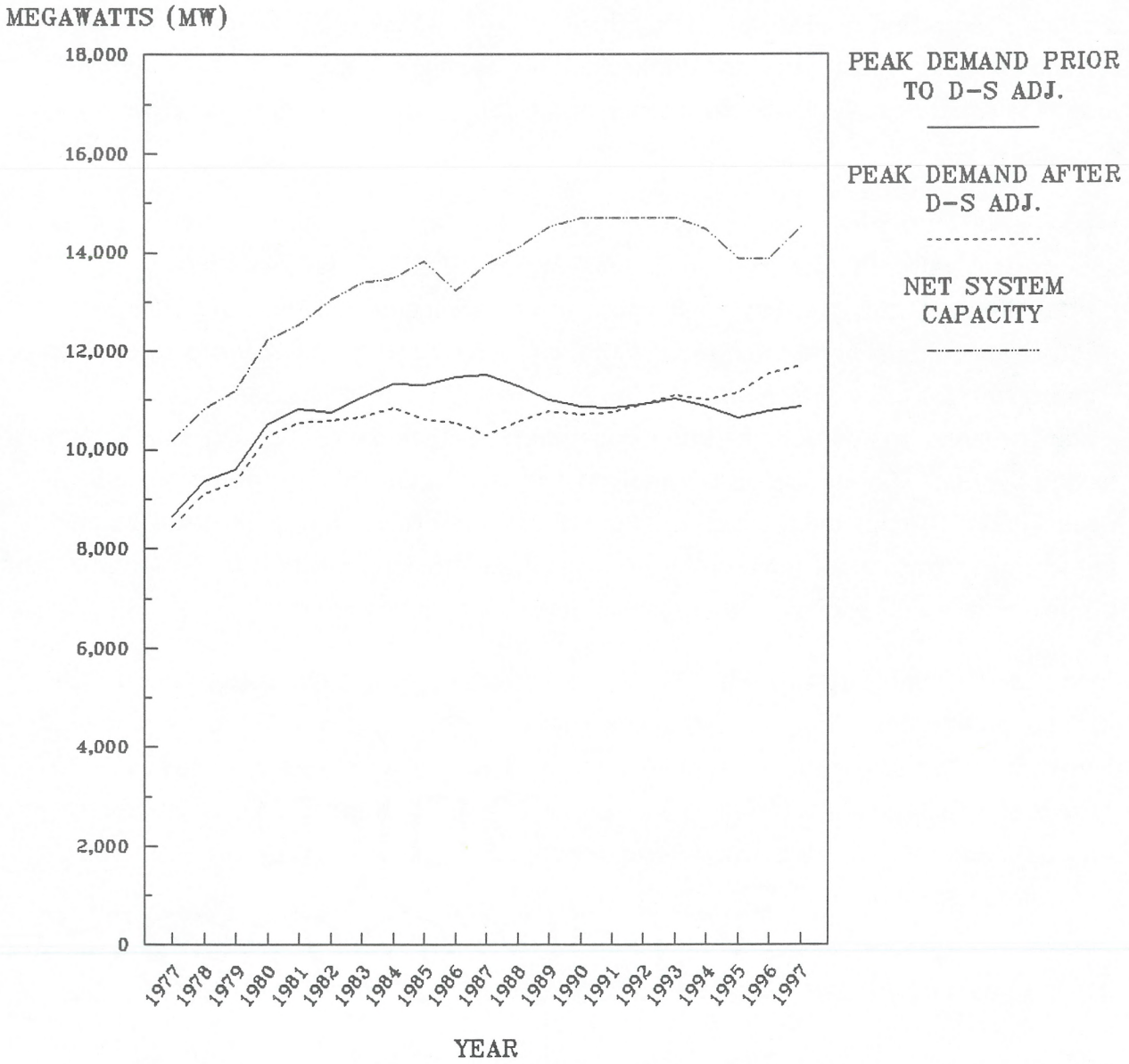
Peak Demand. Over the period from 1977 through 1987 HL&P experienced 2 percent annual growth in peak demand for its system. Figure 3.2, *Net System Capacity and Peak Demand*, shows that peak demand after adjustments rose from 8,445 MW in the base year to 10,302 in 1987. The utility expects growth from 1987 to 1997 to occur at about 1.3 percent annually. HL&P anticipates a peak demand after adjustments of 11,699 MW for its system by 1997.

Of the 1987 total system peak before demand-side adjustments of 11,522 MW, the coincident peak of the residential sector accounted for 38 percent; the industrial sector, 36.9 percent; the commercial sector, 22.4 percent; and the wholesale sector, 2.7 percent.

The most recent data for non-coincident peak is for the year 1986. In this year the sector with the highest non-coincident peak was the residential sector which peaked at 4,595 MW in 1986. The residential sector was followed by the industrial sector with 4,230 MW. The commercial sector reached a peak of 2,818 MW, and the wholesale sector peaked at 498 MW in 1986.

Demand-Side Adjustments. The primary efficiency goal of HL&P is to lower the rates to its customers by increasing sales of electricity. Increased sales would allow fixed costs to be spread over more units of energy, decreasing the rate per KWH charged by the utility. This strategy represents a major departure from the conservation focus of HL&P's past energy efficiency plans. In an effort to achieve this goal, the Company

FIGURE 3.2
HOUSTON LIGHTING AND POWER COMPANY
NET SYSTEM CAPACITY AND PEAK DEMAND



D-S ADJ. is Demand-Side Adjustments.

encourages increased but efficient use of electricity in all customer sectors. In addition, HL&P intends to actively encourage potential industrial and commercial customers to locate in the area. Altering the shape of the load curve is another HL&P objective aimed at improving the efficiency of the utility.

The programs offered to the residential sector focus mainly on increasing the saturation of electric equipment such as dryers, freezers, and heat pumps. These programs consist of advertising campaigns along with a cash rebate to customers who purchase such equipment. For commercial customers the programs are geared primarily toward the increased saturation of electric cooking, heating, and cooling equipment. Additionally, commercial and industrial customers are offered special rebates to substitute electric motors in situations where steam turbines or natural gas are either in use or are likely to be installed.

HL&P also offers programs, to the various sectors, which concentrate on load shifting and off-peak valley filling. To the residential sector, HL&P offers cash incentives with a special discount rate in order to promote the construction and purchase of new all-electric single family homes that meet with the specified energy efficiency requirements. Remote control of customers' air conditioners as well as other appliances will also be made available. In addition, the utility encourages energy-efficient security and building facade lighting. To encourage commercial and small industrial customers to use off-peak energy to cool their facilities, thermal storage programs will be implemented. HL&P also provides an interruptible rate to its industrial customers. The Company offers energy audits and information programs to all of its customers.

In terms of tangible results, HL&P's energy efficiency programs represented a 1,184 MW reduction, including its large interruptible load, in the 1987 peak demand. However, with the Company's revised strategy, a net increase in peak demand of 826 MW is anticipated by 1997. The effects of the utility's adjustments (either up or down) may be seen in Figure 3.2 as the difference between Peak Demand Before Adjustments and Peak Demand After Adjustments.

3.2 CAPACITY PLAN

Efficiency Improvements to Supply. HL&P has submitted ten supply efficiency programs. Five programs deal with cogeneration and renewable sources of energy. Three programs are designed to improve the efficiencies of generating units. The final

two programs focus on the problems of distribution and transmission equipment. The utility reports a total savings of 56,619 KWH for the two distribution and transmission programs. The utility did not provide data on savings for the other programs.

Current Installed Capacity. In 1987 HL&P had an installed capacity of approximately 12,460 MW (See Table 3.3, *Installed Capacity by Fuel Type*). Currently, the overwhelming majority of this capacity is fired using gas. The remainder of the installed capacity is fueled using either coal or lignite. At the close of 1987, HL&P reported a production plant balance of approximately $3.8 billion historical cost and $2.9 billion book value.

Net System Capacity. As shown in Table 3.4, *Net System Capacity and Reserve Margins*, in 1977, the net system capacity for HL&P was 10,170 MW, all of which was the utility's own installed capacity. This capacity resulted in a 20.4 percent reserve margin in that year. The reserve margin is represented in Figure 3.2 as the difference between Peak Demand After Adjustments and Net System Capacity. By 1987, with an increase in installed capacity up to 12,460 MW plus reported firm purchases of 1,295 MW, net capacity had grown to 13,755 MW, depicting an average annual growth rate of 3.1 percent. The utility's reserve margin for 1987 was calculated to be 33.1 percent. HL&P is projecting a slight increase in its net system capacity over the forecast period. The Company expects to achieve this increase through an increase in its installed capacity while dramatically reducing its firm purchases. The utility anticipates an installed capacity of 14,393 MW and firm purchases of only 136 MW. Providing HL&P's projections are accurate, a net system capacity of 14,529 MW would be achieved in 1997, resulting in a reserve margin of 24.2 percent.

Net Generation. As shown in Figure 3.3, *Net Generation by Fuel Type*, in 1977 HL&P generated 99.1 percent of its electricity using gas. The remaining electricity was generated using oil. In 1978 the utility began using coal as an alternative fuel. Over the ten-year period to 1987, with the installation of additional capacity which used either coal or lignite, HL&P succeeded in diversifying its fuel mix considerably from the 1977 composition. By 1987, 57.7 percent of the total electricity generated by the utility used gas as the source of energy. Coal generation contributed 24.1 percent of the total. Lignite-fueled generation accounted for the remaining 18.2 percent. Oil-fired generation was phased out by 1983. By 1997 the Company expects to generate 42.1 percent of its electricity using gas, 27.4 percent using coal, 19.1 percent using lignite, and

TABLE 3.3
Installed Capacity by Fuel Type
Houston Lighting and Power Company
(MW)

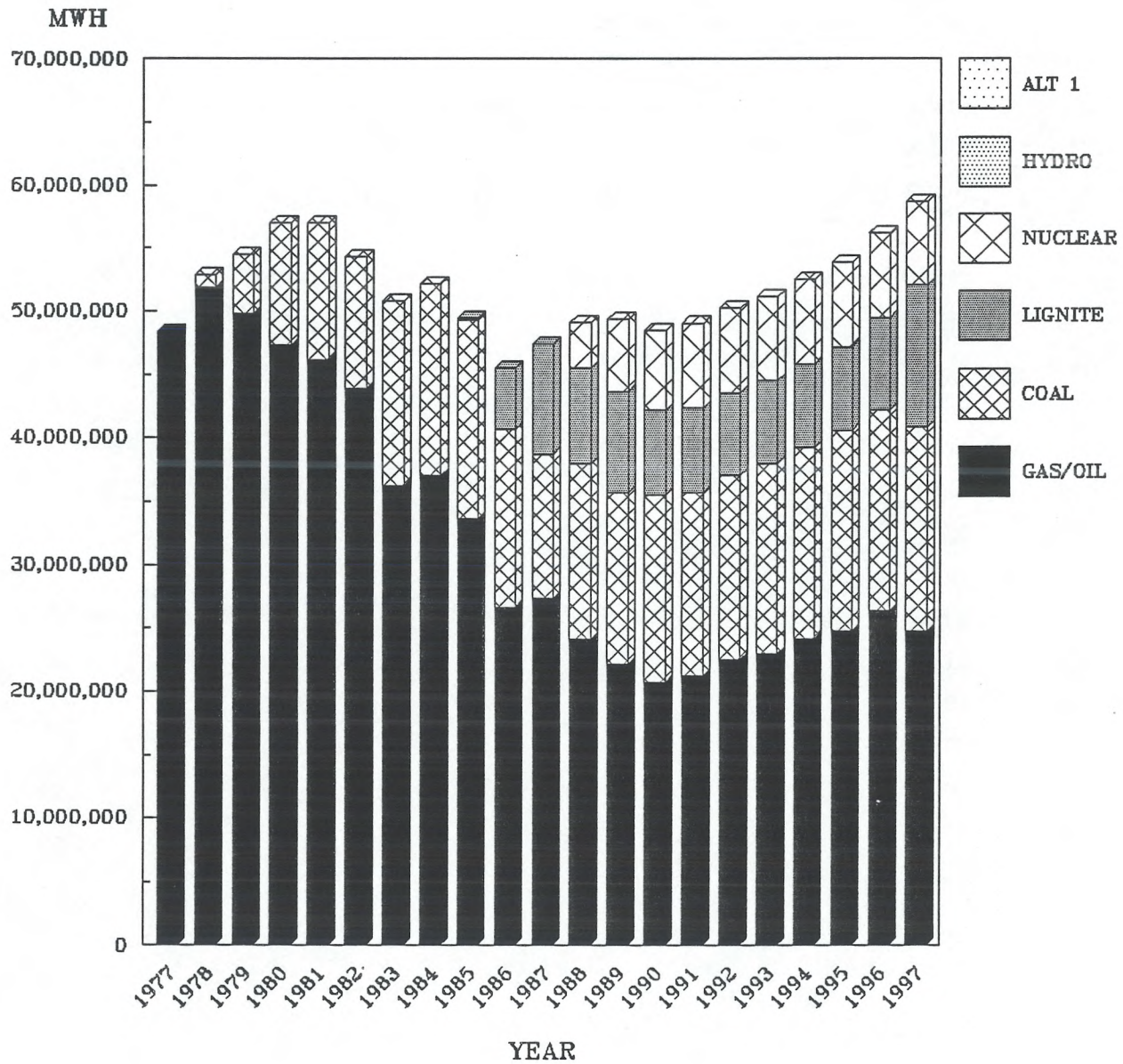
Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	10,170	0	0	0	0	0	10,170
1978	10,168	660	0	0	0	0	10,828
1979	9,873	1,320	0	0	0	0	11,193
1980	9,873	1,871	0	0	0	0	11,744
1981	9,873	1,871	0	0	0	0	11,744
1982	9,873	1,871	0	0	0	0	11,744
1983	9,869	2,327	0	0	0	0	12,196
1984	9,948	2,327	0	0	0	0	12,275
1985	9,948	2,362	0	0	0	0	12,310
1986	8,773	2,335	720	0	0	0	11,828
1987	8,685	2,335	1,440	0	0	0	12,460
1988	9,070	2,401	1,440	385	0	0	13,296
1989	9,070	2,433	1,440	770	0	0	13,713
1990	9,070	2,468	1,440	770	0	0	13,748
1991	9,070	2,468	1,440	770	0	0	13,748
1992	9,070	2,468	1,440	770	0	0	13,748
1993	9,070	2,468	1,440	770	0	0	13,748
1994	9,070	2,468	1,440	770	0	0	13,748
1995	9,070	2,468	1,440	770	0	0	13,748
1996	9,070	2,468	1,440	770	0	0	13,748
1997	9,070	2,468	2,085	770	0	0	14,393

Note: Alternate sources do not include cogeneration.

TABLE 3.4
Net System Capacity and Reserve Margins
Houston Lighting and Power Company
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	8,645	8,445	10,170	0	0	10,170	20.4
1978	9,363	9,115	10,828	0	0	10,828	18.8
1979	9,605	9,339	11,193	0	0	11,193	19.9
1980	10,536	10,267	11,744	500	0	12,244	19.3
1981	10,816	10,537	11,744	800	0	12,544	19.0
1982	10,747	10,596	11,744	1,300	0	13,044	23.1
1983	11,065	10,676	12,196	1,200	0	13,396	25.5
1984	11,333	10,851	12,275	1,195	0	13,470	24.1
1985	11,320	10,618	12,310	1,520	0	13,830	30.2
1986	11,473	10,556	11,828	1,395	0	13,223	25.3
1987	11,522	10,302	12,460	1,295	0	13,755	33.5
1988	11,284	10,576	13,296	820	0	14,116	33.5
1989	11,011	10,769	13,713	820	0	14,533	35.0
1990	10,871	10,715	13,748	956	0	14,704	37.2
1991	10,849	10,760	13,748	956	0	14,704	36.7
1992	10,925	10,919	13,748	956	0	14,704	34.7
1993	11,029	11,089	13,748	956	0	14,704	32.6
1994	10,876	11,010	13,748	731	0	14,479	31.5
1995	10,650	11,152	13,748	136	0	13,884	24.5
1996	10,778	11,529	13,748	136	0	13,884	20.4
1997	10,873	11,699	14,393	136	0	14,529	24.2

FIGURE 3.3
HOUSTON LIGHTING AND POWER COMPANY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

11.4 percent using nuclear energy. HL&P projects its total net generation to be 58,741,000 MWH by 1997.

System Expansion. HL&P has recently added 1,440 MW of capacity to its system. This figure represents two lignite-fired plants, Limestone 1 and 2, each with 720-MW capacity. Unit 1 began commercial operation in 1986, and Unit 2 in 1987. At this time, HL&P owns 30.8 percent of the South Texas Project. Unit 1 began commercial operation in August of 1988. When commercial operation of this station began, 385 MW of capacity was added to the utility's system. Construction on Unit 2 is scheduled to be completed in December of 1988. HL&P expects this station to be commercially operational by June 1989, adding another 385 MW to the system. In addition, the utility has plans for a lignite plant composed of two units. While these units have been deferred a number of times in the past, construction on both Malokoff 1 and 2 is now due to begin in the third quarter of 1992. Both stations will add 645 MW of capacity to the HL&P system. Unit 1 is expected to completed in December 1996, and Unit 2 is scheduled for commercial operation in December of 1998.

HL&P currently has plans to retire four gas plants. The utility does not specify a retirement date for any of these plants, but an approximate date of 1987 is given. These plants include Deepwater, Green Bayou 1 and 2, and T. H. Wharton. The planned retirements will result in a total 309-MW reduction in the HL&P's system capability.

Certain HL&P power plant sites were initially selected for generating units not now planned to be installed over the next ten years. However, the potential for adding initially planned capability is limited by financial, water, environmental and transmission requirements, site layout, and fuel supply. Specific units, listed in Chapter One of this volume under "Potential Additions at Existing Sites," may also be limited by ambient air quality standards, station water balance, cooling pond temperature, water discharge permit, and solid waste handling and storage. Site specific studies would be needed to determine best technology and size of any unit addition.

Included in HL&P's planned construction work are four transmission line projects. The earliest of these projects began in December 1985 and is scheduled to be completed in June 1988. This line is located in Fort Bend and Harris Counties and will consist of 32.5 miles of 345 KV line. The total cost of this project will be $43,000,000. A 46 mile stretch of 345 KV line located in Austin, Harris, Waller, and Washington Counties is due to begin construction in June 1991. The project is expected to last for one year with an

estimated total cost of $102,000,000. The largest transmission line project is scheduled to begin in January 1993 and be completed 18 months later in June 1994. This 87.5 miles of 345 KV line is to be located in Washington, Burleson, Robertson, Milam, and Lee Counties. The total estimated cost of this project is $125,500,000. The final transmission line will be constructed in Henderson County. This particular project consists of 2.5 miles of 345 KV line. The project is scheduled to begin in September 1994 and be completed in December 1996 with a total cost of $13,000,000.

CHAPTER FOUR

GULF STATES UTILITIES COMPANY

Gulf States Utilities Company is a public utility primarily in the business of generating, purchasing, transmitting, and distributing electricity in portions of southeastern Texas and southcentral Louisiana. GSU also operates as a retail gas utility in and around Baton Rouge. The utility's service area extends 350 miles westward from Baton Rouge, Louisiana, to a point about 50 miles east of Austin, Texas. The 28,000 square mile service area encompasses the northern suburbs of Houston, and the cities of Conroe, Huntsville, Port Arthur, Orange, and Beaumont, Texas; Lake Charles and Baton Rouge, Louisiana. GSU is a member of the Southwest Power Pool electric reliability council.

GSU is an investor-owned company. Its revenues for 1987 totaled $1,432,586,000, while total assets as of December 31, 1987 were $6,677,057,000. The Company's capital structure at that date was comprised of 37.8 percent common equity, 11.1 percent preferred stock, and 51.1 percent long-term debt.

The Company holds four wholly owned subsidiaries. Prudential is engaged in the production and marketing of oil and gas. Varibus operates operates intrastate gas pipelines in Louisiana to serve the Company's generating stations. Varibus also owns rights to lignite reserves in east Texas for possible use by the Company or sale to others. Finance was incorporated under the laws of the Netherlands Antilles for the purpose of borrowing funds outside the U.S. and lending the funds to the Company and its subsidiaries. GSG&T, Inc. owns the Lewis Creek station, a 530-MW gas-fired generating plant which is leased and operated by GSU.

GSU, a summer-peaking utility, reported a 1987 peak demand after adjustments which reached 4,821 MW. The Texas portion of that peak was 2,210 MW. Total system sales in 1987 -- with 10 months actual data and two months estimated -- amounted to 26,602,270 MWH with 12,194,478 MWH sold in Texas. GSU has 6,621 MW of installed capacity to generate at the time of peak demand. In 1987 about 70 percent of the total electricity generated by the utility used gas as the primary fuel, with nuclear, coal, and oil providing the rest of the energy.

The 1987 data filed for this report includes two months of estimated rather than historical information.

4.1 DEMAND FORECAST

Forecasting Methodology. GSU uses an end-use approach to arrive at a total sales forecast. For the residential sector, the Residential End-use Energy Planning System (REEPS) enumerates the major household energy-using activities, appliance acquisitions, operating efficiencies, and load patterns to project sales. The Commercial End-use Modeling System (CEDMS), run as a complement to econometric models, factors in square footage of commercial space and the saturation of commercial electrical appliances including lighting to project sales. Discussions with major industrial customers rounds out forecast of total sales. The Company uses the sales forecast and a load shape by end-use as inputs to the Hourly Electric Load Model (HELM) to distribute the energy forecast over time and arrive at the forecast of peak demand.

Number of Customers. As shown in Table 4.1B, *Number of Customers in Texas by Sector*, as of October 1987 GSU provided electric service to 242,594 residential customers in Texas. The historical data for the period from 1977 through 1987 reflect an annual growth rate of 2.3 percent for this class of customers. The number of customers declined from 1984 to 1985 but increased again in 1986. GSU expects growth to continue but at less than 1 percent annually through 1997. In Texas the Company served 28,313 commercial customers as of October 1987. Growth experienced from 1977 to 1987 averaged 2.5 percent per year and the Company projects growth to continue at 1.8 percent over the forecast period. The industrial sector shows the lowest number of customers in 1987 than for any year since 1977. The number of industrial customers peaked in 1983. GSU does not project the number of industrial customers. See Table 4.1A for data on number of customers in the total GSU system.

Annual Sales. As shown in Figure 4.1A and in Table 4.2A, *Annual Sales by Sector*, the industrial class is the primary consumer of power in the GSU service area, having purchased 11,720,568 MWH or 46 percent of the total electricity (excluding wholesale) generated by the Company in 1987. As shown in Figure 4.1B and Table 4.2B, *Annual Sales in Texas by Sector*, industrial customers in Texas purchased 52.5 percent of the sales, or 5,791,664 MWH. Industrial sales demonstrated an average 0.8 percent yearly rate of growth over the past decade despite having fallen since 1984. GSU projects growth in industrial sales in Texas to occur at an annual rate of 1.3 percent, reaching 6,638,462 MWH by 1997.

TABLE 4.1A
Number of customer by Sector
Gulf States Utilities Company — Total System

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	391,031	47,352	7,768	1,603	90
1978	407,761	48,892	7,696	1,693	100
1979	423,850	50,807	6,665	1,768	108
1980	438,560	52,731	6,768	1,870	117
1981	455,160	52,955	6,723	1,898	79
1982	465,162	55,265	7,297	1,912	75
1983	475,782	57,446	7,770	2,033	70
1984	485,711	60,372	7,226	2,112	72
1985	485,825	61,712	6,586	2,282	53
1986	484,608	62,059	5,978	2,376	55
1987	484,895	61,975	5,813	2,411	53
1988	484,269	62,944	5,803	2,503	N/A
1989	484,805	63,511	5,793	2,595	N/A
1990	486,353	64,568	5,782	2,687	N/A
1991	488,533	65,792	5,772	2,779	N/A
1992	489,841	67,075	5,762	2,871	N/A
1993	495,192	68,401	5,752	2,963	N/A
1994	499,357	69,724	5,741	3,056	N/A
1995	503,845	71,248	5,731	3,148	N/A
1996	508,621	72,806	5,721	3,240	N/A
1997	513,443	74,390	5,711	3,332	N/A

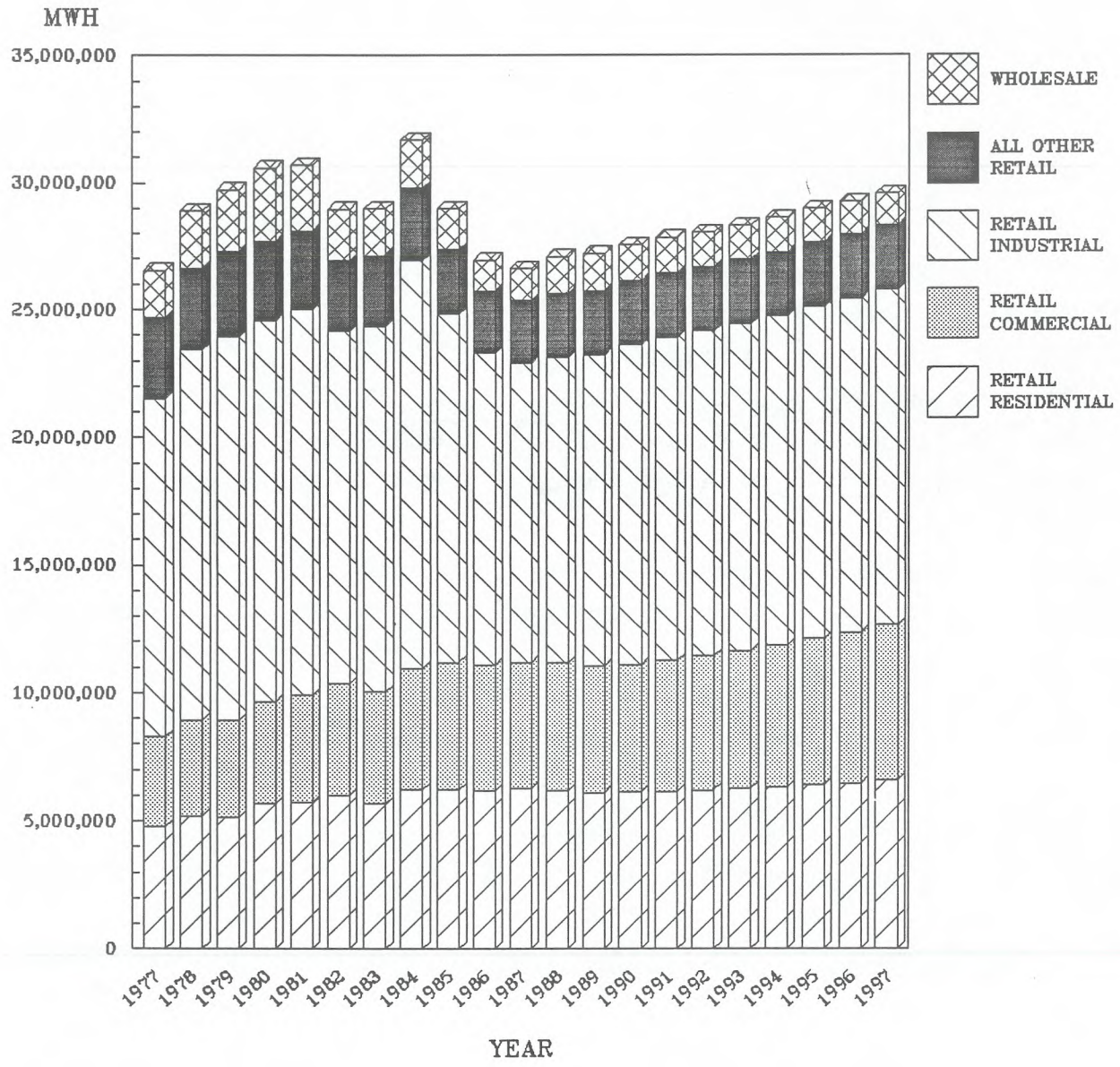
Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

TABLE 4.1B
Number of customer by Sector
Gulf States Utilities Company — Texas Only

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	194,190	22,253	4,334	774	51
1978	203,150	22,706	4,138	824	51
1979	209,927	23,403	3,635	865	56
1980	217,533	24,250	3,632	934	56
1981	226,178	24,859	3,648	948	56
1982	232,163	25,662	4,082	966	56
1983	237,258	26,583	4,257	1,041	53
1984	242,572	27,821	3,957	1,094	54
1985	241,457	28,221	3,626	1,214	41
1986	241,977	28,444	3,330	1,298	39
1987	242,594	28,313	3,285	1,317	38
1988	242,589	28,628	3,288	1,351	37
1989	243,758	28,988	3,292	1,384	37
1990	245,395	29,545	3,295	1,418	36
1991	247,248	30,134	3,298	1,451	35
1992	247,623	30,721	3,301	1,485	34
1993	251,329	31,306	3,305	1,519	34
1994	253,420	31,913	3,308	1,552	33
1995	255,490	32,545	3,311	1,586	32
1996	257,538	33,192	3,314	1,619	31
1997	259,602	33,841	3,318	1,653	31

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 4.1A
GULF STATES UTILITIES COMPANY
TOTAL ANNUAL SALES BY SECTOR (MWH)



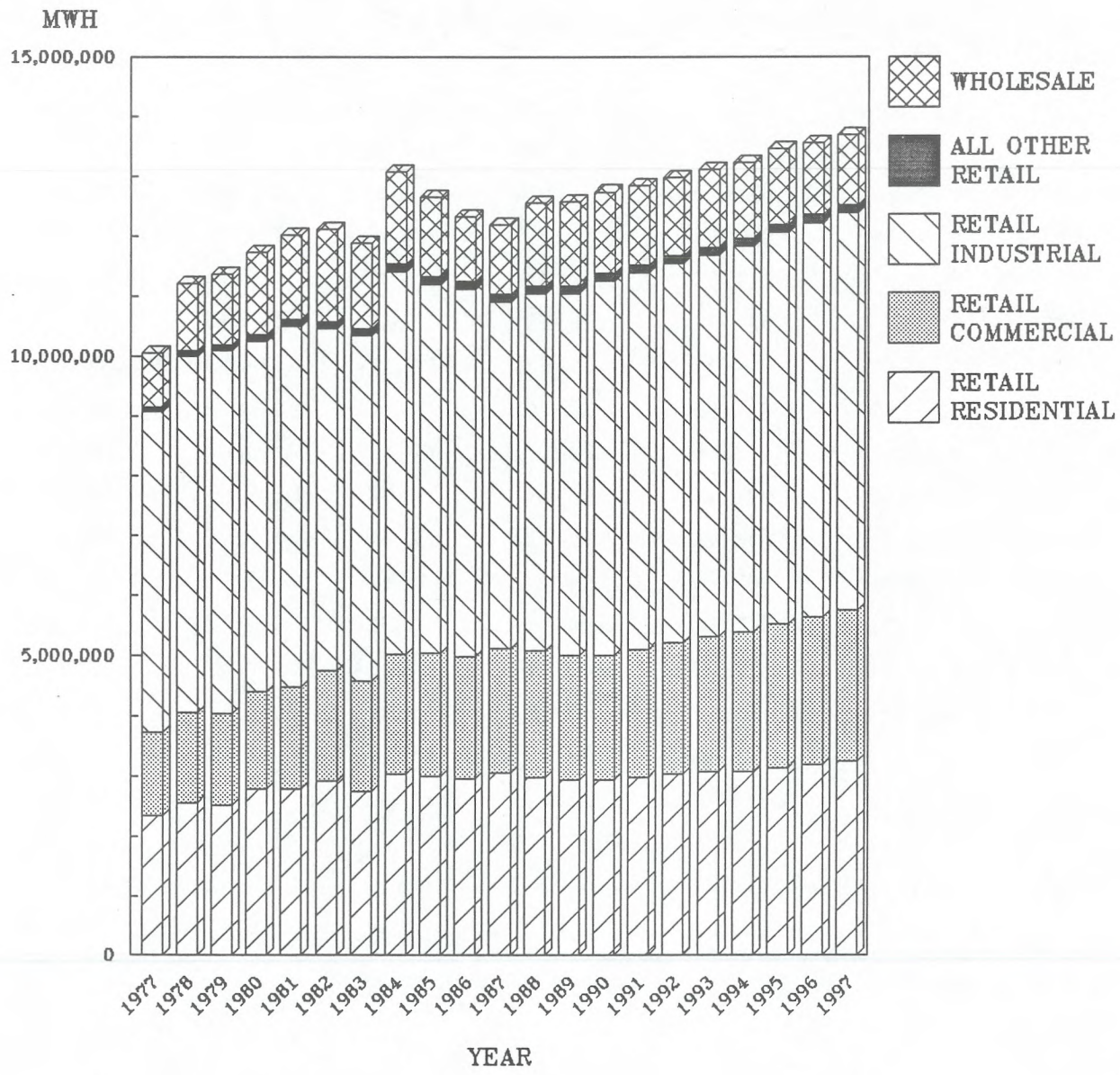
SOURCE: TABLE 4.2A

TABLE 4.2A
Annual Sales by Sector
Gulf States Utilities Company — Total System
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	4,789,630	3,486,193	13,239,841	3,182,951	1,838,601	26,537,216
1978	5,198,421	3,738,114	14,489,775	3,213,732	2,251,489	28,891,531
1979	5,147,436	3,759,289	15,005,270	3,399,477	2,430,477	29,741,949
1980	5,682,016	3,969,390	14,908,111	3,148,992	2,876,973	30,585,482
1981	5,717,715	4,178,126	15,116,636	3,109,686	2,574,857	30,697,020
1982	5,991,578	4,359,739	13,776,639	2,808,449	2,032,097	28,968,502
1983	5,686,436	4,341,093	14,313,066	2,793,954	1,870,934	29,005,483
1984	6,209,347	4,745,055	15,981,756	2,860,348	1,897,392	31,693,898
1985	6,224,555	4,964,416	13,637,479	2,542,782	1,636,027	29,005,259
1986	6,174,567	4,920,883	12,201,260	2,408,740	1,243,563	26,949,013
1987	6,247,559	4,933,988	11,720,568	2,440,523	1,259,632	26,602,270
1988	6,167,789	4,989,571	11,947,109	2,514,923	1,460,674	27,080,066
1989	6,110,521	4,941,000	12,161,808	2,525,904	1,472,428	27,211,661
1990	6,116,640	4,980,000	12,509,053	2,529,568	1,430,450	27,565,711
1991	6,157,652	5,090,000	12,653,918	2,535,157	1,404,235	27,840,962
1992	6,200,330	5,221,000	12,720,299	2,538,905	1,371,935	28,052,469
1993	6,261,981	5,364,000	12,788,131	2,545,086	1,369,712	28,328,910
1994	6,307,870	5,530,000	12,880,325	2,550,680	1,347,858	28,616,733
1995	6,387,171	5,710,000	13,010,407	2,556,583	1,335,844	29,000,005
1996	6,464,967	5,878,000	13,074,220	2,561,840	1,279,446	29,258,473
1997	6,574,802	6,056,000	13,136,637	2,567,201	1,242,860	29,577,500

Note: Annual sales figures are prior to demand-side adjustments.

FIGURE 4.1B
GULF STATES UTILITIES COMPANY
ANNUAL SALES IN TEXAS BY SECTOR (MWH)



SOURCE: TABLE 4.2B

TABLE 4.2B
Annual Sales by Sector
Gulf States Utilities Company — Texas Only
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	2,333,213	1,398,752	5,341,200	91,536	898,994	10,063,695
1978	2,562,314	1,494,930	5,938,679	98,974	1,119,424	11,214,321
1979	2,513,666	1,517,014	6,065,239	103,308	1,170,303	11,369,530
1980	2,781,239	1,612,189	5,867,205	114,759	1,354,778	11,730,170
1981	2,778,863	1,697,824	6,023,816	115,094	1,411,647	12,027,244
1982	2,926,367	1,816,428	5,727,550	115,850	1,532,372	12,118,567
1983	2,751,045	1,813,823	5,782,413	116,605	1,425,244	11,889,130
1984	3,030,826	1,987,281	6,398,581	129,313	1,531,585	13,077,586
1985	2,986,632	2,048,832	6,168,757	127,691	1,334,615	12,666,527
1986	2,955,655	2,027,335	6,137,402	132,145	1,082,931	12,335,468
1987	3,054,486	2,053,189	5,791,664	134,575	1,160,564	12,194,478
1988	2,975,581	2,088,507	5,985,342	132,777	1,388,720	12,570,927
1989	2,945,815	2,044,000	6,062,406	133,417	1,400,257	12,585,895
1990	2,940,814	2,065,000	6,248,363	134,312	1,357,918	12,746,407
1991	2,983,789	2,117,000	6,287,663	135,327	1,331,605	12,855,384
1992	3,042,049	2,173,000	6,332,987	135,509	1,299,024	12,982,569
1993	3,072,497	2,233,000	6,380,288	137,597	1,296,306	13,119,688
1994	3,076,012	2,303,000	6,448,273	138,741	1,273,827	13,239,853
1995	3,138,439	2,374,000	6,552,773	139,875	1,261,086	13,466,173
1996	3,188,836	2,441,000	6,595,018	140,997	1,203,866	13,569,717
1997	3,240,093	2,512,000	6,638,462	142,126	1,166,450	13,699,131

Note: Annual sales figures are prior to demand-side adjustments.

In 1987 the second largest contributor to total sales was the residential sector. Sales to residential customers comprised 24.7 percent of total system sales (excluding wholesale) and 27.7 percent of Texas sales. In 1987 the residential sector in Texas purchased 3,054,486 MWH of electricity. The Company projects an annual growth rate for sales to the residential sector in Texas of 0.6 percent, down from the 2.8 percent average per year experienced from 1977 through 1987.

Historically, the Texas commercial sector exhibited an average growth rate of 4.3 percent annually. GSU predicts 2 percent growth yearly through 1997 in sales to commercial customers, increasing its share to 20 percent of sales excluding wholesale.

The remaining retail sales are composed primarily of sales to municipalities for street lighting and other purposes. These sales amounted to 134,575 MWH in 1987, or about 1 percent of the total sales in Texas for that year. GSU projects growth at 1 percent per year.

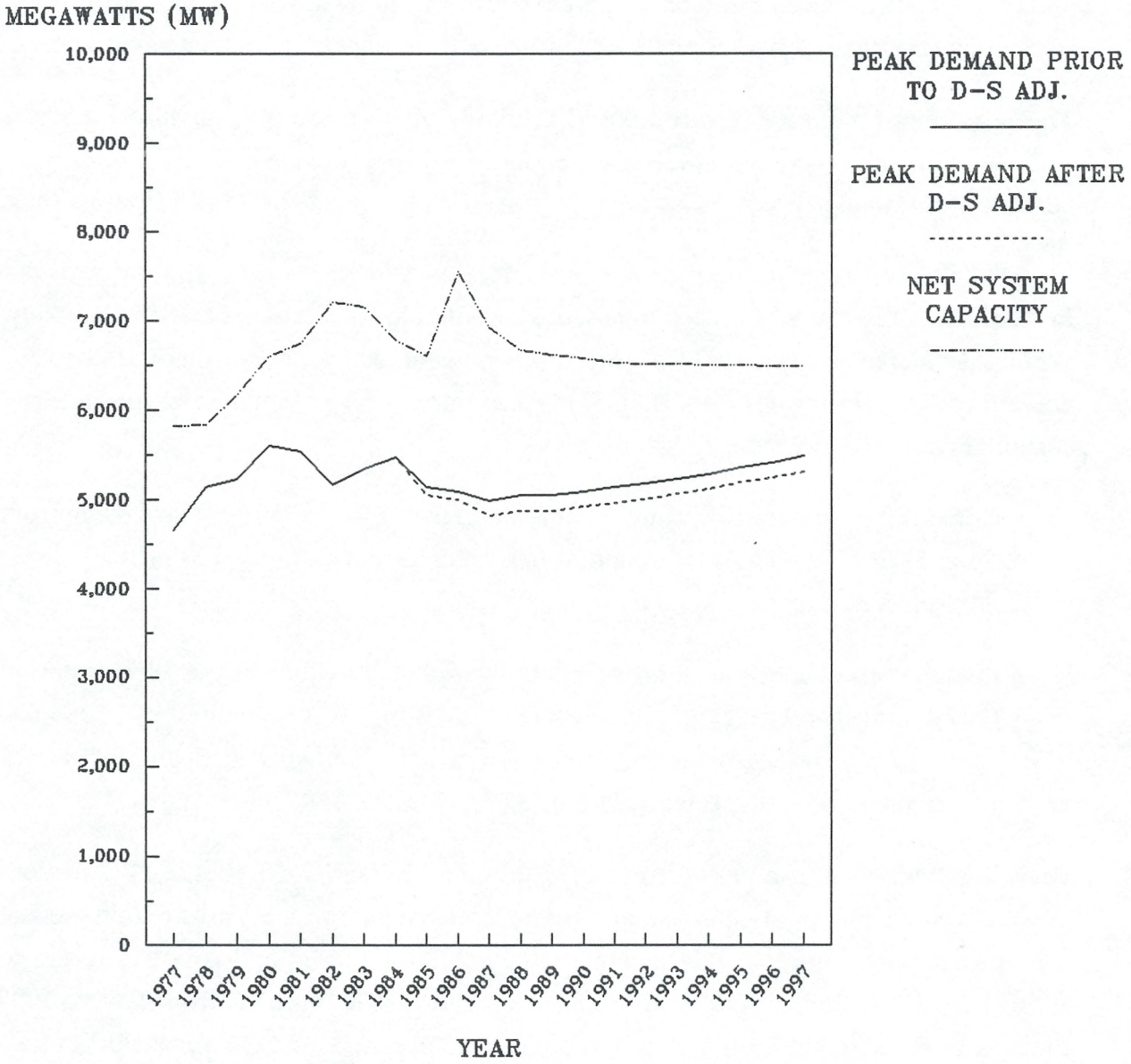
In 1987, 1,160,564 MWH was purchased at wholesale in Texas from the Company. Wholesale increases since 1977 averaged 2.6 percent per year and amounted to 9.5 percent of total Texas sales in 1987. GSU expects almost no growth in sales to wholesale customers over the forecast period.

Off-system sales not under firm contract amounted to 112,257 MWH in 1987, down from the 1986 level of 133,069 MWH but more than 10 times the quantity sold in 1980. GSU does not project non-firm off-system sales.

Even though sales in Texas have been falling since 1984, growth over the 10-year period from 1977 averaged 1.9 percent annually. Total sales in Texas amounted to 12,194,478 MWH in 1987 and will grow at the rate of 1.1 percent annually through 1997 when, according to projections, the sales will total 13,699,131 MWH.

Peak Demand. Over the period from 1977 through 1987 GSU experienced 0.7 percent annual average growth in peak demand for its total system, but the Texas region grew at a 2 percent annual rate. Peak demand actually fell after 1984 and is not expected to surpass the 1987 peak until after 1995. The Company projects growth from 1988 to 1997 to occur at about 0.9 percent annually in both the total system and the Texas portion. As shown in Figure 4.2, *Net System Capacity and Peak Demand*, GSU anticipates a peak demand of 5,313 MW for its total system by 1997.

FIGURE 4.2
GULF STATES UTILITIES COMPANY
NET SYSTEM CAPACITY & PEAK DEMAND



D-S ADJ. is Demand-Side Adjustments.

The coincident peak of the residential sector accounted for about 41 percent of the total system peak demand in 1987 and industrial about 28 percent. GSU projects these percentages to drop slightly with commercial demand to grow slightly to about 18.5 percent of the Texas coincident peak or 21.7 percent of the total system coincident peak. The sector with the highest non-coincident peak in Texas for 1987, the residential sector, required 1,010 MW at some point in 1987, the industrial sector 792 MW, and the commercial sector 520 MW.

Adjustments to Demand. GSU states that its energy efficiency goals are to address the energy efficiency of new construction and customer equipment and improve system efficiency. Two end-user programs offer incentives to customers, dealers, builders and property owners to purchase high efficiency heat pumps and electric water heating equipment. An effort is made to promote construction of highly efficient new homes in the service area.

GSU has contracted for 92 MW of interruptible load in Texas. The Company assumes that its program impacts of conservation and load management activities are embedded in the historic data and, as a result, reports no adjustments to its projections of peak demand due to future conservation and load management activity other than interruptible load.

4.2 CAPACITY PLAN

Efficiency Improvements to Supply. GSU has not presented new programs designed to enhance supply efficiency in the current energy efficiency plan. The Company states that it will continue on-going programs if capital resources are available. Those programs address five improvements in power plant efficiency, and one deals with transmission and distribution.

Current Installed Capacity. In 1987, GSU operated 30 generation units with an installed capacity of approximately 6,621 MW of electricity at the time of the utility's summer peak. Eighty-one percent of this capacity is fueled by gas. As indicated in Table 4.3, *Installed Capacity by Fuel Type*, the Company owns 605 MW of coal-fired capacity and 655 MW of nuclear-powered generating capacity. GSU reported its production plant balance as of December 31, 1987 was $4.6 billion less accumulated depreciation of $0.7 billion for a book value of $3.9 billion.

TABLE 4.3
Installed Capacity by Fuel Type
Gulf States Utilities Company
(MW)

Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	5,506	0	0	0	0	0	5,506
1978	5,522	0	0	0	0	0	5,522
1979	5,456	0	0	0	0	0	5,456
1980	5,944	0	0	0	0	0	5,944
1981	5,944	0	0	0	0	0	5,944
1982	5,920	378	0	0	0	0	6,298
1983	6,010	378	0	0	0	0	6,388
1984	5,899	605	0	0	0	0	6,504
1985	5,429	605	0	0	0	0	6,034
1986	5,429	605	0	655	0	0	6,689
1987	5,361	605	0	655	0	0	6,621
1988	5,161	612	0	655	0	0	6,428
1989	5,161	612	0	655	0	0	6,428
1990	5,161	612	0	655	0	0	6,428
1991	5,161	612	0	655	0	0	6,428
1992	5,161	612	0	655	0	0	6,428
1993	5,161	612	0	655	0	0	6,428
1994	5,161	612	0	655	0	0	6,428
1995	5,161	612	0	655	0	0	6,428
1996	5,161	612	0	655	0	0	6,428
1997	5,161	612	0	655	0	0	6,428

Note: Alternate sources do not include cogeneration.

Net System Capacity. In 1987 the net system capacity for the total system was 6,926 MW at the time of the summer peak as shown in Table 4.4, *Net System Capacity and Reserve Margins*. Firm purchases, for the total system, amounted to 319 MW in 1987, and firm off-system sales totaled 14 MW at the time of the summer peak.

The Company projects firm off-system sales of 15 MW in 1988 and none thereafter. Firm purchases are projected to decline to 57 MW in 1997 at the time of summer peak. GSU attributed a 43.7 percent reserve margin to both the total system and 12 percent to the Texas portion of the system in 1987. With installed capacity remaining at 6,428 MW and declining purchases, the system reserve margin is expected to decline slowly to 22.1 percent in 1997.

Net Generation. As shown in Figure 4.3, *Net Generation by Fuel Type*, gas was used to generate 15,908,299 MWH, or 69.6 percent of the 22,867,437 MWH produced in 1987 by the total system, based on 10 months actual data and two months data projected. The percentage of generation by gas has been falling at an average annual rate of 2 percent since 1977 and is projected to continue falling through the forecast period, although at a slower rate, less than 1 percent per year. Generation from coal amounted to 14 percent of the 1987 total and the River Bend nuclear plant provided 15.7 percent. Output from the nuclear plant is expected to grow at an annual rate of almost 3 percent over the forecast period to reach 4,791,000 MWH in 1997, 20 percent of the projected total. Coal will also provide more power in the future. Coal-fueled generation is expected to increase at the rate of about 3 percent per year.

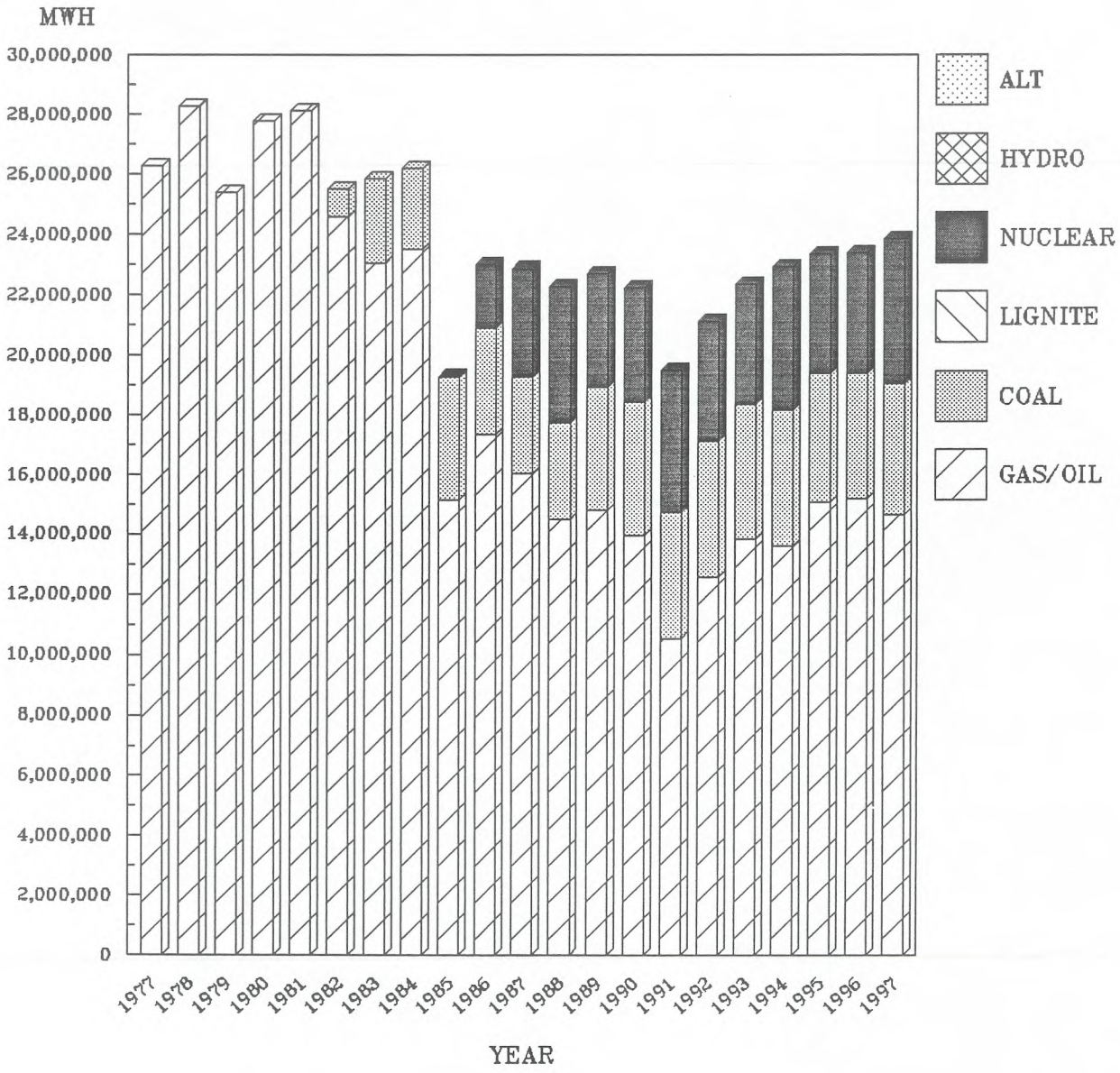
System Expansion. Two gas generators with 100-MW capacity each are scheduled for retirement in 1988. GSU plans no other additions or reductions to the generating capacity over the forecast period.

Certain GSU power plant sites were initially established for generating units not now planned to be installed over the next ten years. However, the potential for adding initially planned capability is limited by financial, water, environmental, and transmission requirements, site layout, and fuel supply. Specific units, listed in Chapter One of this volume under "Potential Additions at Existing Sites," may also be limited by ambient air quality standards, station water balance, cooling pond temperature, water discharge permit, and solid waste handling and storage. Site specific studies would be needed to determine the best technology and size of any unit additions.GSU plans two transmission

TABLE 4.4
Net System Capacity and Reserve Margins
Gulf States Utilities Company
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	4,657	4,657	5,506	313	0	5,819	25.0
1978	5,138	5,138	5,522	313	0	5,835	13.6
1979	5,229	5,229	5,456	713	0	6,169	18.0
1980	5,604	5,604	5,944	666	0	6,610	18.0
1981	5,542	5,542	5,944	801	0	6,745	21.7
1982	5,164	5,164	6,298	910	0	7,208	39.6
1983	5,348	5,348	6,388	764	0	7,152	33.7
1984	5,475	5,475	6,504	276	0	6,780	23.8
1985	5,139	5,056	6,034	586	10	6,610	30.7
1986	5,089	5,006	6,689	872	13	7,548	50.8
1987	4,991	4,821	6,621	319	14	6,926	43.7
1988	5,046	4,875	6,428	253	15	6,666	36.7
1989	5,048	4,877	6,428	192	0	6,620	35.7
1990	5,090	4,919	6,428	151	0	6,579	33.7
1991	5,137	4,966	6,428	98	0	6,526	31.4
1992	5,175	5,004	6,428	88	0	6,516	30.2
1993	5,232	5,061	6,428	88	0	6,516	28.7
1994	5,285	5,114	6,428	77	0	6,505	27.2
1995	5,361	5,190	6,428	77	0	6,505	25.3
1996	5,413	5,242	6,428	57	0	6,485	23.7
1997	5,484	5,313	6,428	57	0	6,485	22.1

FIGURE 4.3
GULF STATES UTILITIES COMPANY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

construction projects, involving 61 miles and 88 miles of 500 KV line in both Texas and Louisiana, for 1993 and 1994.

CHAPTER FIVE

CENTRAL POWER AND LIGHT COMPANY

Central Power And Light Company is a public utility engaged in generating, purchasing, transmitting, and distributing electricity. The utility's service area covers an estimated 44,000 square miles in South Texas, encompassing most of the Rio Grande Valley. The three largest cities served by the utility are Corpus Christi, Laredo, and McAllen. CPL is a subsidiary of Central and South West Corporation and a member of the Electric Reliability Council of Texas.

CPL is an investor-owned company. Its revenues for 1987 totaled $768,264,000, while total assets as of December 31, 1987 were $3,341,949,000. The Company's capital structure was comprised of 45.4 percent common equity, 8.4 percent preferred stock, and 46.2 percent long-term debt.

CPL is a summer-peaking utility. The annual peak demand usually occurs during the months of either July or August. Peak demand after adjustments was 2,814 MW in 1987. The utility projected its 1987 aggregate sales to be 13,952,581 MWH. CPL possesses the installed capacity to generate up to 3,758 MW. In 1987 about 73 percent of the total electricity generated by the utility used gas as the primary fuel. The remaining electricity was generated utilizing either coal or hydroelectric power as the source of energy.

5.1 DEMAND FORECAST

Forecasting Methodology. In formulating its forecasts, CPL uses basically an econometric model which also incorporates certain end-use aspects. Monthly energy consumption, number of customers, and peak load data have been analyzed by a classification of customers in an effort to model homogeneous groups that exhibit similar responses to electric prices and general economic conditions. Annual projections have been obtained by summing the monthly projections. CPL makes its projections using specific assumptions about various conditions such as weather, economic environment, culture, technology, governmental activity, and company activity.

Number of Customers. As shown in Table 5.1, *Number of Customers by Sector*, CPL provided electric service to 455,640 residential customers in 1987. The historical data for

the period from 1977 through 1987 reflect an average annual growth rate of 3.3 percent for this class of customers. The Company expects a 2.3 percent annual growth rate into 1997. CPL served 71,196 commercial customers in 1987. As with the residential sector, the utility projects a decline in the growth rate to 1.9 percent over the next ten years from 3.4 percent for the 1977 to 1987 period. The industrial sector also exhibits a decline in the average per annum growth. Over the historical period, 1977 through 1987, this class grew at a compound rate of 2.1 percent per year. Only a 0.4 percent annual growth rate is expected for the period from 1987 through 1997. Currently, CPL serves 5,600 industrial customers.

Annual Sales. As shown in Figure 5.1 and Table 5.2, *Annual Sales by Sector*, in 1977 the second largest contributor to total sales was the residential sector. In this year sales to residential customers comprised 25 percent of the aggregate sales. In 1987 the residential sector purchased 4,616,823 MWH of electricity. Currently, this class occupies the position as the largest consumer class, purchasing 33.1 percent of the total. The utility has projected an average annual rate of growth for sales to the residential sector of 3.2 percent . This is down somewhat from the 4.7 percent annual growth experienced over the previous decade. However, this decline in growth rate is not sufficient to alter its standing as the major purchasing sector. In fact, the utility anticipates a small increase in the residential class contribution to the total sales, up to 34.7 percent by 1997.

Historically, sales to the commercial sector exhibited a growth rate at 4 percent annually. CPL does not expect sales to this class to maintain this level of growth. The utility is predicting a 2.1 percent annual growth rate for the period from 1987 through 1997. Sales to commercial customers totaled 3,738,040 MWH in 1987. This amount represents 26.8 percent of the total sales which makes this sector the third largest consumer class.

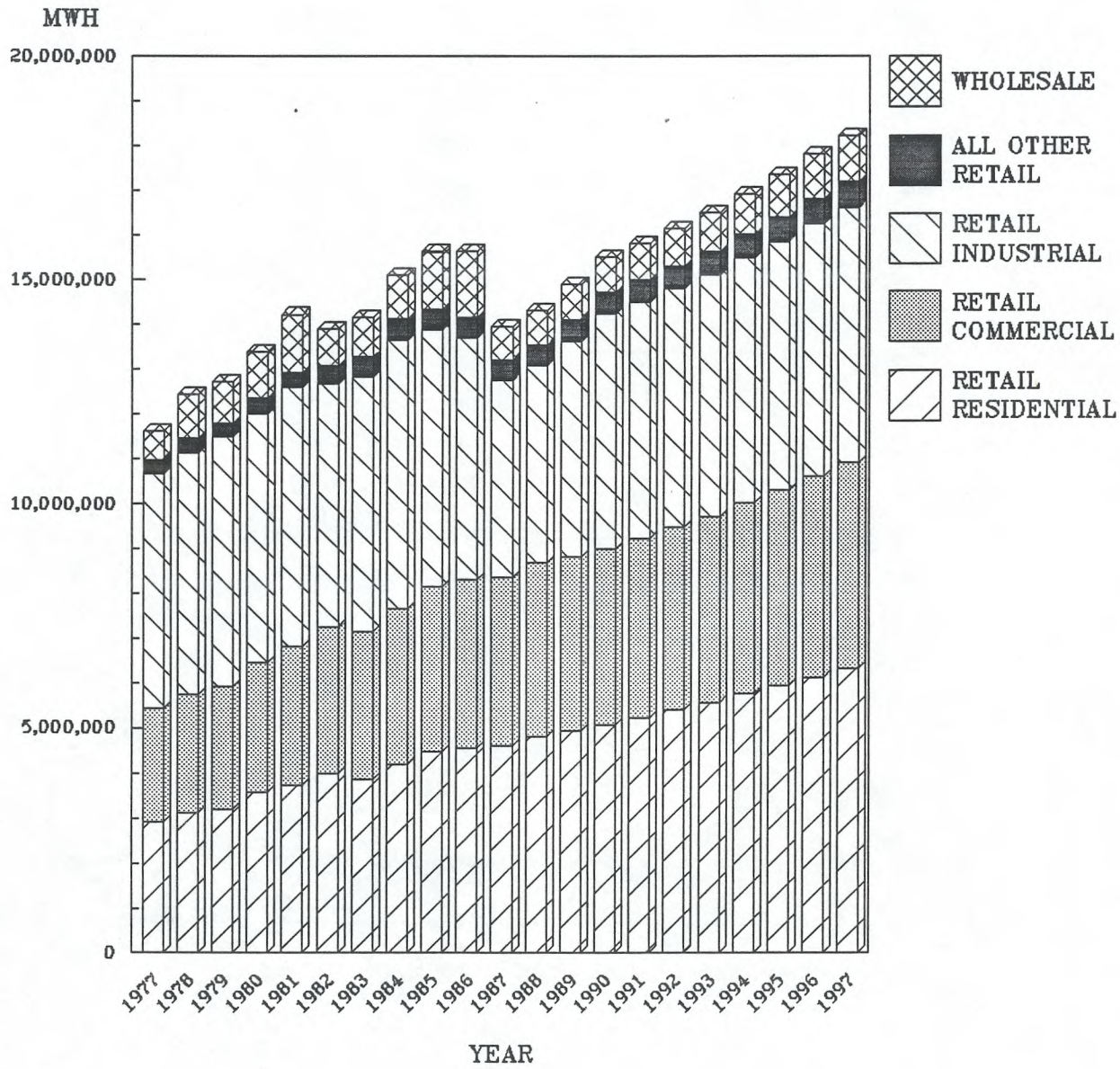
The industrial class is the second largest consumer of power in the CPL service area, having purchased 32.6 percent of the total electricity generated by the Company in 1987. The total industrial sales in that year amounted to 4,404,328 MWH. Unlike the growth rates of the residential or commercial sector, the industrial sector has demonstrated an annual decline of 1.7 percent over the past decade. This decline is due primarily to large industrial customers turning to self-generation and cogeneration. CPL expects this trend to reverse over the next ten years. The utility projects a 2.7 percent annual growth rate through 1997. CPL anticipates that the industrial sector will maintain its position as the second largest consumer group through 1997.

TABLE 5.1
Number of customer by Sector
Central Power and Light Company

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	330,458	51,022	4,558	38	3,782
1978	342,592	55,198	4,751	39	3,851
1979	356,286	57,158	4,865	38	3,935
1980	369,525	58,727	5,151	37	3,980
1981	387,462	61,972	5,416	37	4,098
1982	403,589	64,479	5,654	38	4,113
1983	416,579	66,310	5,686	39	4,076
1984	429,345	68,043	5,801	38	4,150
1985	441,411	69,799	5,831	35	4,180
1986	447,554	70,017	5,631	32	4,140
1987	455,640	71,196	5,600	31	4,171
1988	465,475	72,492	5,613	N/A	4,208
1989	475,506	73,770	5,635	N/A	4,261
1990	486,049	75,111	5,655	N/A	4,320
1991	500,852	76,993	5,683	N/A	4,408
1992	512,215	78,437	5,709	N/A	4,478
1993	523,881	79,921	5,734	N/A	4,549
1994	535,746	81,429	5,759	N/A	4,621
1995	547,861	82,969	5,785	N/A	4,694
1996	560,218	84,541	5,811	N/A	4,770
1997	572,823	86,143	5,836	N/A	4,846

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 5.1
CENTRAL POWER AND LIGHT COMPANY
ANNUAL SALES BY SECTOR (MWH)



SOURCE: TABLE 5.2

TABLE 5.2
Annual Sales by Sector
Central Power and Light Company
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	2,907,406	2,517,413	5,250,383	308,323	643,513	11,627,038
1978	3,108,160	2,640,042	5,371,366	331,930	996,039	12,447,537
1979	3,202,513	2,723,453	5,552,826	328,945	912,388	12,720,125
1980	3,574,451	2,884,947	5,543,161	370,515	1,014,058	13,387,132
1981	3,736,235	3,085,772	5,760,488	340,077	1,298,442	14,221,014
1982	3,988,111	3,278,003	5,399,542	423,655	821,132	13,910,443
1983	3,863,797	3,282,028	5,687,431	438,942	887,007	14,159,205
1984	4,209,063	3,464,842	5,973,426	481,754	979,864	15,108,949
1985	4,469,884	3,676,257	5,727,826	465,979	1,295,588	15,635,534
1986	4,562,301	3,734,403	5,396,358	476,002	1,470,952	15,640,016
1987	4,616,823	3,738,040	4,404,328	460,649	732,741	13,952,581
1988	4,824,618	3,868,660	4,379,098	481,740	760,034	14,314,150
1989	4,937,876	3,888,852	4,791,504	488,754	785,937	14,892,923
1990	5,063,193	3,933,104	5,227,290	497,159	790,152	15,510,898
1991	5,229,584	3,999,416	5,269,907	508,800	814,145	15,821,852
1992	5,405,103	4,074,082	5,321,923	521,002	846,414	16,168,524
1993	5,570,823	4,157,197	5,384,655	532,685	872,459	16,517,819
1994	5,754,033	4,263,082	5,468,322	545,058	909,064	16,939,559
1995	5,941,266	4,371,496	5,554,356	557,727	947,181	17,372,026
1996	6,134,698	4,483,871	5,643,769	570,941	991,854	17,825,133
1997	6,326,415	4,586,758	5,722,840	584,149	1,020,079	18,240,241

Note: Annual sales figures are prior to demand-side adjustments.

The remaining retail sales are composed primarily of sales to cotton gins, sales for irrigation, and sales to municipalities for street lighting and other purposes. These combined sales amounted to 460,649 MWH in 1987, or 3.3 percent of the total sales for that year. The growth rate for this combination of classes is expected to decrease from the 4.1 percent per year over the historical period to 2.4 percent per year over the period from 1987 through 1997.

In 1977 the wholesale sector accounted for a notable 5.5 percent of the total sales. By 1987, sales to this sector had grown at an average rate of 1.3 percent per year to 732,741 MWH or 5.3 percent of the total. This seemingly low growth rate is not necessarily indicative of the trend of sales to the wholesale sector. Sales dropped significantly between 1986 and 1987 resulting in deceptively low average annual growth. Wholesale sales are expected to demonstrate the highest per annum growth of any sector, 3.4 percent through the forecast period. By 1997, CPL projects that 5.6 percent of its total sales will be attributed to the wholesale sector.

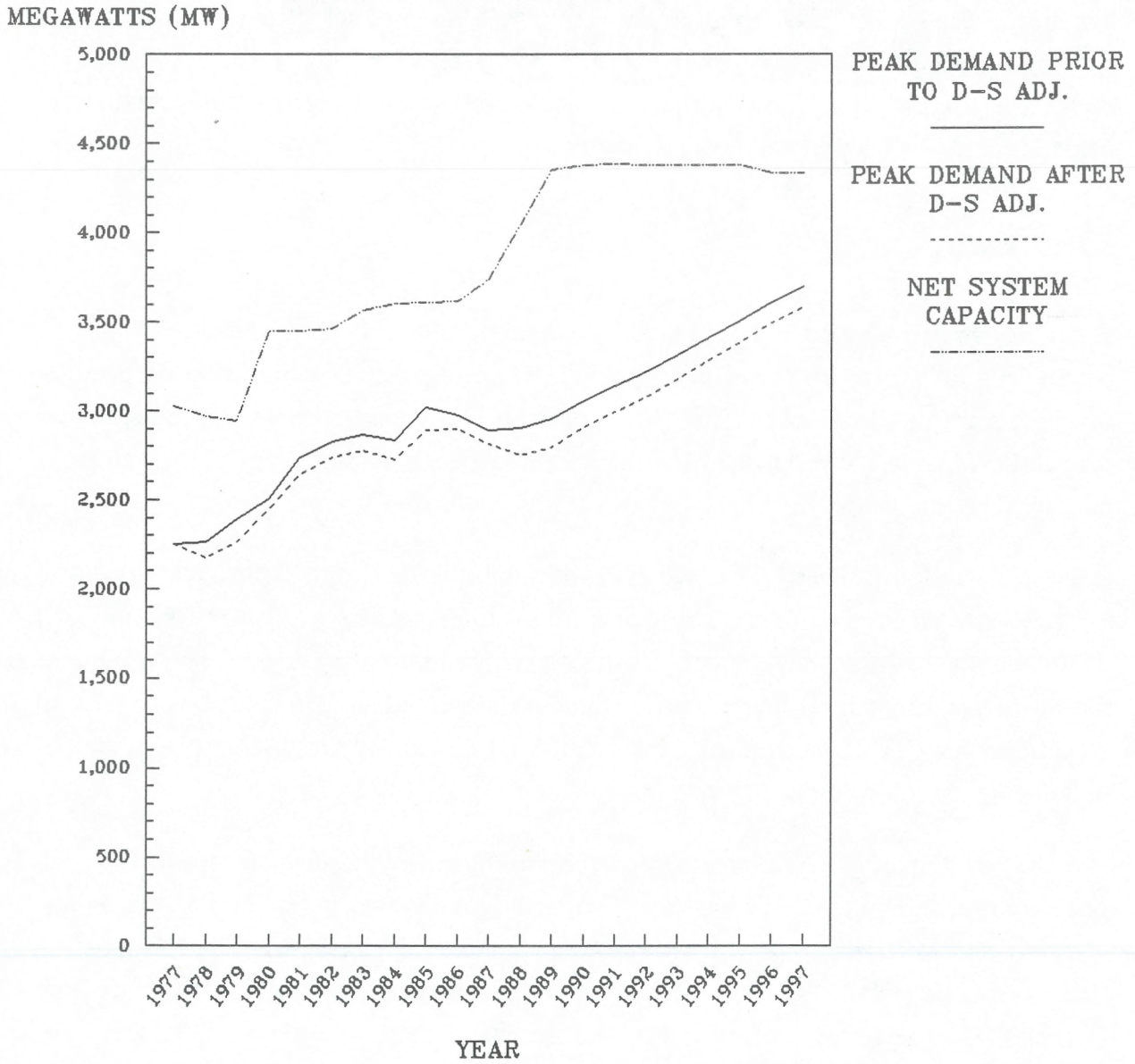
Peak Demand. Over the period from 1977 through 1987 CPL experienced 2 percent annual growth in peak demand for its system. Figure 5.2, *Net System Capacity and Peak Demand*, shows that peak demand rose from 2,247 MW in the base year to 2,814 MW in 1987. The utility expects growth from 1987 to 1997 to occur at about 1.9 percent annually. CPL anticipates a peak demand after adjustments of 3,588 MW for its system by 1997.

Of the 1987 system peak before adjustments of 2,891 MW, the coincident peak of the residential sector accounted for 40.7 percent of the total system peak demand; the commercial sector, 32.7 percent; the industrial sector, 19.1 percent; and the wholesale sector, 4.3 percent.

The sector with the highest 1987 non-coincident peak was the residential sector at 1,433 MW. The industrial sector with 1,070 MW has the second-highest non-coincident peak. The commercial sector reached a peak of 1,046 MW and the wholesale sector peaked at 137 MW in 1987.

Demand-Side Adjustments. CPL has stated its goal is to achieve reliable electric service at the lowest reasonable cost by promoting load factor improvement. In an effort to achieve this goal the utility offers ten demand-side programs to its customers. The majority of the programs encourage residential and commercial customers and home builders to take advantage of new technologies and building materials to improve and

FIGURE 5.2
CENTRAL POWER AND LIGHT COMPANY
NET SYSTEM CAPACITY AND PEAK DEMAND



D-S ADJ. is Demand-Side Adjustments.

upgrade home cooling/heating equipment and thermal integrity. Particular attention is given to the proper sizing of heating, cooling, and lighting equipment. For agricultural and municipal users, a program exists to improve overall pumping plant efficiency. For the industrial customers, the utility offers energy cost reduction through waste heat recovery applications. Finally, an interruptible load is offered to CPL customers and CPL engages in economic development activities to increase electric sales.

CPL reported a 171-MW reduction in peak demand due to its interruptible load. Savings of 55 MW for other conservation and load management programs and an increase in use by 111 MW from the economic development activities are incorporated into the figures provided for peak demand. The effects of the utility's adjustments may be seen in Figure 5.2 as the difference between peak demand before adjustments and peak demand after demand-side adjustments.

5.2 CAPACITY PLAN

Efficiency Improvements to Supply. CPL has submitted 15 supply efficiency programs. Seven programs focus on power plant efficiency improvements, primarily modernization of boiler control equipment. Three programs are designed to lower transmission and distribution losses. Five programs deal with cogeneration and renewable sources of energy. The utility does not report savings in KWH units.

Current Installed Capacity. In 1987 CPL had the installed capacity to generate up to 3,758 MW of electricity. (See Table 5.3, *Installed Capacity by Fuel Type*) Currently, the overwhelming majority, 82.4 percent, of this capacity is fired using gas. The remainder of the installed capacity is fueled using either coal or hydro-electric power. As of December 31, 1987, CPL reported the acquisition cost of its production plants as $0.7 billion with a book value of $0.4 billion.

Net System Capacity. Net system capacity is obtained by adding the net of firm off-system sales and purchases to installed capacity. As shown in Table 5.4, *Net System Capacity and Reserve Margins*, the net system capacity for CPL was 3,028 MW in 1977, the result of an installed capacity of 3,044 MW, firm purchases of 10 MW, and firm sales of 26 MW. The utility maintained a 34.8 percent reserve margin in that year. The reserve margin is represented in Figure 5.2 as the difference between peak demand after demand-side adjustments and net system capacity. In 1987 CPL reported 7 MW in firm purchases, 28 MW in firm sales, and an installed capacity of 3,758 MW resulting in a net

TABLE 5.3
Installed Capacity by Fuel Type
Central Power and Light Company
(MW)

Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	3,044	0	0	0	0	0	3,044
1978	2,976	0	0	0	0	0	2,976
1979	2,976	0	0	0	0	0	2,976
1980	2,954	550	0	0	0	0	3,504
1981	2,954	569	0	0	0	0	3,523
1982	2,954	569	0	0	0	0	3,523
1983	3,010	609	0	0	6	0	3,625
1984	3,052	609	0	0	6	0	3,667
1985	3,073	609	0	0	6	0	3,688
1986	3,093	604	0	0	6	0	3,703
1987	3,095	657	0	0	6	0	3,758
1988	3,095	657	0	315	6	0	4,073
1989	3,095	657	0	630	6	0	4,388
1990	3,095	657	0	630	6	0	4,388
1991	3,095	657	0	630	6	0	4,388
1992	3,095	657	0	630	6	0	4,388
1993	3,095	657	0	630	6	0	4,388
1994	3,095	657	0	630	6	0	4,388
1995	3,095	657	0	630	6	0	4,388
1996	3,052	657	0	630	6	0	4,345
1997	3,052	657	0	630	6	0	4,345

Note: Alternate sources do not include cogeneration.

TABLE 5.4
Net System Capacity and Reserve Margins
Central Power and Light Company
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	2,247	2,247	3,044	10	26	3,028	34.8
1978	2,262	2,174	2,976	10	20	2,966	36.4
1979	2,390	2,263	2,976	10	43	2,943	30.0
1980	2,505	2,451	3,504	0	55	3,449	40.7
1981	2,735	2,643	3,523	0	75	3,448	30.5
1982	2,825	2,737	3,523	0	60	3,463	26.5
1983	2,869	2,774	3,625	11	68	3,568	28.6
1984	2,832	2,725	3,667	14	77	3,604	32.3
1985	3,022	2,888	3,688	14	90	3,612	25.1
1986	2,974	2,897	3,703	14	100	3,617	24.8
1987	2,891	2,814	3,758	7	28	3,737	32.8
1988	2,905	2,753	4,073	7	34	4,046	47.0
1989	2,953	2,797	4,388	7	38	4,357	55.8
1990	3,058	2,910	4,388	7	17	4,378	50.4
1991	3,139	2,996	4,388	7	11	4,384	46.3
1992	3,220	3,080	4,388	7	15	4,380	42.2
1993	3,314	3,181	4,388	7	15	4,380	37.7
1994	3,410	3,284	4,388	7	16	4,379	33.3
1995	3,508	3,386	4,388	7	18	4,377	29.3
1996	3,610	3,492	4,345	7	18	4,334	24.1
1997	3,703	3,588	4,345	7	18	4,334	20.8

capacity of 3,737 MW. The utility's reserve margin for 1987 was calculated to be 32.8 percent. Firm purchases are expected to remain a constant 7 MW per year through 1997. Projections of off-system sales range from 11 MW to 38 MW annually, with 18 MW anticipated in 1997. The projected installed capacity of 4,345 MW in 1997 combined with the net of sales and purchases for that year yield a net system capacity of 4,334 MW for the system. This net capacity would yield a reserve margin of 21 percent for 1997.

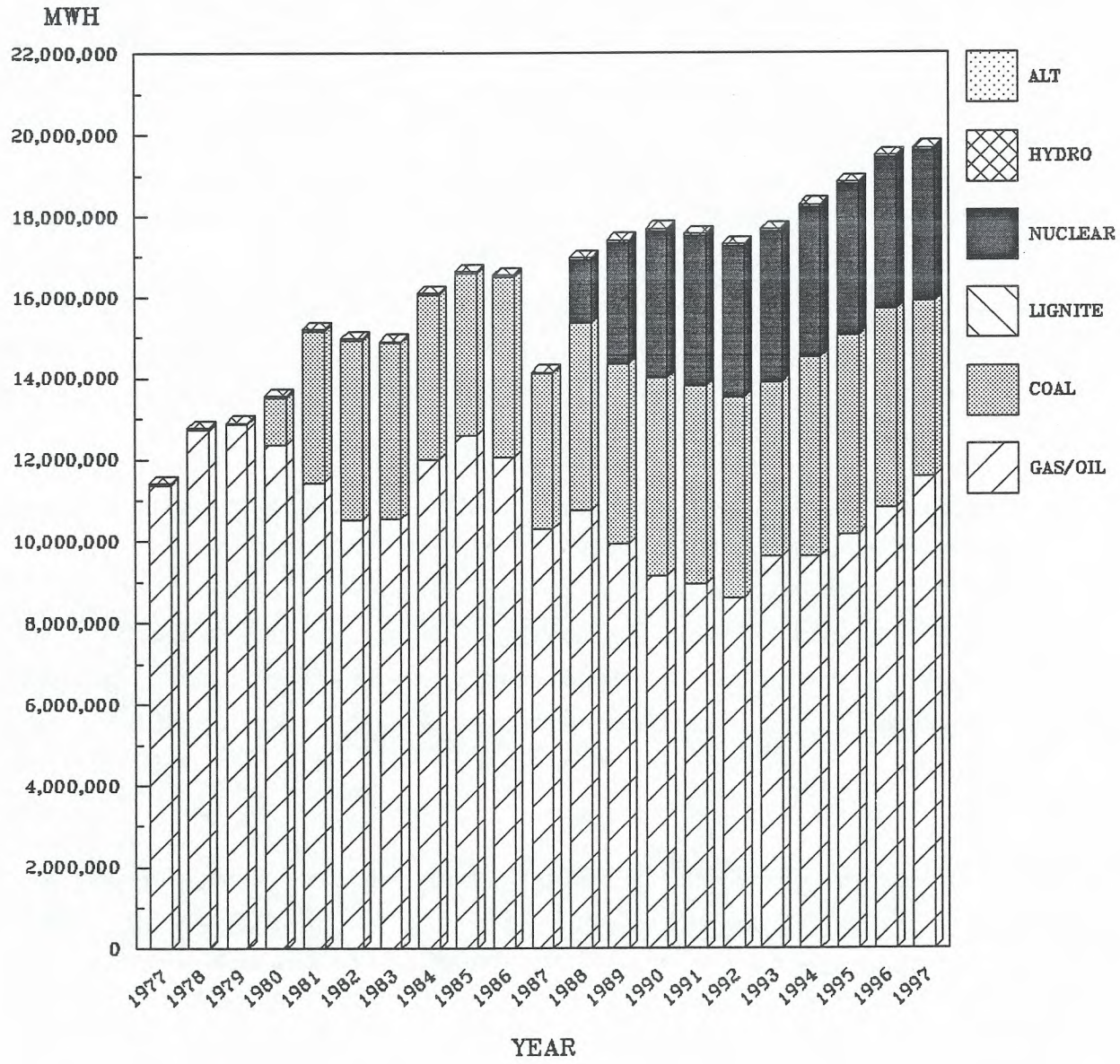
Net Generation. As shown in Figure 5.3, *Net Generation by Fuel Type*, in 1977 CPL generated 99.7 percent of its electricity using gas. The remaining electricity was generated using hydroelectric power. In 1980 the utility began using coal. The installation of additional capacity which used coal enabled CPL to diversify its fuel mix somewhat from the 1977 composition. By 1987, 72.7 percent of the total electricity generated by the utility used gas as the source of energy. Coal generation contributed 26.9 percent of the total. Hydroelectric powered generation accounted for the remaining 0.3 percent. By 1997 the Company expects to generate 58.8 percent of its electricity using gas, 21.9 percent using coal, 19.1 percent using nuclear energy, and 0.3 percent using hydro. CPL projects its total net generation by 1997 to be 19,676,000 MWH, excluding purchased power.

System Expansion. CPL has recently added 53 MW of capacity to its system. This figure represents approximately 7.8 percent of the Oklaunion coal plant in Wilbarger County, Texas. This station began commercial operation in December of 1986. At present, CPL owns 25.2 percent of the South Texas Project. When commercial operation of this station began in August 1988, 315 MW of capacity were added to the utility's system. Construction on Unit 2 is scheduled to be completed in December of 1988. CPL expects this station to be commercially operational by June 1989, adding another 315 MW to the system.

CPL currently has plans to retire one gas plant, La Palma Unit 7. The utility projects the cessation of commercial operation of this generating station will take place in October of 1995. This retirement will result in a total 43-MW reduction in the CPL system.

Certain CPL power plant sites were initially designed for generating units not now planned to be installed over the next ten years. However, the potential for adding initially planned capability is limited by financial, water, environmental and transmission requirements, site layout, and fuel supply. Specific units, listed in Chapter One of this

FIGURE 5.3
CENTRAL POWER AND LIGHT COMPANY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

volume under "Potential Additions at Existing Sites," may also be limited by ambient air quality standards, station water balance, cooling pond temperature, water discharge permit, and solid waste handling and storage. Site specific studies would be needed to determine the best technology and size of any unit addition.

Included in CPL's planned construction work are two transmission line projects. The earliest of these projects is scheduled to begin in May of 1989 and be completed by March of 1990. This line is located in Goliad, Bee, Nueces, and San Patricio Counties and will consist of 73 miles of 345 KV line. The total cost of this project will be an estimated $23,336,000. The second project consists of a back-to-back converter located in Titus County. The utility specifies no starting date for this construction project; however, date of completion is reported as June of 1990. This project is expected to cost CPL $30,191,000.

CHAPTER SIX

CITY PUBLIC SERVICE BOARD OF SAN ANTONIO

The City Public Service Board of San Antonio is the second largest municipally-owned utility in the United States. The utility renders electrical service in San Antonio and its surrounding areas in Bexar County.

The annual peak demand of CPS usually occurs during the months of either July or August. Peak demand after adjustments was 2,551 MW in 1987. The utility projected its 1987 aggregate sales to be 10,385,840 MWH. CPS has installed capacity to generate up to 3,200 MW. In 1987 about 94 percent of the total electricity generated by the utility used gas and coal as the primary fuel, with each of these fuels comprising approximately equal shares.

6.1 DEMAND FORECAST

Forecasting Methodology. In formulating its forecasts, CPS employs econometric models. The utility assesses various economic and demographic factors which have been shown to influence the growth of customers and electricity usage. Employing a population forecast and an analysis of the changing patterns in lifestyle, CPS develops a projection of the number of total households, then translates this projection into an estimate of the number of residential customers. Projections of commercial and industrial customers are formulated using data on the state of the economy and population. The forecasts for numbers of customers are utilized in preparing forecasts for sales and peak demand.

Number of Customers. As shown in Table 6.1, *Number of Customers by Sector*, CPS provided electric service to 403,710 residential customers in 1987. The historical data for the period from 1977 through 1987 reflect an average annual compound growth rate of 4.9 percent for this class of customers. The utility expects a 2.4 percent annual growth rate into 1997.

CPS served 45,983 commercial customers in 1987. As with the residential sector, the utility projects a rather marked decline in the growth rate to 1.9 percent per annum over the next ten years from 5.3 percent per annum for the 1977 to 1987 period. Part of the

TABLE 6.1
Number of customer by Sector
City Public service Board of San Antonio

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	249,267	27,469	1,741	6,933	N/A
1978	261,553	28,769	1,731	7,139	N/A
1979	274,866	29,896	1,708	7,314	N/A
1980	290,839	31,648	1,681	7,580	N/A
1981	305,855	33,175	1,667	7,791	N/A
1982	318,191	34,826	1,500	8,016	N/A
1983	336,152	38,084	1,280	8,097	N/A
1984	361,328	41,074	1,369	8,042	N/A
1985	380,171	43,617	1,351	7,924	N/A
1986	398,141	45,702	1,360	7,940	N/A
1987	403,710	45,983	1,356	7,940	N/A
1988	413,803	47,042	1,357	8,157	N/A
1989	424,709	48,169	1,369	8,303	N/A
1990	436,247	49,229	1,385	8,451	N/A
1991	447,289	50,170	1,399	8,599	N/A
1992	458,382	51,127	1,412	8,747	N/A
1993	469,466	52,047	1,428	8,894	N/A
1994	480,808	52,939	1,447	9,040	N/A
1995	491,003	53,836	1,458	9,189	N/A
1996	501,302	54,682	1,470	9,336	N/A
1997	511,999	55,633	1,484	9,485	N/A

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

growth over the last ten years occurred as industrial customers switched to a commercial rate classification. This is reflected in the 2.5 percent annual decline in the number of industrial customers over the period. Currently serving 1,356 industrial customers, CPS expects the number of industrial customers to grow at an annual rate of 0.9 percent through 1997.

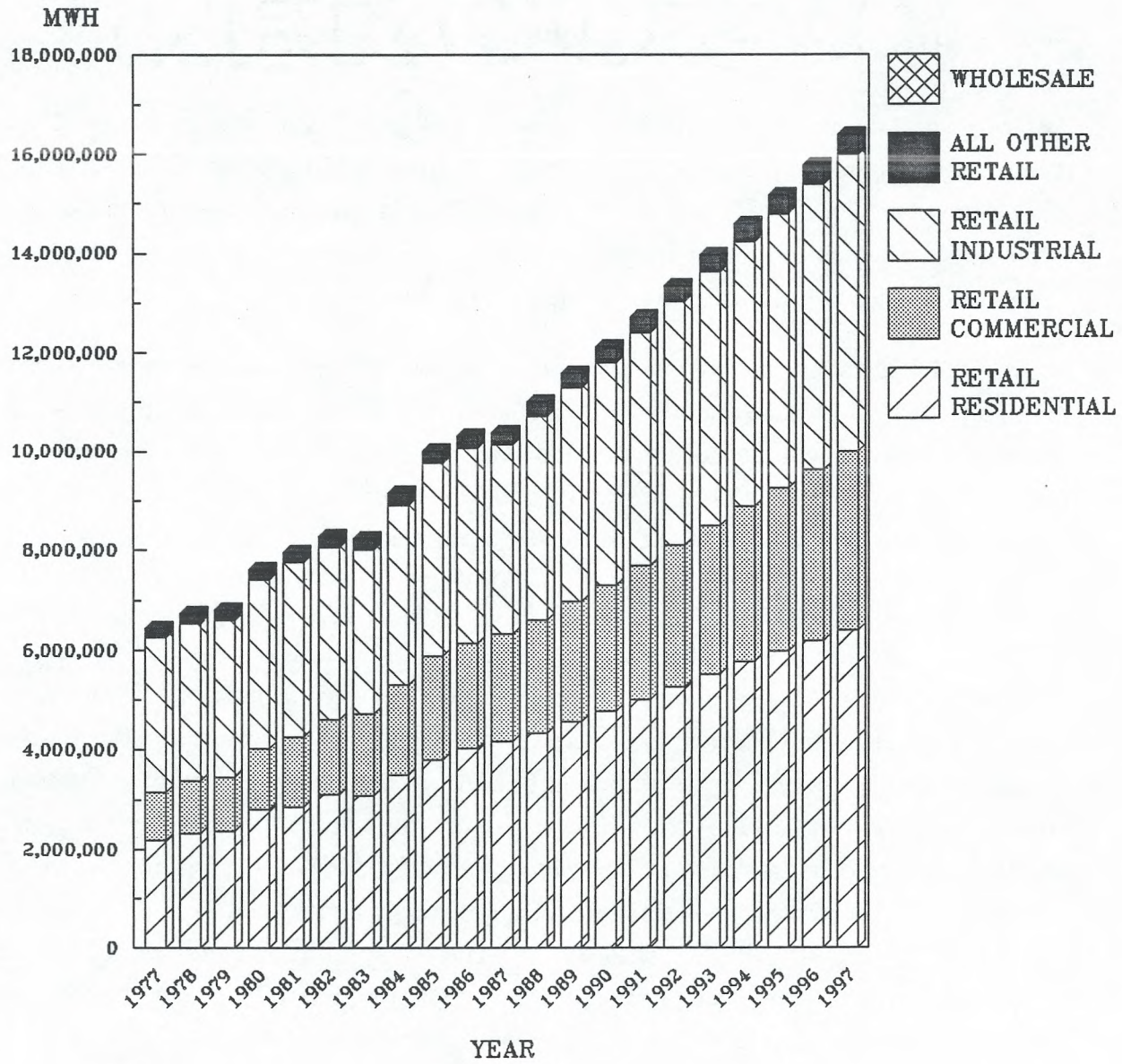
Annual Sales. As shown in Figure 6.1 and Table 6.2, *Annual Sales by Sector*, the second largest contributor to total sales in 1977 was the residential sector. In that year, sales to residential customers comprised 34 percent of the aggregate sales. In 1987, the residential sector purchased 4,163,600 MWH of electricity. Currently, this class occupies the position as the largest customer class, purchasing 40 percent of the total. The utility has projected an average annual compound rate of growth for sales to the residential sector of 4.4 percent. This is down somewhat from the 6.7 percent annual growth experienced over the previous decade. The decline in growth rate is not sufficient to alter its standing as the major purchasing sector. The utility anticipates the residential class contribution to total sales to be 39 percent in 1997.

Historically, sales to the commercial sector exhibited a growth rate of 8.3 percent annually. CPS does not expect sales to maintain this level. The utility predicts a 5.3 percent annual growth rate for the period from 1987 through 1997. Sales to commercial customers totaled 2,155,410 MWH in 1987. This amount represents 21 percent of the total sales, making this sector the third largest customer class.

The industrial class purchased 37 percent of the total electricity generated by the utility in 1987. Industrial sales in that year amounted to 3,805,042 MWH. Over the historical period, sales to the industrial sector demonstrated the lowest growth rate of any sector. With 2.1 percent annual growth, this class of customer moved from its position as the largest consumer in 1977 to the second largest in 1986, primarily the result of continued rate switching away from the industrial sector rate classes in favor of the retail commercial rate classification. CPS assumes no additional long-term switching. Therefore, unlike either the residential or commercial classes, CPS expects an increase in the growth rate for the industrial sector. The utility projects a 4.6 percent annual compound growth rate through 1997. CPS anticipates that the industrial sector will maintain its position as the second largest consumer through 1997.

CPS does not serve any wholesale customers and the remaining retail sales are composed primarily of sales to municipalities for street lighting and other purposes.

FIGURE 6.1
CITY PUBLIC SERVICE – SAN ANTONIO
ANNUAL SALES BY SECTOR (MWH)



SOURCE: TABLE 6.2

TABLE 6.2
Annual Sales by Sector
City Public Service Board of San Antonio
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	2,177,129	969,383	3,094,911	194,700	0	6,436,123
1978	2,328,656	1,050,237	3,159,390	202,338	0	6,740,621
1979	2,367,590	1,099,862	3,121,970	209,791	0	6,799,213
1980	2,819,217	1,216,596	3,363,933	222,332	0	7,622,078
1981	2,852,291	1,412,232	3,477,955	225,218	0	7,967,696
1982	3,109,066	1,504,161	3,441,829	236,458	0	8,291,514
1983	3,092,422	1,636,950	3,279,169	239,654	0	8,248,195
1984	3,503,750	1,807,795	3,594,688	246,530	0	9,152,763
1985	3,806,460	2,071,457	3,875,328	254,669	0	10,007,914
1986	4,027,561	2,113,839	3,913,680	259,263	0	10,314,343
1987	4,163,600	2,155,410	3,805,042	261,788	0	10,385,840
1988	4,341,076	2,264,396	4,112,122	284,924	0	11,002,518
1989	4,561,272	2,410,990	4,316,383	295,952	0	11,584,597
1990	4,760,679	2,537,970	4,502,887	307,533	0	12,109,069
1991	5,005,576	2,685,766	4,706,186	319,787	0	12,717,315
1992	5,262,245	2,840,268	4,914,240	332,597	0	13,349,350
1993	5,512,526	2,983,111	5,121,997	346,112	0	13,963,746
1994	5,767,383	3,125,184	5,339,363	360,344	0	14,592,274
1995	5,975,106	3,271,098	5,539,584	375,279	0	15,161,067
1996	6,185,656	3,427,810	5,754,535	391,086	0	15,759,087
1997	6,391,856	3,599,357	5,984,377	407,658	0	16,383,248

Note: Annual sales figures are prior to demand-side adjustments.

These combined sales amounted to 261,788 MWH in 1987, or 2.5 percent of the total sales for that year. The growth rate for this combination of classes is expected to increase from the 1.6 percent per year over the historical period to 4.5 percent per year over the period from 1987 through 1997.

Peak Demand. Over the period from 1977 through 1987, CPS experienced 4.5 percent average annual compound growth in peak demand for its system. Figure 6.2, *Net System Capacity and Peak Demand*, shows that peak demand rose from 1,641 MW in the base year to 2,551 MW in 1987. The utility expects growth from 1987 to 1997 to occur at about 3.9 percent annually. CPS anticipates a peak demand after adjustments of 3,742 MW for its system by 1997.

The most recent data concerning coincident peak is from 1986. Of the system peak demand after adjustments of 2,596 MW in that year, the coincident peak of the residential sector accounted for 50 percent of the total system peak demand, the industrial sector 30 percent, and the commercial sector, 18.8 percent.

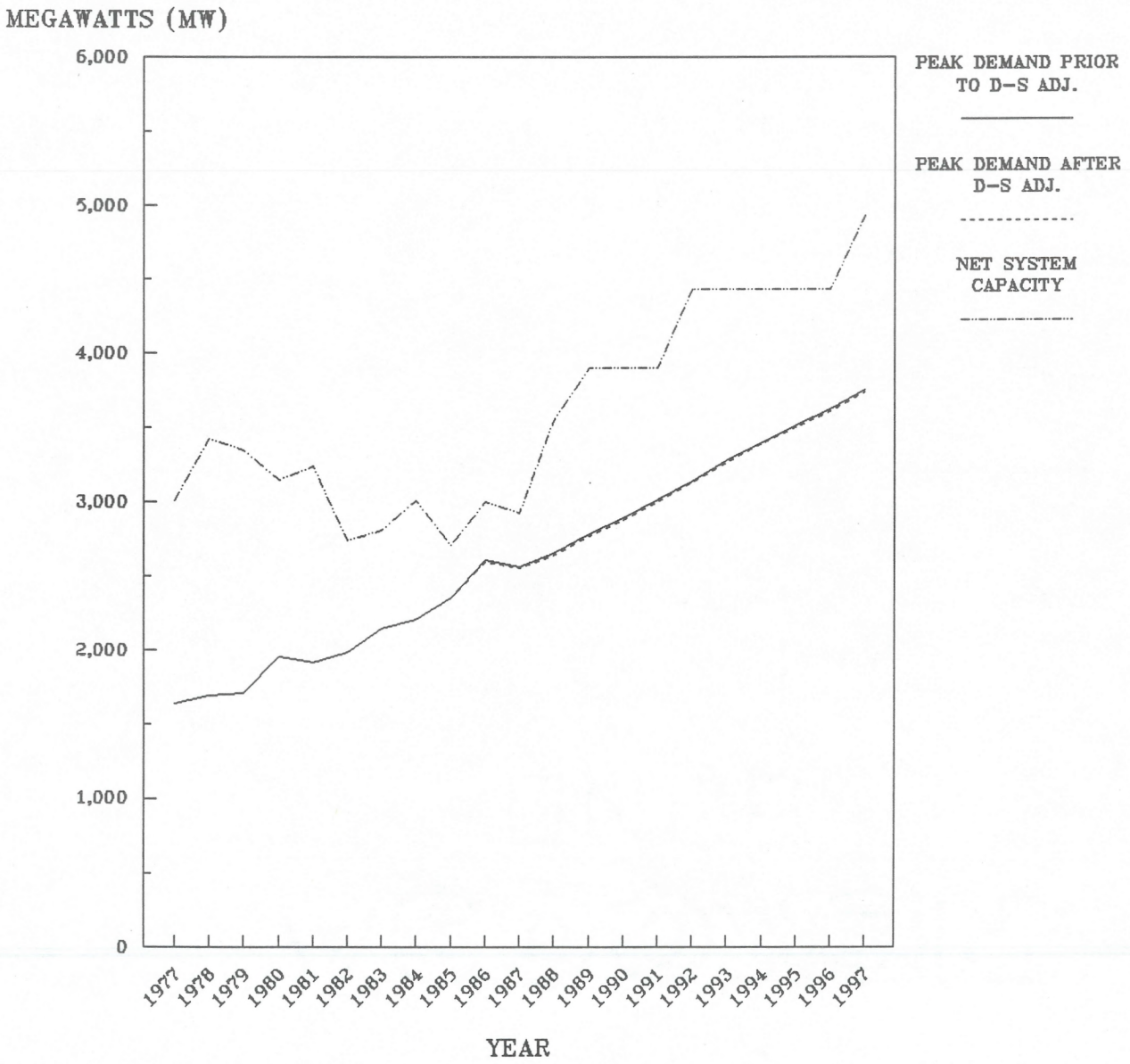
In 1986, the sector with the highest non-coincident peak was the residential sector at 1,597 MW. The residential sector was followed by the industrial sector at 812 MW, and the commercial sector reached a peak of 665 MW.

6.2 CAPACITY PLAN

Installed Capacity. In 1987, CPS had an installed capacity of about 3,200 MW, as shown in Table 6.3, *Installed Capacity by Fuel Type*. The overwhelming majority, 75 percent, of this capacity is fired using gas. The remainder of the installed capacity is fueled using coal.

Net System Capacity. As shown in Table 6.4, *Net System Capacity and Reserve Margins*, the net system capacity for CPS was 3,006 MW in 1977. The utility maintained an 83.2 percent reserve margin in that year. The reserve margin is represented in Figure 6.2 as the difference between peak demand after adjustments and net system capacity. By 1987, with a net system capacity of 2,925 MW, the reserve margin for 1987 was calculated to be 14.7 percent. CPS is projecting an increase in its net system capacity over the forecast period. The utility expects to experience 4.2 percent average annual growth resulting in a net system capacity of 4,932 MW for the system. This net capacity would yield a reserve margin of 31.8 percent for 1997.

FIGURE 6.2
CITY PUBLIC SERVICE – SAN ANTONIO
NET SYSTEM CAPACITY AND PEAK DEMAND



D-S ADJ. is Demand-Side Adjustments.

TABLE 6.3
Installed Capacity by Fuel Type
City Public Service Board of San Antonio
(MW)

Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	2,588	418	0	0	0	0	3,006
1978	2,588	836	0	0	0	0	3,424
1979	2,588	836	0	0	0	0	3,424
1980	2,400	836	0	0	0	0	3,236
1981	2,400	836	0	0	0	0	3,236
1982	2,400	836	0	0	0	0	3,236
1983	2,400	810	0	0	0	0	3,210
1984	2,400	810	0	0	0	0	3,210
1985	2,400	810	0	0	0	0	3,210
1986	2,390	810	0	0	0	0	3,200
1987	2,390	810	0	0	0	0	3,200
1988	2,390	810	0	350	0	0	3,550
1989	2,390	810	0	700	0	0	3,900
1990	2,390	810	0	700	0	0	3,900
1991	2,390	810	0	700	0	0	3,900
1992	2,390	1,308	0	700	0	36	4,434
1993	2,390	1,308	0	700	0	36	4,434
1994	2,390	1,308	0	700	0	36	4,434
1995	2,390	1,308	0	700	0	36	4,434
1996	2,390	1,308	0	700	0	36	4,434
1997	2,390	1,806	0	700	0	36	4,932

Note: Alternate sources do not include cogeneration.

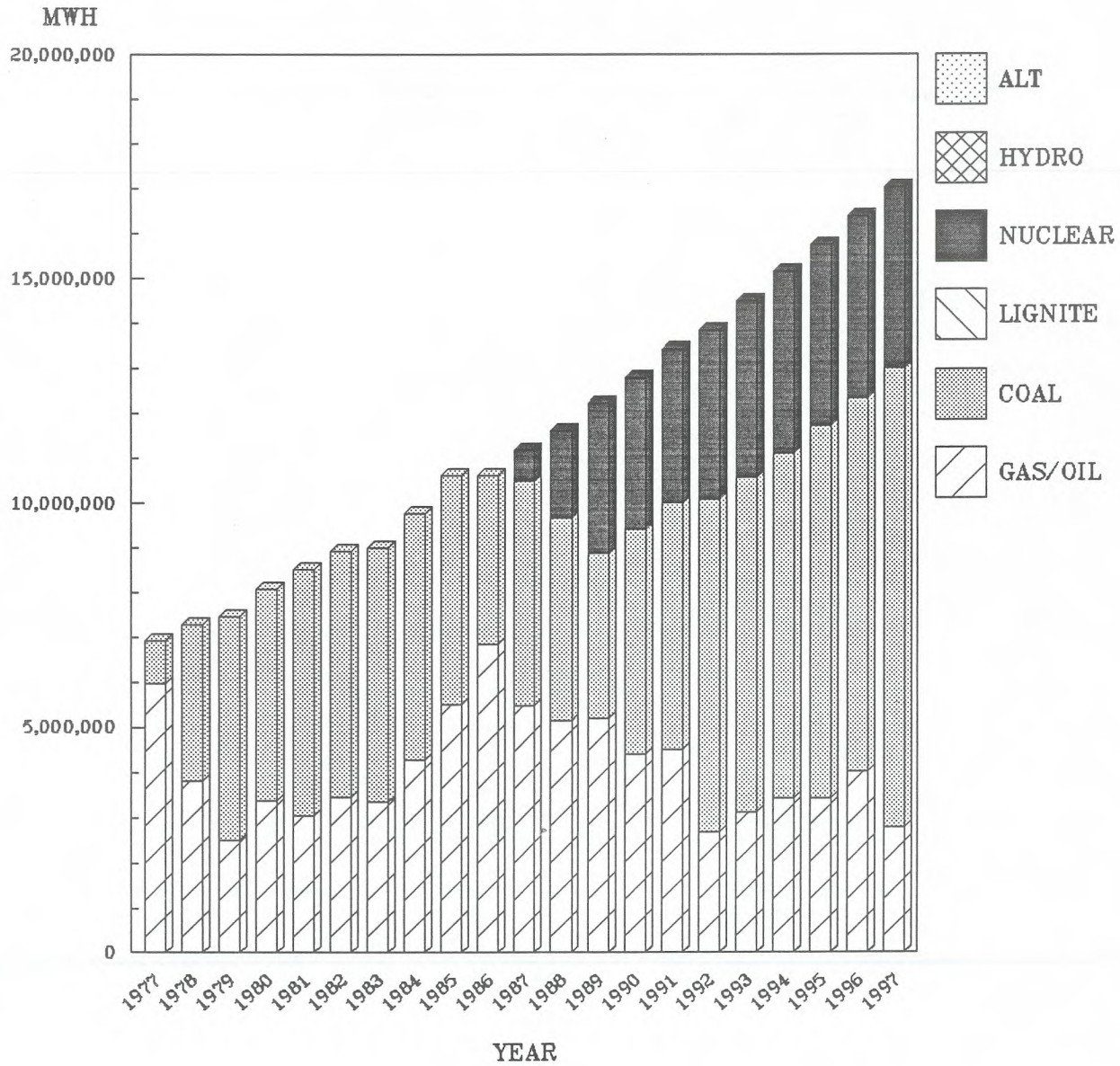
TABLE 6.4
Net System Capacity and Reserve Margins
City Public Service Board of San Antonio
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	1,641	1,641	3,006	0	0	3,006	83.2
1978	1,688	1,688	3,424	0	0	3,424	102.8
1979	1,707	1,707	3,424	0	80	3,344	95.9
1980	1,950	1,950	3,236	0	90	3,146	61.3
1981	1,911	1,911	3,236	0	0	3,236	69.3
1982	1,984	1,984	3,236	0	500	2,736	37.9
1983	2,148	2,148	3,210	0	400	2,810	30.8
1984	2,210	2,210	3,210	0	200	3,010	36.2
1985	2,350	2,350	3,210	0	500	2,710	15.3
1986	2,606	2,596	3,200	0	200	3,000	15.6
1987	2,564	2,551	3,200	0	275	2,925	14.7
1988	2,651	2,638	3,550	0	0	3,550	34.6
1989	2,782	2,769	3,900	0	0	3,900	40.8
1990	2,890	2,877	3,900	0	0	3,900	35.6
1991	3,017	3,004	3,900	0	0	3,900	29.8
1992	3,140	3,127	4,434	0	0	4,434	41.8
1993	3,275	3,262	4,434	0	0	4,434	35.9
1994	3,402	3,389	4,434	0	0	4,434	30.8
1995	3,515	3,502	4,434	0	0	4,434	26.6
1996	3,623	3,610	4,434	0	0	4,434	22.8
1997	3,755	3,742	4,932	0	0	4,932	31.8

Net Generation. As shown in Figure 6.3, *Net Generation by Fuel Type*, CPS generated 86 percent of its electricity using gas in 1977. The remaining electricity was generated using coal.The utility began using coal in that year. The installation of additional capacity using coal enabled CPS to diversify its fuel mix considerably from the 1977 composition. By 1987, about half of the total electricity generated by the utility used gas as the source of energy, and half used coal. As a partner in the South Texas Project, the utility intends to rely less upon gas and more upon coal and nuclear energy. By 1997 the utility expects to generate only 16 percent of its electricity using gas, 59 percent using coal, 23 percent using nuclear energy, and 1.5 percent using municipal solid waste. CPS projects its total net generation will be 17,291,030 MWH by 1997.

System Expansion. At this time, CPS owns 28 percent of the South Texas Project. Unit 1 began commercial operation in August of 1988, reportedly adding 350 MW of capacity to the utility's system. Unit 2 is scheduled to be in commercial operation by June 1989, adding another 350 MW to the system. In addition, CPS has plans for two more coal-fired generating units and one unit fired by municipal solid waste. The coal plants, Calaveras 5 and 6, will augment the utility's system by 498 MW per unit, or a total of 996 MW. Construction on Unit 5 was scheduled to begin in September of 1988 with commercial operation scheduled for May, 1992. Construction on Unit 6 is due to begin in February 1991 and be completed six years later. The utility anticipates commercial operation to commence upon completion of the plant in February of 1997. CPS's Municipal Solid Waste Unit 1 is expected to be under construction by February 1989. Commercial operation is planned for June of 1992. This station is expected to add 36 MW of capacity to the system.

FIGURE 6.3
CITY PUBLIC SERVICE – SAN ANTONIO
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

CHAPTER SEVEN

SOUTHWESTERN PUBLIC SERVICE COMPANY

Southwestern Public Service Company is a public utility engaged in generating, transmitting, and distributing electricity in portions of the Panhandle and South Plains regions of Texas, the Oklahoma Panhandle, eastern New Mexico, and a small part of southwestern Kansas. SPS is a member of the Southwest Power Pool (SPP) electric reliability council.

SPS is an investor-owned utility. Its revenues for 1987 totaled $771,609,000, while total assets as of December 31, 1987 were $1,633,127,000. The Company's capital structure at that date was comprised of 47.5 percent common equity, 8 percent preferred stock, and 44.6 percent long-term debt.

SPS is a summer-peaking utility. The 1987 peak of 2,790 MW occurred in August. The Texas portion of that peak demand was 2,071 MW. The winter peak, which occurred in December of 1986, was approximately 700 MW less than the summer peak. The utility projected its 1987 aggregate sales to be 14,509,927 MWH. SPS has enough installed capacity to generate 4,051 MW. About 53 percent of the 1987 installed capacity used coal as the primary fuel and 46 percent used gas. The remaining 1 percent of electricity was generated utilizing oil as the source of energy.

7.1 DEMAND FORECAST

Forecasting Methodology. In formulating its forecasts, SPS employs an Auto-Regressive Integrated Moving Average model using historical monthly system energy data obtained from company records. The Company subjectively adjusts this forecast to allow for factors such as performance in the economy, new industrial loads, and conservation.

Number of Customers. As shown in Table 7.1B, Number of Customers in Texas by Sector, SPS provided electric service to 194,000 residential customers in Texas in 1987. The historical data for the period from 1981 through 1987 reflect an annual compound growth rate of 0.9 percent for this class of customers. The growth trend in this class of customers to 1997 is 0.2 percent annually. In Texas, the Company served 30,927 commercial customers in 1987. This class experienced an annual compound increase in

the number of customers of 1.8 percent per annum over the six-year period from 1981 to 1987, and the growth trend is 0.9 percent over the period from 1987 through 1997. Within the industrial class, there are fewer customers than existed in 1980 which is a result of customers being reclassified causing a shift between classes. Currently, SPS serves 2,525 industrial customers in Texas. As with the commercial sector, the number of industrial customers is expected to increase at an annual compound rate of 0.9 percent over the forecast period. See Table 7.1A for number of customers in the total SPS system.

Total Sales. In 1980 the residential sector was the fourth largest contributor to total sales. In that year, sales to the residential customers comprised 14.6 percent of the aggregate sales. As indicated in Figure 7.1B and Table 7.2B, *Annual Sales in Texas by Sector*, the residential sector purchased 1,594,231 MWH of electricity in 1987. Currently, this class is the third largest customer class, purchasing 15 percent of the total. SPS anticipates that the residential sector will maintain this position through 1997. The utility has projected an annual compound growth rate for sales to the residential sector of 1.7 percent. This is up slightly from the 1.5 percent experienced for the years 1980 through 1987. Comparable data for total SPS system is shown in Figure 7.1A and Table 7.2A.

The commercial sector in Texas exhibited an average annual compound rate of decline at 1.7 percent from 1980 to 1987. SPS does not expect this rate to continue. The utility is predicting a 3 percent annual increase for the period from 1987 through 1997. Sales to commercial customers totaled 1,322,011 MWH in 1987. This amount represents 12.5 percent of the total sales, making this sector the fourth largest customer class in Texas.

The industrial class is the primary consumer of power in the SPS service area, having purchased 51 percent of the total electricity sold in Texas by the Company in 1987. The total industrial sales in Texas that year amounted to 5,444,773 MWH. This sector demonstrated a compound annual 3.1 percent rate of growth between 1980 and 1987. SPS has a less optimistic outlook for the future, projecting only 1.4 percent annual growth over the next ten years. This decline in growth rate is not sufficient to alter the standing of the industrial class as the major purchasing sector. The utility anticipates the industrial class' contribution to the total sales to decrease only slightly to 49 percent by 1997. The remaining retail sales are composed primarily of sales to municipalities for street lighting and other purposes. These sales in Texas amounted to 432,629 MWH in 1987, or 4 percent of the total sales for that year. The growth rate for this class is expected to be 3 percent per year over the period from 1987 through 1997.

TABLE 7.1A
Number of customer by Sector
Southwestern Public Service Company — Total System

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	N/A	N/A	N/A	0	N/A
1978	220,586	35,208	3,653	24,013	26
1979	225,198	35,944	3,730	24,515	27
1980	236,965	34,220	3,093	22,589	122
1981	243,442	36,303	1,950	23,630	121
1982	248,543	37,211	2,118	24,449	20
1983	268,260	42,594	4,075	27,078	22
1984	272,934	42,842	4,409	27,664	21
1985	274,506	43,289	4,642	27,896	22
1986	272,950	42,947	4,757	28,090	21
1987	272,359	42,837	4,775	28,564	21
1988	272,768	43,214	4,819	29,090	21
1989	273,177	43,594	4,865	29,627	21
1990	273,586	43,978	4,910	30,176	21
1991	273,997	44,365	4,956	30,736	21
1992	274,408	44,755	5,002	31,308	21
1993	274,819	45,149	5,049	31,892	21
1994	275,232	45,546	5,096	32,489	21
1995	275,645	45,947	5,144	33,098	21
1996	276,058	46,352	5,192	33,720	21
1997	276,472	46,759	5,241	34,355	21

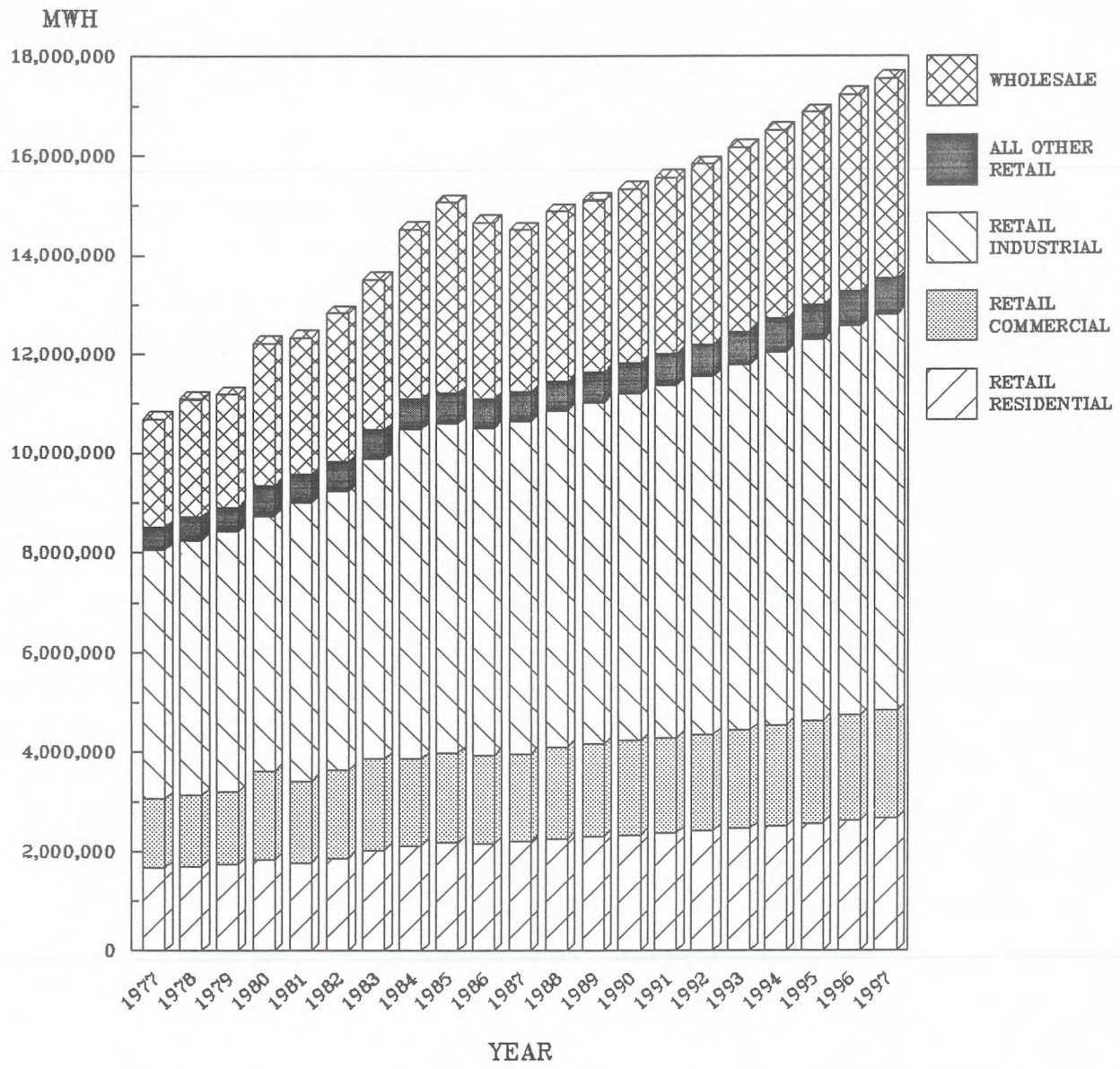
Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

TABLE 7.1B
Number of customer by Sector
Southwestern Public Service Company — Texas Only

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	N/A	N/A	N/A	0	N/A
1978	169,355	27,415	2,202	17,410	22
1979	172,907	27,990	2,248	17,775	22
1980	178,518	25,772	2,936	16,739	100
1981	183,384	27,729	1,779	17,491	100
1982	187,121	28,435	1,930	18,033	14
1983	189,872	30,625	2,160	18,176	14
1984	193,429	30,764	2,315	18,634	15
1985	194,325	31,062	2,385	18,708	15
1986	194,318	30,959	2,510	18,949	15
1987	194,000	30,927	2,525	19,061	16
1988	194,291	31,216	2,548	19,409	16
1989	194,582	31,508	2,572	19,765	16
1990	194,874	31,803	2,596	20,128	16
1991	195,167	32,100	2,621	20,499	16
1992	195,459	32,400	2,645	20,878	16
1993	195,753	32,703	2,670	21,264	16
1994	196,046	33,009	2,695	21,659	16
1995	196,340	33,317	2,720	22,063	16
1996	196,635	33,629	2,746	22,475	16
1997	196,930	33,929	2,771	22,896	16

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 7.1A
SOUTHWESTERN PUBLIC SERVICE COMPANY
TOTAL ANNUAL SALES BY SECTOR (MWH)



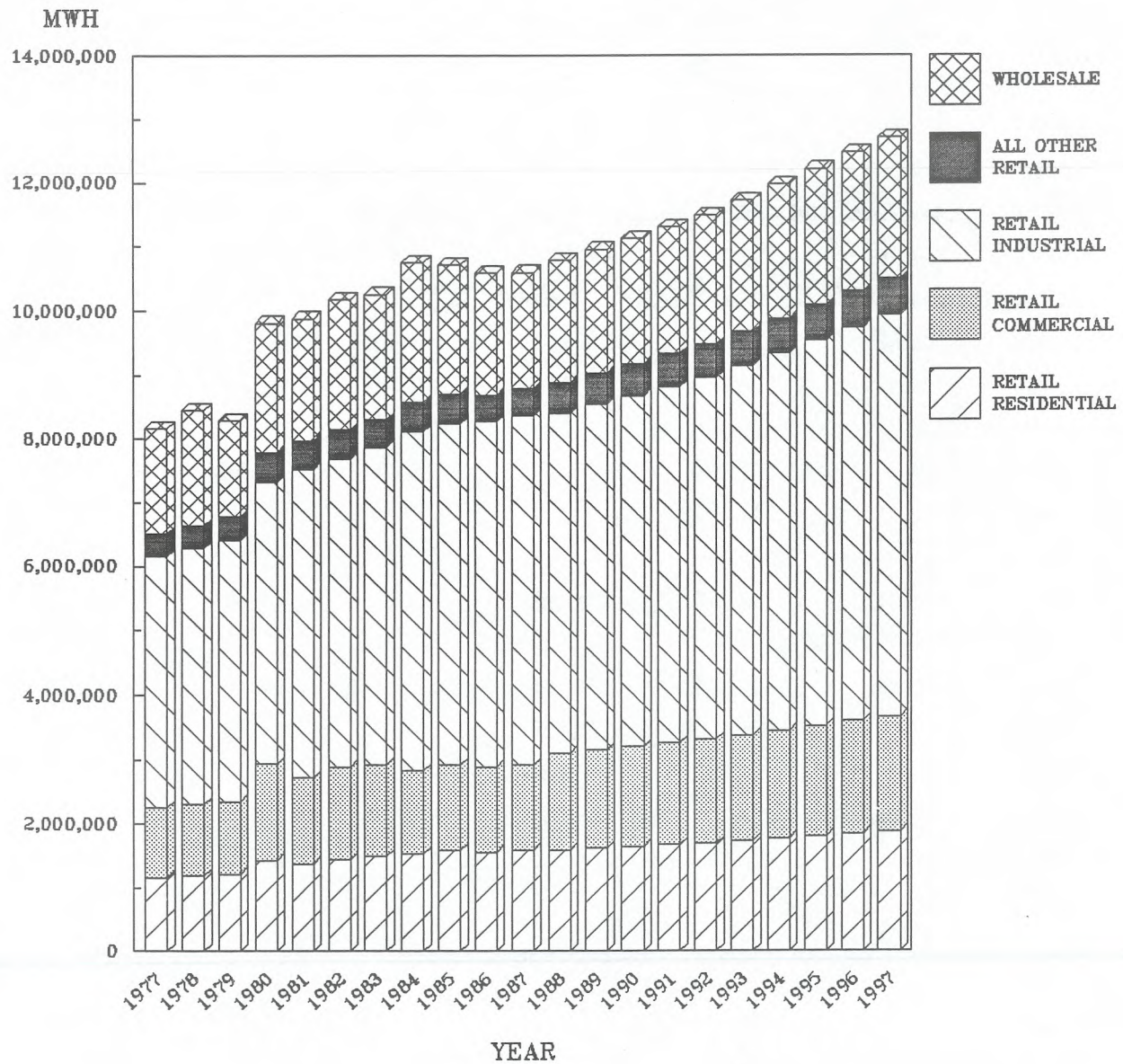
SOURCE: TABLE 7.2A

TABLE 7.2A
Annual Sales by Sector
Southwestern Public Service Company — Total System
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	1,664,837	1,392,456	4,983,746	470,566	2,181,221	10,692,826
1978	1,706,417	1,427,233	5,108,215	482,318	2,365,994	11,090,177
1979	1,744,389	1,458,993	5,221,886	493,051	2,267,805	11,186,123
1980	1,836,174	1,787,109	5,109,830	620,568	2,864,954	12,218,635
1981	1,777,652	1,639,408	5,572,468	585,860	2,756,159	12,331,547
1982	1,866,497	1,768,316	5,589,250	599,422	3,001,128	12,824,613
1983	2,026,907	1,844,784	6,004,023	599,838	3,034,573	13,510,125
1984	2,119,946	1,745,802	6,607,322	629,824	3,428,224	14,531,118
1985	2,186,214	1,796,600	6,601,987	636,382	3,856,319	15,077,502
1986	2,163,421	1,785,627	6,562,528	584,681	3,573,992	14,670,249
1987	2,205,056	1,770,262	6,669,473	595,133	3,270,003	14,509,927
1988	2,262,045	1,849,083	6,741,422	604,432	3,429,411	14,886,393
1989	2,297,345	1,872,618	6,850,609	617,209	3,472,586	15,110,367
1990	2,334,263	1,896,691	6,960,984	630,087	3,515,805	15,337,830
1991	2,371,950	1,921,479	7,071,845	643,187	3,560,330	15,568,791
1992	2,407,100	1,950,816	7,179,004	655,963	3,641,946	15,834,829
1993	2,458,263	1,992,344	7,331,825	669,925	3,719,473	16,171,830
1994	2,510,524	2,034,788	7,488,019	684,197	3,798,711	16,516,239
1995	2,563,920	2,078,168	7,647,659	698,784	3,879,697	16,868,228
1996	2,618,463	2,122,503	7,810,811	713,692	3,962,465	17,227,934
1997	2,668,845	2,163,494	7,961,658	727,476	4,038,991	17,560,464

Note: Annual sales figures are prior to demand-side adjustments.

FIGURE 7.1B
SOUTHWESTERN PUBLIC SERVICE COMPANY
ANNUAL SALES IN TEXAS BY SECTOR (MWH)



SOURCE: TABLE 7.2B

TABLE 7.2B
Annual Sales by Sector
Southwestern Public Service Company — Texas Only
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	1,168,652	1,088,749	3,895,762	355,541	1,657,760	8,166,463
1978	1,192,553	1,111,016	3,975,438	362,812	1,806,465	8,448,284
1979	1,216,943	1,133,739	4,056,743	370,232	1,515,156	8,292,814
1980	1,435,533	1,495,063	4,385,155	481,552	2,009,372	9,806,675
1981	1,382,199	1,338,003	4,805,373	451,909	1,903,163	9,880,647
1982	1,441,773	1,446,682	4,799,030	454,687	2,032,520	10,174,692
1983	1,497,989	1,431,293	4,940,603	434,438	1,951,938	10,256,261
1984	1,531,608	1,293,704	5,285,234	463,010	2,179,293	10,752,849
1985	1,586,629	1,331,817	5,322,178	471,082	2,006,823	10,718,529
1986	1,563,815	1,324,276	5,384,074	422,933	1,899,035	10,594,133
1987	1,594,231	1,322,011	5,444,773	432,629	1,809,085	10,602,729
1988	1,596,243	1,507,848	5,296,770	490,431	1,895,109	10,786,401
1989	1,622,170	1,532,506	5,383,317	498,346	1,921,962	10,958,301
1990	1,648,358	1,557,404	5,470,732	506,345	1,949,288	11,132,127
1991	1,674,712	1,582,436	5,558,626	514,426	1,977,057	11,307,257
1992	1,700,723	1,606,731	5,644,402	521,999	2,010,095	11,483,950
1993	1,736,871	1,640,934	5,764,555	533,111	2,048,549	11,724,020
1994	1,773,794	1,675,892	5,887,361	544,466	2,087,851	11,969,364
1995	1,811,519	1,711,621	6,012,876	556,075	2,128,020	12,220,111
1996	1,850,053	1,748,136	6,141,152	567,938	2,169,073	12,476,352
1997	1,885,647	1,781,897	6,259,754	578,907	2,207,030	12,713,235

Note: Annual sales figures are prior to demand-side adjustments.

The wholesale sector in Texas is predicted to display an average annual compound growth rate of 2 percent over the forecast period. This figure is up from the 0.9 percent seen during the period from 1977 through 1987. In 1987, 1,809,085 MWH was purchased at the wholesale level in Texas from the Company. Wholesale sales have been steadily increasing since 1977 and this trend is expected to continue into 1997. In 1977 the wholesale sector was the second largest consumer of power, purchasing 19 percent of the total power sold in Texas. In 1987 this percentage was reduced to 17 percent. By 1997, the portion of sales attributed to wholesale customers is projected to be slightly higher than in 1987.

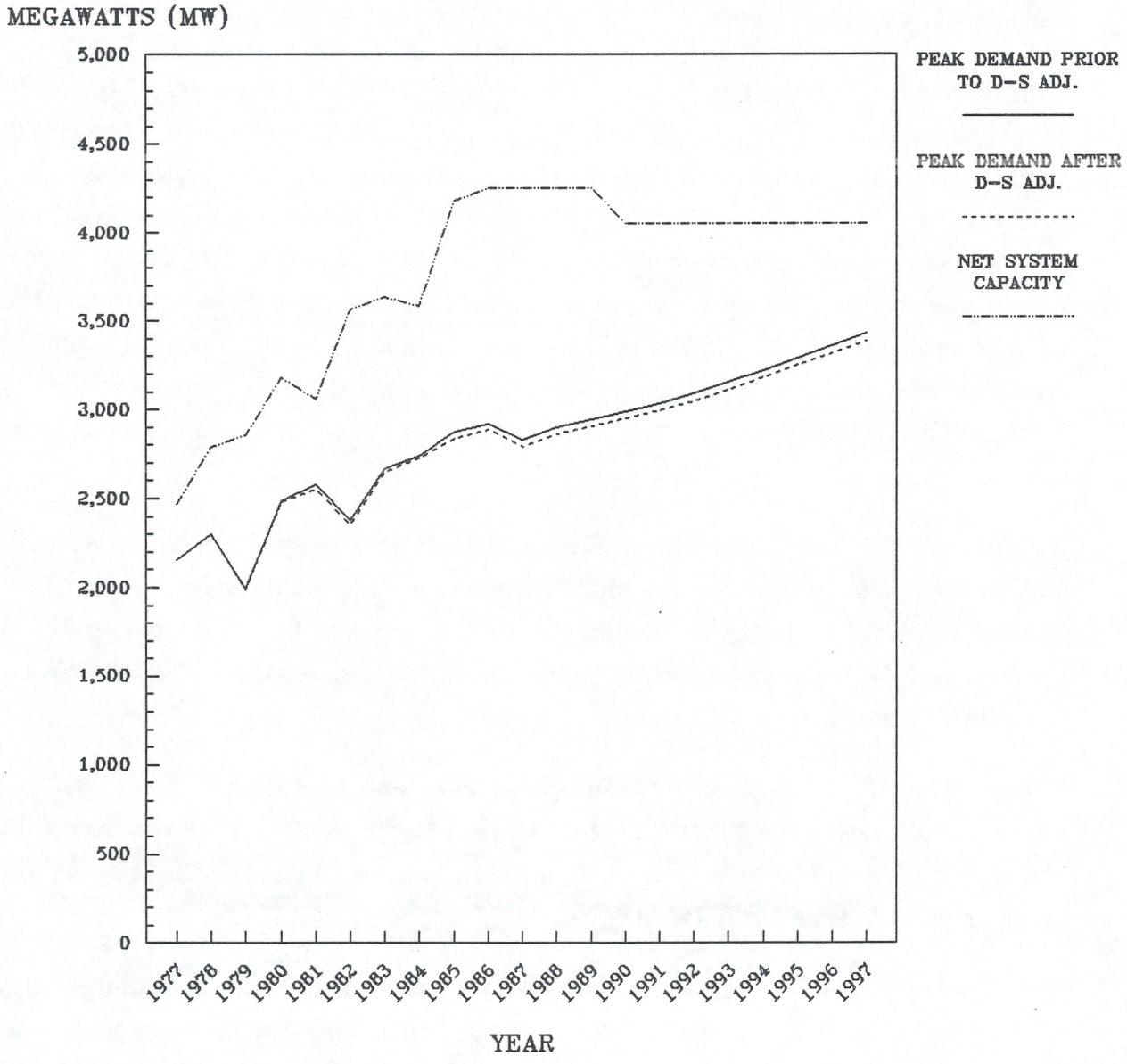
Peak Demand. Over the period from 1977 through 1987, SPS experienced 2.6 percent annual growth in peak demand for its total system. Figure 7.2, *Net System Capacity and Peak Demand,* shows that peak demand after adjustments rose from 2,155 MW in the base year to 2,790 MW in 1987. The Texas share of the SPS system contributed 2,017 MW in 1980, and 2,071 MW in 1987. These figures represent a 0.4 percent annual growth rate for the Texas portion of the total system for this seven-year period. The utility expects growth from 1987 to 1997 to occur at about 2 percent annually in both the total and Texas share of the system. SPS anticipates a peak demand after adjustments of 3,383 MW for its total system by 1997, with 2,511 MW of this total allocated to the Texas system.

In August 1987, the Company experienced its system peak of 2,790 MW, after adjustments. The coincident peak of industrial sector accounted for 36 percent of the total system peak demand; the wholesale sector, 28 percent; the residential sector, 21 percent; and the commercial sector, 15 percent. These percentages are applicable for both the total and Texas systems.

The sector with the highest 1987 non-coincident peak allocated to Texas was the industrial sector, with 978 MW. The second highest non-coincident peak was that of the residential sector at 616 MW. The wholesale sector reached a peak of 582 MW, and the commercial sector peaked at 352 MW.

Demand-Side Adjustments. On the demand side, SPS has stated that its primary energy efficiency goal is to increase the load factor. As a means to this end, the Company offers four end-user conservation programs to its customers. Two of these programs are incentive-based programs which encourage both the initial and replacement installation

FIGURE 7.2
SOUTHWESTERN PUBLIC SERVICE COMPANY
NET SYSTEM CAPACITY AND PEAK DEMAND



of high-efficiency appliances and heat pumps. SPS also conducts energy audits upon request, for interested customers.

SPS reported that its various conservation and load management efforts resulted in a 37-MW reduction in peak demand in 1987. Adjustments to the peak demand of the utility have grown from 5 MW in 1978 to the 37 MW reported for 1987. By 1997 SPS anticipates a reduction in peak demand of 45 MW due to conservation and load management. The effects of the utility's adjustments may be seen in Figure 7.2 as the difference between Peak Demand Before Adjustments and Peak Demand After Adjustments.

7.2 CAPACITY PLAN

Efficiency Improvements to Supply. With respect to supply efficiency, SPS has established three primary goals: to improve the heat rates, reduce line losses, and increase plant efficiency and reliability. In an effort to achieve these goals, the Company has implemented 14 supply efficiency programs. Eleven of these programs focus on improvements in the performance of electric power production. Three programs concentrate on the reduction of transmission losses.

Current Installed Capacity. In 1987, SPS had the installed capacity of about 4,051 MW of electricity as shown in Table 7.3, *Installed Capacity by Fuel Type*, 53 percent coal-fueled and 46 percent gas-fueled. The remainder of the installed capacity is fueled by oil.

At year-end 1987, SPS reported a production plant balance of about $1.1 billion and a net book cost of $0.9 billion.

Net System Capacity. As shown in Table 7.4, *Net System Capacity and Reserve Margins*, the 1977 net system capacity for the total system was 2,469 MW, with 2.102 MW physically located within Texas and an allocated portion of this capacity of approximately 1,872 MW to serve Texas load. SPS maintained a 14.6 percent reserve margin in that year. The reserve margin is represented in Figure 7.2 as the difference between peak load after demand-side adjustments and net system capacity. By 1987, net capacity had grown to 4,251 MW for the total system, of which 3570 is located in Texas and 3,100 MW allocated to Texas, depicting an annual capacity growth of 5.6 percent. The reserve margin for 1987 was calculated by SPS to be 52.4 percent. Southwestern is projecting no

TABLE 7.3
Installed Capacity by Fuel Type
Southwestern Public Service Company
(MW)

Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	2,086	317	0	0	0	0	2,403
1978	2,086	634	0	0	0	0	2,720
1979	2,116	671	0	0	0	0	2,787
1980	2,104	1,009	0	0	0	0	3,113
1981	1,951	1,044	0	0	0	0	2,995
1982	1,946	1,552	0	0	0	0	3,498
1983	2,065	1,568	0	0	0	0	3,633
1984	2,018	1,568	0	0	0	0	3,586
1985	1,905	2,076	0	0	0	0	3,981
1986	1,905	2,146	0	0	0	0	4,051
1987	1,905	2,146	0	0	0	0	4,051
1988	1,905	2,146	0	0	0	0	4,051
1989	1,905	2,146	0	0	0	0	4,051
1990	1,905	2,146	0	0	0	0	4,051
1991	1,905	2,146	0	0	0	0	4,051
1992	1,905	2,146	0	0	0	0	4,051
1993	1,905	2,146	0	0	0	0	4,051
1994	1,905	2,146	0	0	0	0	4,051
1995	1,905	2,146	0	0	0	0	4,051
1996	1,905	2,146	0	0	0	0	4,051
1997	1,905	2,146	0	0	0	0	4,051

Note: Alternate sources do not include cogeneration.

TABLE 7.4
Net System Capacity and Reserve Margins
Southwestern Public Service Company
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	2,155	2,155	2,403	66	0	2,469	14.6
1978	2,303	2,298	2,720	66	0	2,786	21.2
1979	1,992	1,987	2,787	66	0	2,853	43.6
1980	2,487	2,482	3,113	66	0	3,179	28.1
1981	2,574	2,553	2,995	66	0	3,061	19.9
1982	2,378	2,355	3,498	66	0	3,564	51.3
1983	2,664	2,648	3,633	0	0	3,633	37.2
1984	2,736	2,722	3,586	0	0	3,586	31.7
1985	2,871	2,837	3,981	200	0	4,181	47.4
1986	2,919	2,883	4,051	200	0	4,251	47.5
1987	2,827	2,790	4,051	200	0	4,251	52.3
1988	2,900	2,860	4,051	200	0	4,251	48.6
1989	2,945	2,904	4,051	200	0	4,251	46.4
1990	2,989	2,948	4,051	0	0	4,051	37.4
1991	3,035	2,993	4,051	0	0	4,051	35.3
1992	3,087	3,045	4,051	0	0	4,051	33.1
1993	3,154	3,111	4,051	0	0	4,051	30.2
1994	3,222	3,179	4,051	0	0	4,051	27.4
1995	3,292	3,248	4,051	0	0	4,051	24.7
1996	3,362	3,318	4,051	0	0	4,051	22.1
1997	3,428	3,383	4,051	0	0	4,051	19.7

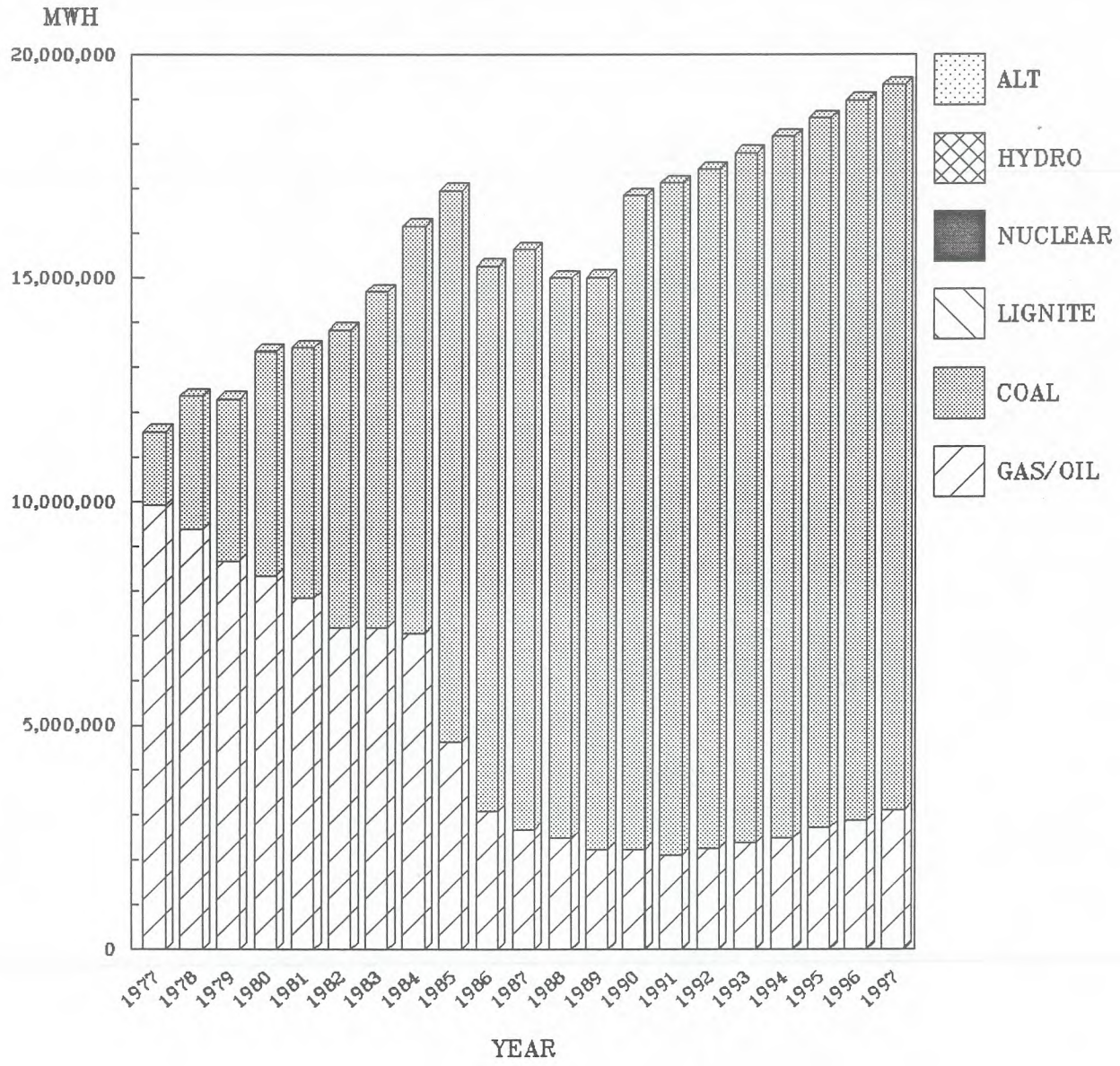
change in installed capacity over the forecast period. They are, however, expecting to discontinue a 200 MW off-system firm purchase and to increase off-system interruptible sales to 130 MW in 1997. The net system capacity of 4,051 MW in 1997 has a corresponding Texas allocated portion of capacity of 2,910 MW. The reserve margin for 1997 is projected to be 20 percent.

Net Generation. As shown in Figure 7.3, *Net Generation by Fuel Type*, in 1977 SPS generated 84 percent of its electricity using gas. In 1976 the utility began using coal, and coal accounted for 14 percent of the total in 1977. Over the 10-year period ending in 1987, with the installation of additional capacity which used coal and the retirement of gas fired facilities, these percentages showed a marked change. By 1987, 83 percent of the total electricity generated by the utility used coal as the source of energy. Gas generation dropped to 16 percent. This turnabout between gas and coal is the result of a commitment made by the utility in the early 1970s to replace gas-fired generation with coal-fired generation. SPS determined that in the long run, coal-fired generation would be the most cost effective. Furthermore, the utility believes that its rates per KWH are lower with the addition of the coal plants than they would have been had the plants not been built. SPS feels that the fuel cost differential between gas and coal has more than offset the capital costs of the new coal plants. By 1997, the Company expects to generate 84 percent of its electricity using coal, 15 percent using gas, and the remainder using oil. SPS projects its 1997 total net generation to be 19,347,000 MW.

System Expansion. At this time the Company has no plans to augment its system with any additional generating capacity, nor does it have plans for any retirements or deratings. SPS reportedly has fully developed its existing power plant sites.

SPS does have plans for the construction of six major transmission lines. One of these lines will be constructed in New Mexico. The remaining five lines will be located in several counties in Texas. The earliest of these projects began construction in September of 1987 and was scheduled to be completed in January of 1988. It consisted of 7.3 miles of 230 KV line located in Potter County with a total cost of $1,911,213. A two-mile stretch of 115 KV line located in Randall County was due to begin construction in February of 1988 and be completed in May of that same year. This project will cost the Company an estimated $284,911. In Yoakum County 3.2 miles of 230 KV line will be under construction from March, 1990 to May, 1990 with a total cost of $418,816. The fourth transmission line project located in Texas will consist of 39 miles of 230 KV line in Lamb and Lubbock Counties. Construction is expected to begin in September of 1989

FIGURE 7.3
SOUTHWESTERN PUBLIC SERVICE COMPANY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

and be completed in May, 1990 with a total estimated cost of $2,700,000. In September, 1990, SPS will begin construction of 53 miles of 230 KV transmission line located in Lubbock, Hockley, Terry, and Yoakum Counties. This project is due to be completed in May of 1991 with a total cost of $4,505,000.

A major Southwestern construction project not reflected in the supplied data at the end of 1987 is the repowering of Nichols Station Unit 3. Since the filing of this report, SPS has been selected to receive $52 million in federal financing to further develop technology to burn coal more cleanly and efficiently at power plants. The funds will be used to repower the 250 MW natural gas-fueled unit with a coal-fuel circulating fluidized bed boiler. The construction is to begin in late 1989 with operations beginning in 1993. The total cost of this project is estimated at $135.5 million.

The statistical data included herein does not reflect the shift that will occur in the Company's fuel mix. To correct the report to the project announcement date would unduly delay the completion of the report.

CHAPTER EIGHT

SOUTHWESTERN ELECTRIC POWER COMPANY

Southwestern Electric Power Company is a subsidiary of Central and South West Corporation, Inc., a holding company that controls SWEPCO, CPL, WTU, and Public Service Company of Oklahoma. SWEPCO is a public utility engaged in generating, purchasing, transmitting, and distributing electricity in portions of northeastern Texas, northwestern Louisiana, and western Arkansas. The Company also owns some transmission facilities in Oklahoma, but serves no customers there. SWEPCO functions as a member of the Southwest Power Pool (SPP) electric reliability council.

SWEPCO is an investor-owned utility. Its revenues for 1987 totaled $714,652,000, while total assets as of December 31, 1987 were $1,939,237,000. The Company's capital structure was comprised of 47 percent common equity, 7 percent preferred stock, and 46 percent long-term debt.

SWEPCO's 1987 peak demand of 3,085 MW occurred in August. The Texas portion of that peak demand amounted to 1,542 MW. The winter peak, which occurred in January of 1987, was approximately 350 MW less than the summer peak. The utility projected their 1987 aggregate sales in Texas to be 7,191,916 MWH. SWEPCO has an installed capacity of about 4,499 MW. In 1987, about 62 percent of the total electricity generated by the utility used coal as the primary fuel.

Unless otherwise noted in the following analysis, totals and percentages refer to the portion of the SWEPCO system allocated to Texas rather than the entire system.

8.1 DEMAND FORECAST

Forecasting Methodology. In formulating its forecasts, SWEPCO examines historical trends, usually the most recent five-year period. After fitting a basic trendline to these data points, the Company subjectively adjusts this forecast to allow for factors such as performance in the economy, new industrial loads, rate changes, and conservation.

Number of Customers. As shown in Table 8.1B, *Number of Customers in Texas by Sector*, in 1987 SWEPCO provided electric service to 121,327 residential customers in Texas. The historical data for the period from 1977 through 1987 reflect an annual growth rate

of 1.7 percent for this class of customers. SWEPCO expects an annual growth rate of 2.8 percent through 1997. In Texas, the Company served 20,377 commercial customers in 1987. Both the historical and projected growth rates for this sector are 3 percent per annum. The industrial sector, however, exhibits a somewhat different pattern of growth. Within this class, the number of customers declined at a rate of 0.9 percent annually from 1977 to 1987. Currently, SWEPCO serves 2,586 industrial customers in Texas. This number is expected to decline at an annual rate of less than 1 percent over the period from 1987 through 1997. See Table 8.1A for the number of customers in the total SWEPCO system.

Total Sales. Figure 8.1B and Table 8.2B, *Annual Sales in Texas by Sector*, show that sales to residential customers in 1987 comprised 20 percent of the aggregate sales. In 1987, the residential sector purchased 1,428,936 MWH of electricity. The utility projected an annual compound growth rate for sales to the residential sector of 2.7 percent, down slightly from the 3.1 percent experienced for the years 1977 through 1987. Comparable data for the total SWEPCO system is shown in Figure 8.1A and Table 8.2A.

Historically, the commercial sector in Texas exhibited an average compound growth rate of 5.3 percent annually. SWEPCO does not expect this rate to carry over into the future. They are predicting a 2.6 percent annual growth rate for the period from 1987 through 1997. Sales to commercial customers totaled 1,126,799 MWH in 1987, representing 16 percent of the total sales in Texas.

The industrial class is the primary consumer of power in the SWEPCO service area, having purchased 40.5 percent of the total electricity sold in Texas in 1987. The total industrial sales in that year amounted to 2,918,195 MWH. As with the commercial sector, sales to the industrial sector demonstrated a 5.3 percent rate of growth over the past decade. SWEPCO has a less optimistic outlook for the future, projecting a 2.1 percent annual growth rate compounded over the next ten years in Texas. The utility anticipates only a small decrease in the industrial class' contribution to the total sales, down to 38.6 percent by 1997.

The remaining retail sales are composed primarily of sales to municipalities for street lighting and other purposes. These sales amounted to 147,555 MWH in 1987, or 2 percent of the total sales in Texas for that year. The growth rate for this class is expected to decline from 3.6 percent per year over the historical period to 2.9 percent per year over the period from 1987 through 1997.

TABLE 8.1A
Number of customer by Sector
Southwestern Electric Power Company — Total System

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	267,069	33,553	6,844	1,997	20
1978	274,935	33,986	6,982	2,052	15
1979	281,709	34,910	7,068	2,133	15
1980	286,861	35,780	7,260	2,192	15
1981	293,146	36,925	7,113	2,322	16
1982	298,079	37,869	6,989	2,380	16
1983	304,457	39,151	6,794	2,388	18
1984	310,912	40,645	6,597	2,431	21
1985	313,336	42,061	6,565	2,439	22
1986	313,951	42,724	6,200	2,504	23
1987	314,414	43,702	6,130	2,547	23
1988	318,345	45,014	6,099	2,599	21
1989	326,304	46,365	6,068	2,652	21
1990	336,094	47,756	6,037	2,706	21
1991	346,177	49,189	6,006	2,761	21
1992	356,563	50,665	5,975	2,817	21
1993	367,260	52,185	5,945	3,174	21
1994	378,278	53,751	5,915	2,932	21
1995	389,627	55,364	5,885	2,992	21
1996	401,316	57,025	5,855	3,053	21
1997	413,356	58,736	5,825	3,115	21

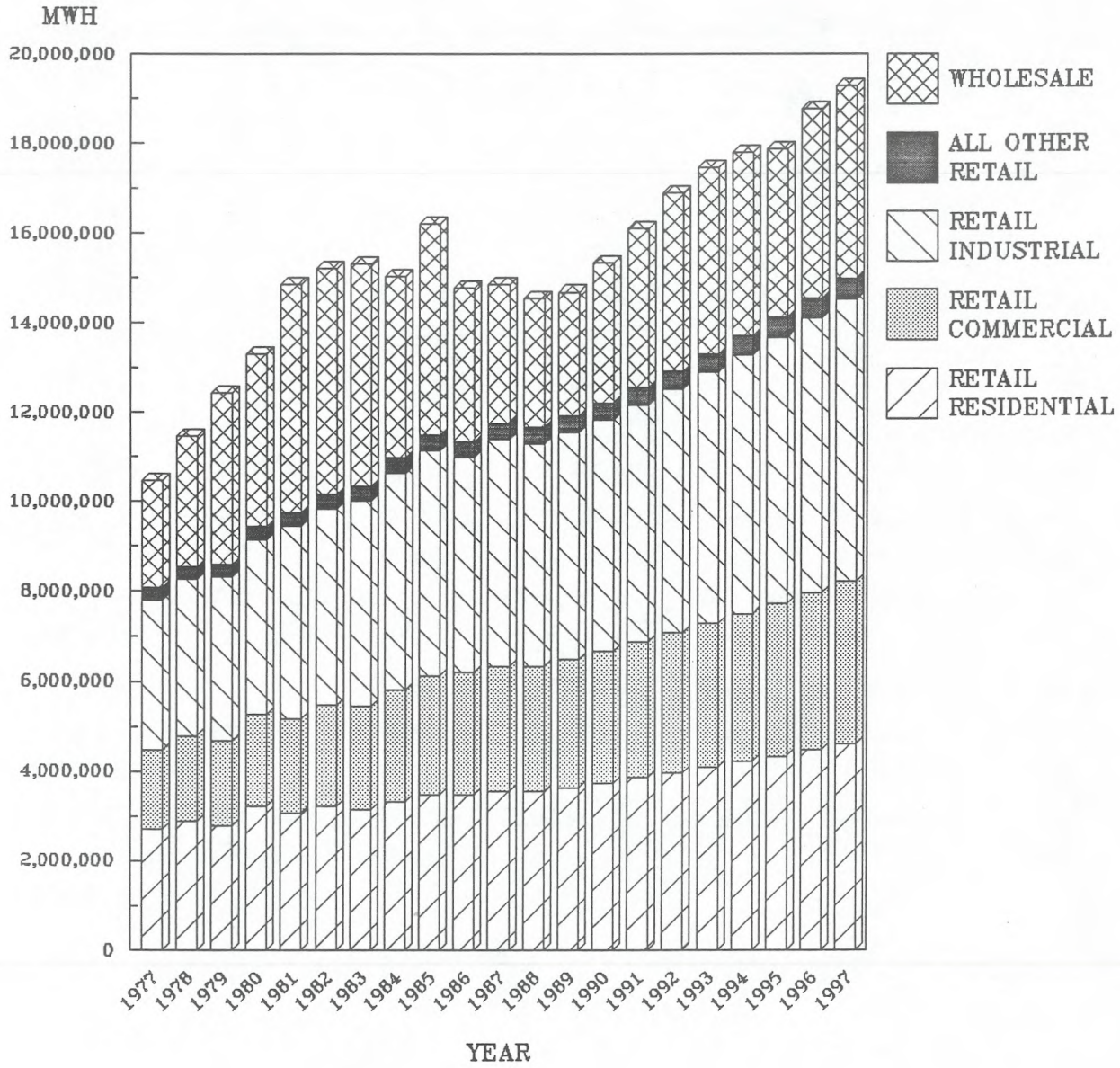
Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

TABLE 8.1B
Number of customer by Sector
Southwestern Electric Power Company — Texas Only

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	102,811	15,098	2,832	718	6
1978	106,412	15,479	2,863	739	6
1979	109,590	15,948	2,952	779	6
1980	112,433	16,486	3,021	814	6
1981	115,114	17,068	3,019	820	7
1982	117,149	17,675	3,009	849	7
1983	119,530	18,262	2,927	840	7
1984	120,767	18,960	2,726	845	9
1985	121,799	19,498	2,688	837	9
1986	121,481	19,757	2,576	851	10
1987	121,327	20,377	2,586	860	9
1988	122,844	20,989	2,573	878	9
1989	125,915	21,619	2,560	896	9
1990	129,693	22,268	2,547	915	9
1991	133,584	22,937	2,534	934	9
1992	137,592	23,626	2,521	953	9
1993	141,720	24,335	2,508	974	9
1994	145,972	25,066	2,495	995	9
1995	150,352	25,818	2,482	1,016	9
1996	154,863	26,593	2,469	1,038	9
1997	159,509	27,391	2,456	1,060	9

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 8.1A
SOUTHWESTERN ELECTRIC POWER COMPANY
TOTAL ANNUAL SALES BY SECTOR (MWH)



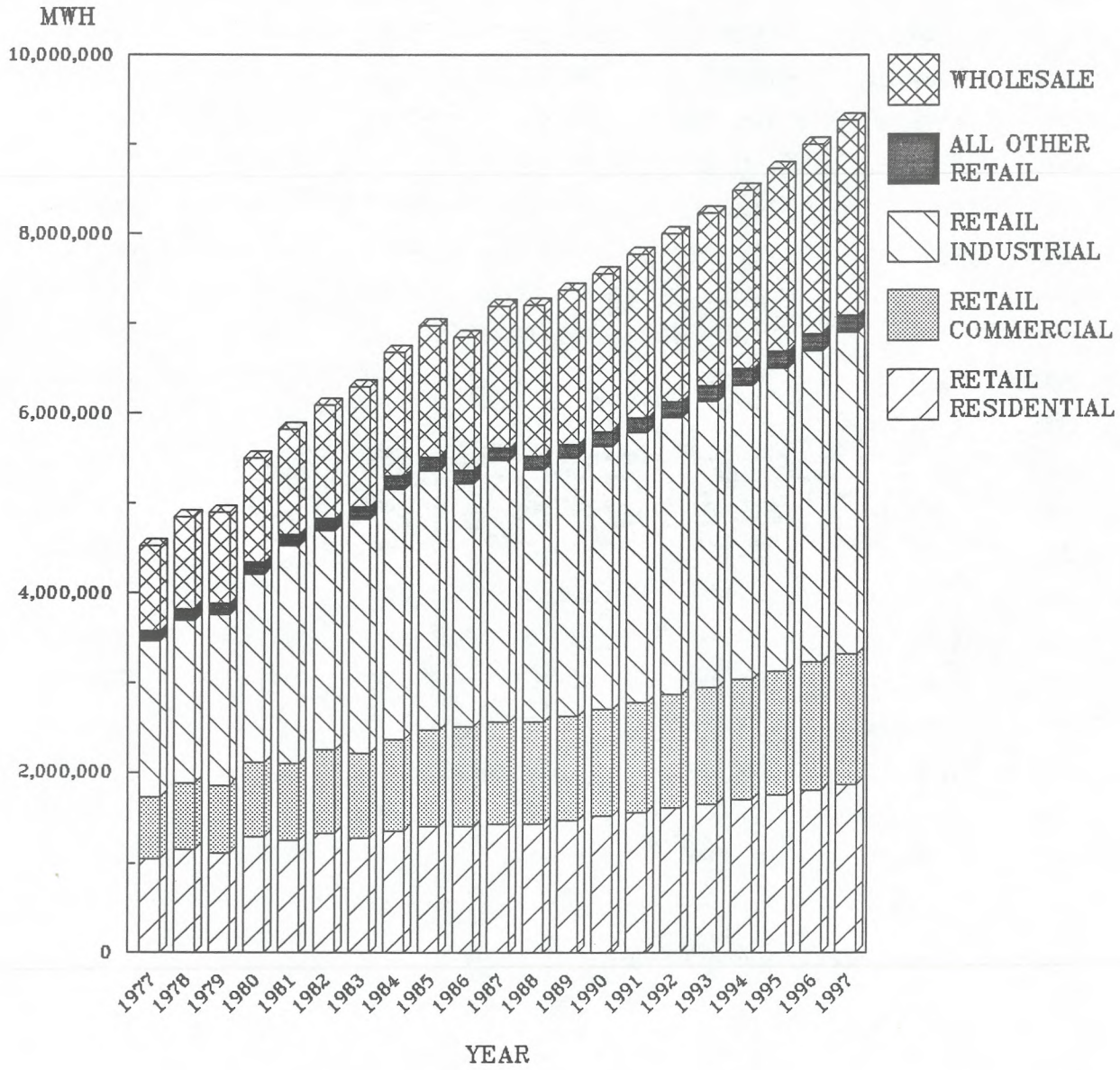
SOURCE: TABLE 8.2A

TABLE 8.2A
Annual Sales by Sector
Southwestern Electric Power Company — Total System
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	2,697,444	1,789,406	3,311,770	266,301	2,399,423	10,464,344
1978	2,897,967	1,902,912	3,463,476	274,153	2,912,368	11,450,876
1979	2,782,229	1,908,504	3,622,248	285,238	3,842,735	12,440,954
1980	3,217,160	2,053,027	3,859,626	299,287	3,885,672	13,314,772
1981	3,070,573	2,103,505	4,261,652	303,354	5,118,315	14,857,399
1982	3,224,665	2,258,115	4,340,691	321,960	5,065,862	15,211,293
1983	3,149,545	2,316,591	4,531,631	329,571	4,996,592	15,323,930
1984	3,325,460	2,485,768	4,811,913	349,198	4,088,745	15,061,084
1985	3,475,815	2,646,621	4,998,881	358,540	4,724,074	16,203,931
1986	3,477,613	2,712,303	4,795,843	356,227	3,421,041	14,763,027
1987	3,555,027	2,776,641	5,051,159	354,559	3,110,758	14,848,144
1988	3,546,000	2,776,000	4,968,000	373,000	2,882,733	14,545,733
1989	3,635,000	2,845,000	5,067,000	380,000	2,755,000	14,682,000
1990	3,744,000	2,917,000	5,169,000	390,000	3,117,000	15,337,000
1991	3,856,000	3,004,000	5,298,000	400,000	3,546,000	16,104,000
1992	3,972,000	3,094,000	5,457,000	411,000	3,974,000	16,908,000
1993	4,091,000	3,187,000	5,620,000	422,000	4,160,000	17,480,000
1994	4,214,000	3,283,000	5,789,000	433,000	4,083,000	17,802,000
1995	4,340,000	3,381,000	5,963,000	444,000	3,743,000	17,871,000
1996	4,471,000	3,483,000	6,142,000	456,000	4,229,000	18,781,000
1997	4,605,000	3,587,000	6,326,000	469,000	4,301,000	19,288,000

Note: Annual sales figures are prior to demand-side adjustments.

FIGURE 8.1B
SOUTHWESTERN ELECTRIC POWER COMPANY
ANNUAL SALES IN TEXAS BY SECTOR (MWH)



SOURCE: TABLE 8.2B

TABLE 8.2B
Annual Sales by Sector
Southwestern Electric Power Company — Texas Only
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	1,050,391	672,806	1,742,866	103,973	948,598	4,518,634
1978	1,146,702	737,924	1,807,155	122,652	1,032,719	4,847,152
1979	1,109,626	752,224	1,897,235	129,060	1,006,440	4,894,585
1980	1,291,989	816,185	2,102,380	137,461	1,146,955	5,494,970
1981	1,252,037	844,648	2,425,697	134,900	1,163,153	5,820,435
1982	1,333,505	923,360	2,438,641	139,463	1,260,551	6,095,520
1983	1,282,086	938,109	2,604,046	140,489	1,336,898	6,301,628
1984	1,360,784	1,010,823	2,780,381	153,222	1,374,725	6,679,935
1985	1,404,669	1,071,901	2,884,412	154,402	1,455,966	6,971,350
1986	1,405,523	1,100,872	2,716,673	150,341	1,477,068	6,850,477
1987	1,428,936	1,126,799	2,918,195	147,555	1,570,431	7,191,916
1988	1,436,000	1,127,000	2,812,000	157,000	1,673,000	7,205,000
1989	1,472,000	1,155,000	2,869,000	160,000	1,715,000	7,371,000
1990	1,516,000	1,184,000	2,926,000	164,000	1,766,000	7,556,000
1991	1,561,000	1,219,000	2,999,000	169,000	1,819,000	7,767,000
1992	1,608,000	1,256,000	3,089,000	173,000	1,874,000	8,000,000
1993	1,657,000	1,293,000	3,182,000	178,000	1,930,000	8,240,000
1994	1,706,000	1,332,000	3,277,000	182,000	1,988,000	8,485,000
1995	1,757,000	1,372,000	3,375,000	187,000	2,048,000	8,739,000
1996	1,810,000	1,413,000	3,477,000	192,000	2,109,000	9,001,000
1997	1,864,000	1,456,000	3,581,000	197,000	2,172,000	9,270,000

Note: Annual sales figures are prior to demand-side adjustments.

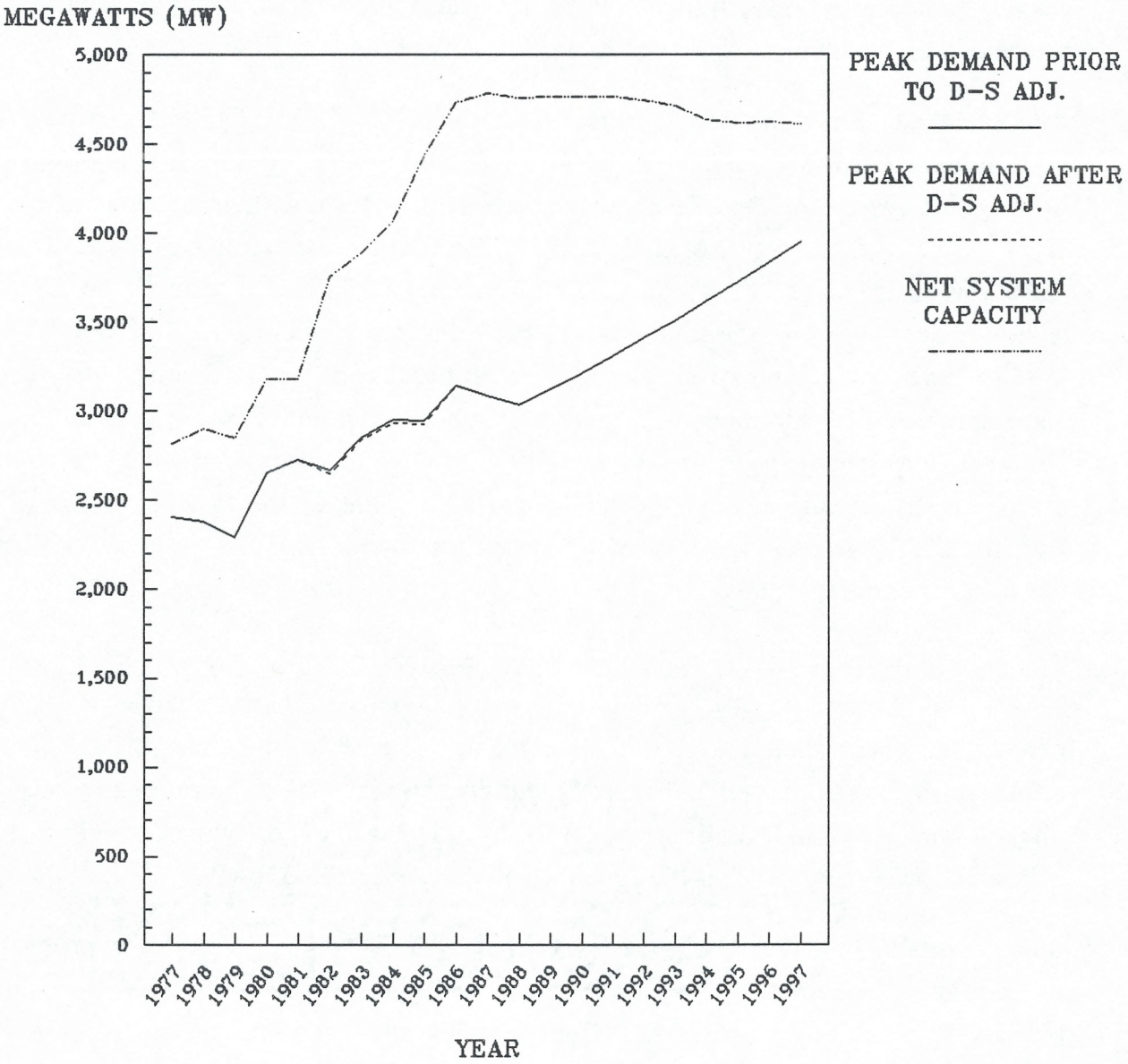
The wholesale sector in Texas is predicted to display the highest annual growth rate. SWEPCO projects sales within this sector to increase at a rate of 3.3 percent per annum through 1997. This figure is down from the 5.2 percent experienced during the period from 1977 through 1987. In 1987, 1,570,431 MWH was purchased wholesale from the company. Wholesale sales have been steadily increasing since 1977 and this trend is expected to continue into 1997. In 1977 the wholesale sector was the third-largest consumer of power, purchasing 21 percent of the total power sold in Texas. This percentage rose to 22 percent in 1987, continuing this class as the second largest customer class. By 1997, the portion of sales attributed to wholesale customers is projected to increase further, to over 23 percent of the total sales in Texas.

Peak Demand. Over the period from 1977 through 1987 SWEPCO experienced 2.5 percent annual growth in peak demand for their total system. As shown in Figure 8.2, *Net System Capacity and Peak Demand*, the peak demand for the whole system rose from 2,404 MW in the base year to 3,085 in 1987. The share allocated to Texas rose from 1,072 MW in 1977 to 1,542 MW in 1987, representing a 3.7 percent annual growth rate for the Texas portion of the total system. Peak demand actually fell 1.8 percent from 1986 to 1987 for the total system and 17.3 percent for the Texas portion of the system, and is projected to fall another 1.8 percent for both total and Texas system in 1988. However, the utility expects growth from 1988 to 1997 to occur at about 2.9 percent compounded annually in both the total and Texas share of the system. SWEPCO anticipates a peak demand of 3,950 MW for their total system by 1997, with 1,973 MW of this total allocated to Texas.

The coincident peak of the residential sector accounted for 38 percent of the total system peak demand in 1987, the industrial sector 23 percent, the commercial sector 20 percent, and the wholesale sector, 18 percent. The sector with the highest non-coincident peak was the residential sector with 943 MW in 1987. The residential sector was followed by the industrial sector at 552 MW. The wholesale sector reached a non-coincident peak of 398 MW in 1987 and the commercial sector, 331 MW.

Adjustments to Demand. SWEPCO states that its energy efficiency goal is to promote the wise use of electricity by its customers. In an effort to achieve this goal the utility offers several end-user programs. One provides advice to improve energy use in residential dwellings through better insulation, efficient heating and cooling, and efficient water heating equipment. The utility conducts energy audits. In addition, an

FIGURE 8.2
SOUTHWESTERN ELECTRIC POWER COMPANY
NET SYSTEM CAPACITY AND PEAK DEMAND



D-S ADJ. is Demand-Side Adjustments.

interruptible load program is offered. SWEPCO does not adjust its future peak demand forecast for the effects of its demand-side programs.

8.2 CAPACITY PLAN

Efficiency Improvements to Supply. SWEPCO has two programs to improve the efficiency of its generation. Five programs focus on improvements in transmission and distribution plant and equipment efficiencies.

Another program is designed to assist power producers achieve the status of qualifying facilities. Three cogenerators are connected to the network, and SWEPCO anticipates purchasing 22,000 MWH annually from 1988 through 1996.

Current Installed Capacity. In 1987, SWEPCO had an installed capacity of about 4,499 MW. Table 8.3, *Installed Capacity by Fuel Type*, shows that about 44 percent of this capacity is fueled by coal, and an equal percentage by gas. The remainder of the installed capacity is fueled using either lignite or oil.

SWEPCO reports a production plant balance at year end 1987 of about $1.3 billion with a net book cost of about $1 billion.

Net System Capacity. As shown in Table 8.4 *Net System Capacity and Reserve Margins*, the net system capacity for the total system in 1977 was 2,815 MW, with 1,255 MW attributed to the Texas portion of the system. SWEPCO maintained a 17.1 percent reserve margin in that year. By 1987, net capacity had grown to 4,785 MW for the total system and 2,396 MW for Texas, depicting annual growth rates of 5.5 percent and 6.7 percent, respectively. The utility's reserve margin for 1987 was calculated to be 55.1 percent. SWEPCO is projecting a decline in their net system capacity over the forecast period. The Company expects a 0.4 percent annual decline, resulting in a net system capacity of 4,611 MW for the total system and yielding a systemwide reserve margin of 16.7 percent for 1997.

Net Generation. As shown in Figure 8.3, *Net Generation by Fuel Type*, in 1977 SWEPCO generated 76 percent of its electricity using gas. The utility began using coal in 1977. Generation using coal accounted for 16 percent of the system total in that year. The remaining 8 percent of electricity was generated using oil. Over the 10-year period to 1987, these percentages showed a marked change. By 1987, 62 percent of the total

TABLE 8.3
Installed Capacity by Fuel Type
Southwestern Electric Power Company
(MW)

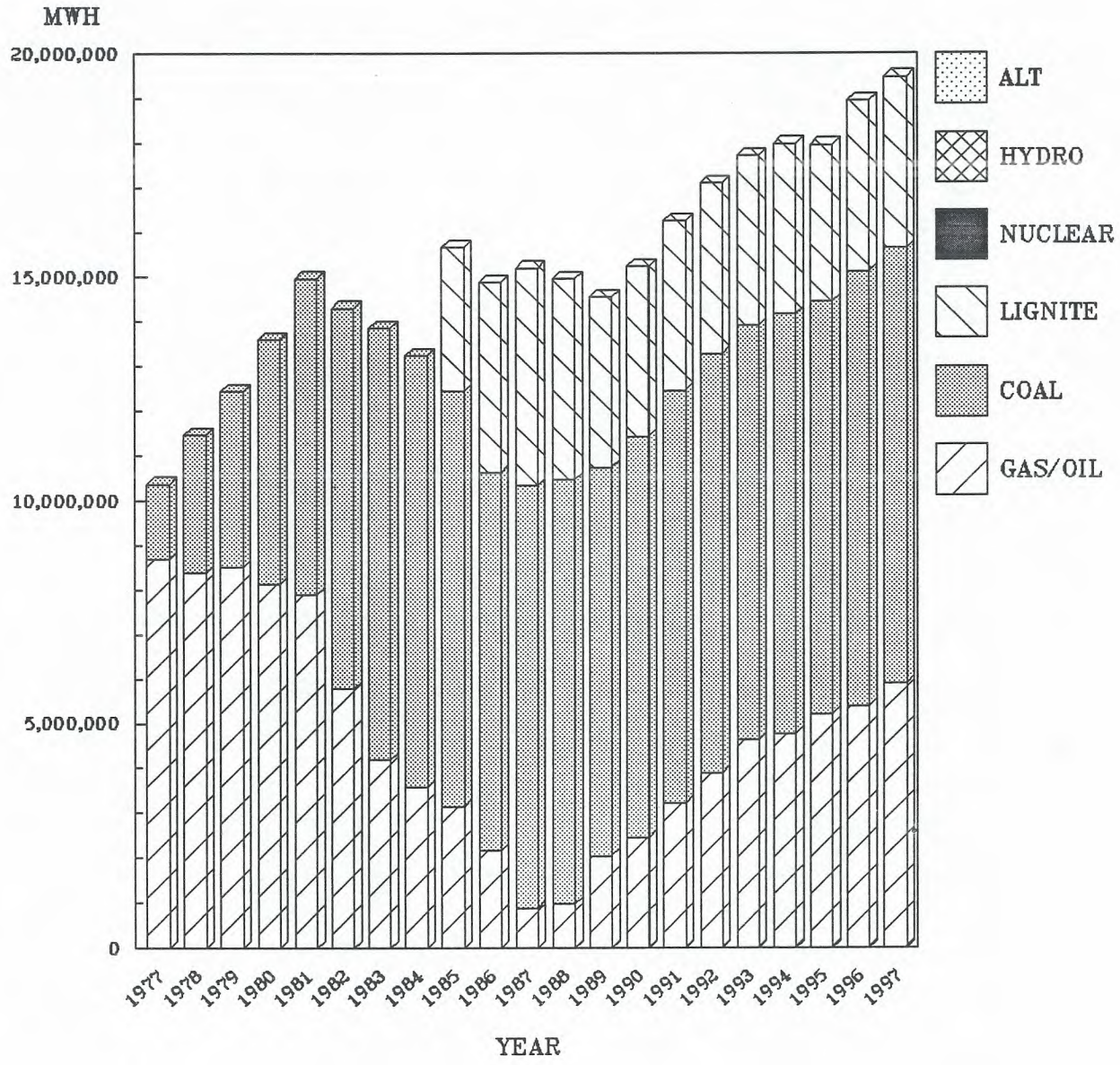
Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	1,943	528	0	0	0	0	2,471
1978	1,943	792	0	0	0	0	2,735
1979	1,895	792	0	0	0	0	2,687
1980	1,895	1,320	0	0	0	0	3,215
1981	1,895	1,320	0	0	0	0	3,215
1982	1,895	1,848	0	0	0	0	3,743
1983	1,895	1,848	0	0	0	0	3,743
1984	1,895	1,848	0	0	0	0	3,743
1985	1,859	1,824	550	0	0	0	4,233
1986	1,859	1,824	807	0	0	0	4,490
1987	1,859	1,824	816	0	0	0	4,499
1988	1,859	1,824	816	0	0	0	4,499
1989	1,859	1,824	816	0	0	0	4,499
1990	1,859	1,824	816	0	0	0	4,499
1991	1,859	1,824	816	0	0	0	4,499
1992	1,859	1,824	816	0	0	0	4,499
1993	1,859	1,824	816	0	0	0	4,499
1994	1,819	1,824	816	0	0	0	4,459
1995	1,819	1,824	816	0	0	0	4,459
1996	1,819	1,824	816	0	0	0	4,459
1997	1,819	1,824	816	0	0	0	4,459

Note: Alternate sources do not include cogeneration.

TABLE 8.4
Net System Capacity and Reserve Margins
Southwestern Electric Power Company
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	2,404.0	2,404.0	2,471.0	344.0	0.0	2,815.0	17.1
1978	2,381.0	2,381.0	2,735.0	262.0	100.0	2,897.0	21.7
1979	2,291.0	2,291.0	2,687.0	262.0	100.0	2,849.0	24.4
1980	2,652.0	2,652.0	3,215.0	162.0	200.0	3,177.0	19.8
1981	2,723.0	2,723.0	3,215.0	322.0	360.0	3,177.0	16.7
1982	2,668.0	2,648.0	3,743.0	362.0	350.0	3,755.0	41.8
1983	2,849.0	2,831.0	3,743.0	401.0	260.0	3,884.0	37.2
1984	2,948.0	2,932.0	3,743.0	324.0	0.0	4,067.0	38.7
1985	2,943.0	2,924.0	4,233.0	260.0	64.0	4,429.0	51.5
1986	3,140.0	3,139.0	4,490.0	293.0	48.0	4,735.0	50.8
1987	3,085.0	3,085.0	4,499.0	286.0	0.0	4,785.0	55.1
1988	3,030.0	3,030.0	4,499.0	268.0	8.0	4,759.0	57.1
1989	3,120.0	3,120.0	4,499.0	268.0	0.0	4,767.0	52.8
1990	3,210.0	3,210.0	4,499.0	268.0	0.0	4,767.0	48.5
1991	3,310.0	3,310.0	4,499.0	268.0	4.0	4,763.0	43.9
1992	3,410.0	3,410.0	4,499.0	268.0	24.0	4,743.0	39.1
1993	3,510.0	3,510.0	4,499.0	268.0	55.0	4,712.0	34.2
1994	3,615.0	3,615.0	4,459.0	268.0	92.0	4,635.0	28.2
1995	3,725.0	3,725.0	4,459.0	268.0	112.0	4,615.0	23.9
1996	3,835.0	3,835.0	4,459.0	268.0	104.0	4,623.0	20.5
1997	3,950.0	3,950.0	4,459.0	268.0	116.0	4,611.0	16.7

FIGURE 8.3
SOUTHWESTERN ELECTRIC POWER COMPANY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

electricity generated by the utility used coal as the source of fuel. Lignite generation contributed 32 percent of the total.

Other sources, such as hydro and biomass, accounted for 0.3 percent. In the years 1987 and 1988 generation using gas was uncharacteristicly low, 5.8 percent in 1987. The reason for this drop in generation using gas is the expiration of a take-or-pay contract during this period. Over the forecast period from 1987 to 1997, it is the intention of SWEPCO to maintain fairly constant levels of generation using coal and lignite. Any projected increase in the total net generation will be allocated to generation using gas. By 1997 the company expects to generate 49.8 percent of its electricity using coal, 30.2 percent using gas, and 19.8 percent using lignite. SWEPCO projects their total net generation to be 19,553,930 MWH in 1997.

System Expansion. At this time the company has no plans to augment their system with any additional generating capacity. They do, however, have plans for a small reduction in their installed capacity. Three oil-fired turbines, Lone Star 2, Lone Star 3, and Lone Star 4, are scheduled to be retired in December of 1993. This will result in a total 40-MW reduction in SWEPCO's installed capacity.

The Company recently added two plants to its system. Pirkey Unit 1, located in Harrison County, Texas, began commercial operation in December of 1984. This plant added approximately 558 MW to the system. Dolet Hills Unit 1, a lignite-fired plant located in Desoto Parrish, Louisiana, became commercially operational in January 1986. SWEPCO's share of the unit capability is about 257 MW.

SWEPCO could potentially add 1,280 MW of lignite capacity in equal measure at the existing sites of Pirkey and Dolet Hills. Development of additional generating units may be limited by financial, transmission, water and environmental requirements, site layout, and fuel supply. A site specific study may be required to determine the best technology and size.

Included in SWEPCO's construction work in progress are three major transmission line projects. Two of these lines are being constructed in Arkansas and Oklahoma. The third transmission line construction project is located in Titus County, Texas. This particular project consists of 16 miles of 345 KV line. The project was scheduled to begin in January of 1988 and be completed in December of 1989 with a total estimated cost of $5,395,000.

CHAPTER NINE

LOWER COLORADO RIVER AUTHORITY

The Lower Colorado River Authority is a governmental agency created by the legislature of the State of Texas in 1934. The Board of Directors of the LCRA is composed of 15 Directors: twelve from the counties of Blanco, Burnet, Llano, Travis, Bastrop, Fayette, Colorado, Wharton, San Saba and Matagorda, the ten county area which forms the LCRA's boundaries; and three at-large Directors from the counties outside the boundaries which are served with electric power and energy by the LCRA. The Directors are appointed by the Governor of Texas with the advice and consent of the Texas Senate.

The LCRA functions to store, control, conserve, protect, and distribute the waters of the Colorado River in Texas for useful purposes, and to generate, transmit, and sell electric power and energy. The LCRA generates both thermal-electric and hydroelectric power and energy for sale to customers at retail (2 percent of LCRA's total sales) and wholesale (98 percent of LCRA's total sales) in all or part of 52 counties in Central Texas. The LCRA's power and energy is sold at wholesale rates to 33 municipalities, 11 rural electric cooperatives and certain private utility companies, and at retail rates to 70 retail customers in unincorporated areas.

The LCRA's system consists of generators, transformers, substation and transmission line equipment, distribution lines and meters, together with the normal facilities necessary to conduct business as an utility. LCRA operates six dams and reservoirs on the Colorado River and 13 installed hydroelectric generation units with a total net capacity of 241 MW.

LCRA reported a 1987 net generation requirement of approximately 1,514 MW, approximately the same as the previous year. Total sales rose 4.8 percent, however, to 6,900,035 MWH, of which 2.3 percent was sold to retail customers and 97.7 percent to wholesale customers. Installed capacity totaled 1,836 MW. Net generation in 1987 shows a fuel mix of 46.9 percent coal, 42.6 percent gas, 9.8 percent hydro-electric power, and 0.7 percent lignite.

9.1 DEMAND FORECAST

Forecasting Methodology. LCRA's demand forecast consists of four separate components, the Service Area Economic Forecast, the Rate Class Sales Model, the Load Temperature Model, and a Conservation and Load Management Adjustment Model. The Service Area Economic Model, developed by Data Resources, Inc. (DRI), relates the economic performance of three geographic regions of the LCRA service area with that of the national economy using econometric techniques. DRI's base case forecast of the national economy serves as a basis for the base case scenario for the service area. This model serves to generate input for the Rate Class Sales Model. The Rate Class Sales Model calculates annual sales from the output of the Service Area Economic Model, the price of electricity and fuels, appliance saturation, and weather conditions. Regression analysis is used to calculate the relative influence of the inputs. The Load Temperature Model distributes the annual generation requirements from the Rate Class Sales Model across the months of the year and yields peak demand forecasts. The model relates daily generation requirements given average daily temperature. The application of historical monthly load factors yields forecasts of monthly peak demands.

Number of Customers. As shown in Table 9.1, *Number of Customers by Sector*, in 1987, LCRA provided electric service to 16 retail industrial customers and approximately 54 other retail customers. The historical data for the period from 1977 through 1987 shows growth in retail customers through 1985 followed by the sale of LCRA's distribution systems in Kerr, San Saba, and Hayes counties. The number of wholesale customers rose in 1986 from 44. LCRA projects a stable 16 retail industrial and 44 wholesale customers throughout the forecast period.

Total Sales. Miscellaneous retail sales are not projected and 1987 data are unavailable. Figure 9.1, *Annual Sales by Sector*, shows that industrial sales are projected to decline through the forecast period, after a 13.6 percent jump in 1988 to 180,000 MWH. LCRA also sells power off the system, but makes no projection of the non-firm off-system sales. From 1977 through 1986, annual non-firm off-system sales ranged from 51,961 MWH to 863,129 MWH, with 218,082 MWH in 1986.

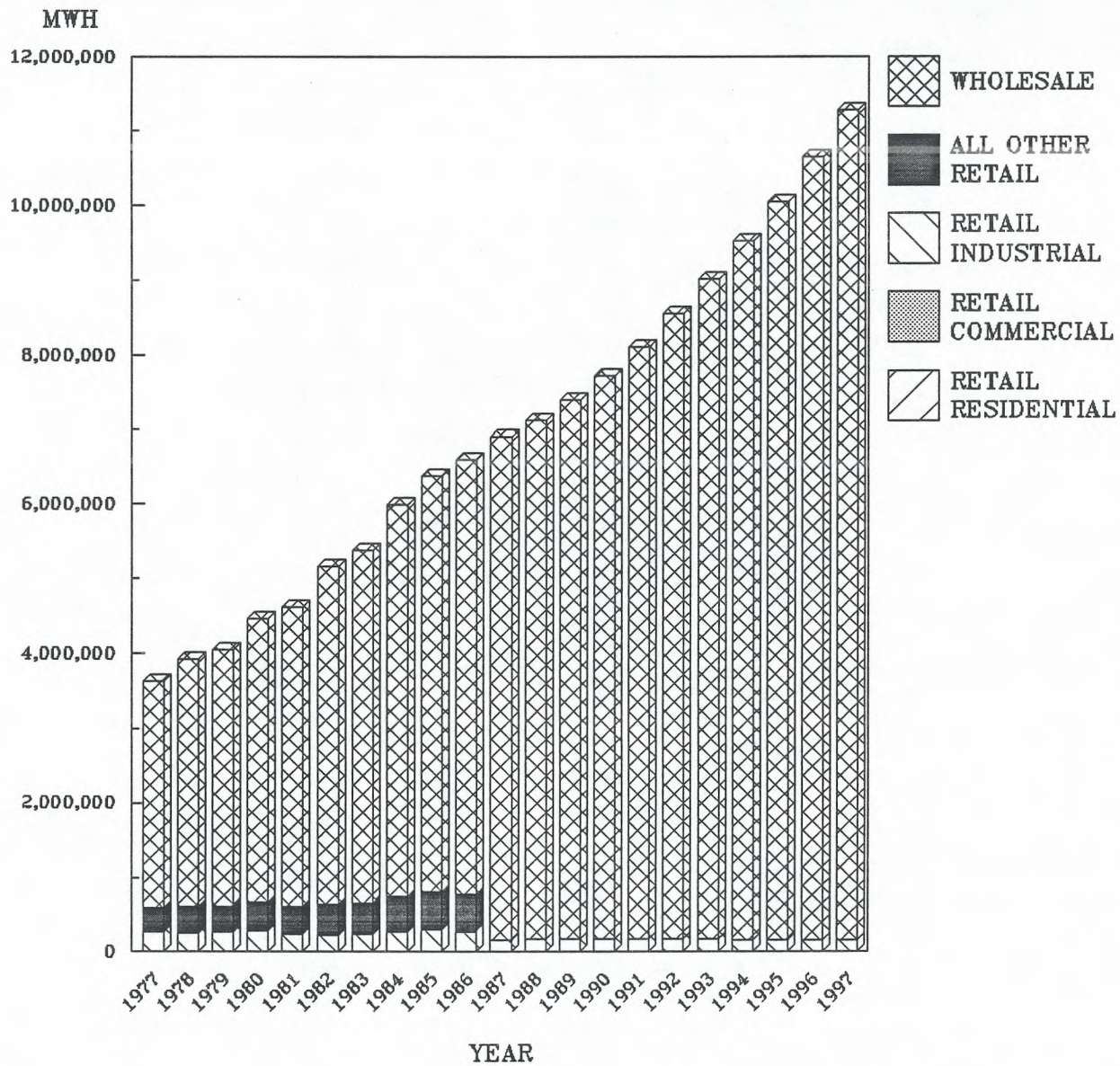
Wholesale sales increase continually from 1977 to 1997 although the annual rate of growth of sales to the wholesale class drops to 5.1 percent from 1987 to 1997 from the rate of 8.1 percent per year over the period 1977 to 1987. To maintain comparability with the forecast period, the historical data have been adjusted to include as wholesale

TABLE 9.1
Number of customer by Sector
Lower Colorado River Authority

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	N/A	N/A	19	19,555	41
1978	N/A	N/A	21	19,944	41
1979	N/A	N/A	19	20,932	41
1980	N/A	N/A	29	21,817	41
1981	N/A	N/A	27	22,801	41
1982	N/A	N/A	28	23,872	41
1983	N/A	N/A	31	25,605	41
1984	N/A	N/A	32	27,286	41
1985	N/A	N/A	32	28,501	41
1986	N/A	N/A	24	17,117	42
1987	N/A	N/A	16	0	44
1988	N/A	N/A	16	0	44
1989	N/A	N/A	16	0	44
1990	N/A	N/A	16	0	44
1991	N/A	N/A	16	0	44
1992	N/A	N/A	16	0	44
1993	N/A	N/A	16	0	44
1994	N/A	N/A	16	0	44
1995	N/A	N/A	16	0	44
1996	N/A	N/A	16	0	44
1997	N/A	N/A	16	0	44

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 9.1
LOWER COLORADO RIVER AUTHORITY
ANNUAL SALES BY SECTOR (MWH)



SOURCE: TABLE 9.2

TABLE 9.2
Annual Sales by Sector
Lower Colorado River Authority
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	0	0	272,988	319,378	3,031,121	3,623,487
1978	0	0	259,649	342,898	3,319,021	3,921,568
1979	0	0	274,530	335,292	3,432,638	4,042,460
1980	0	0	289,456	375,078	3,790,218	4,454,752
1981	0	0	233,290	378,318	4,001,571	4,613,179
1982	0	0	219,113	418,918	4,514,095	5,152,126
1983	0	0	235,078	426,853	4,700,975	5,362,906
1984	0	0	266,219	480,762	5,234,537	5,981,518
1985	0	0	307,643	503,635	5,563,140	6,374,418
1986	0	0	279,028	499,182	5,803,247	6,581,457
1987	0	0	158,512	0	6,741,523	6,900,035
1988	0	0	180,000	0	6,939,000	7,119,000
1989	0	0	179,000	0	7,226,000	7,405,000
1990	0	0	179,000	0	7,551,000	7,730,000
1991	0	0	178,000	0	7,937,000	8,115,000
1992	0	0	176,000	0	8,375,000	8,551,000
1993	0	0	173,000	0	8,852,000	9,025,000
1994	0	0	170,000	0	9,352,000	9,522,000
1995	0	0	168,000	0	9,876,000	10,044,000
1996	0	0	166,000	0	10,479,000	10,645,000
1997	0	0	164,000	0	11,119,000	11,283,000

Note: Annual sales figures are prior to demand-side adjustments.

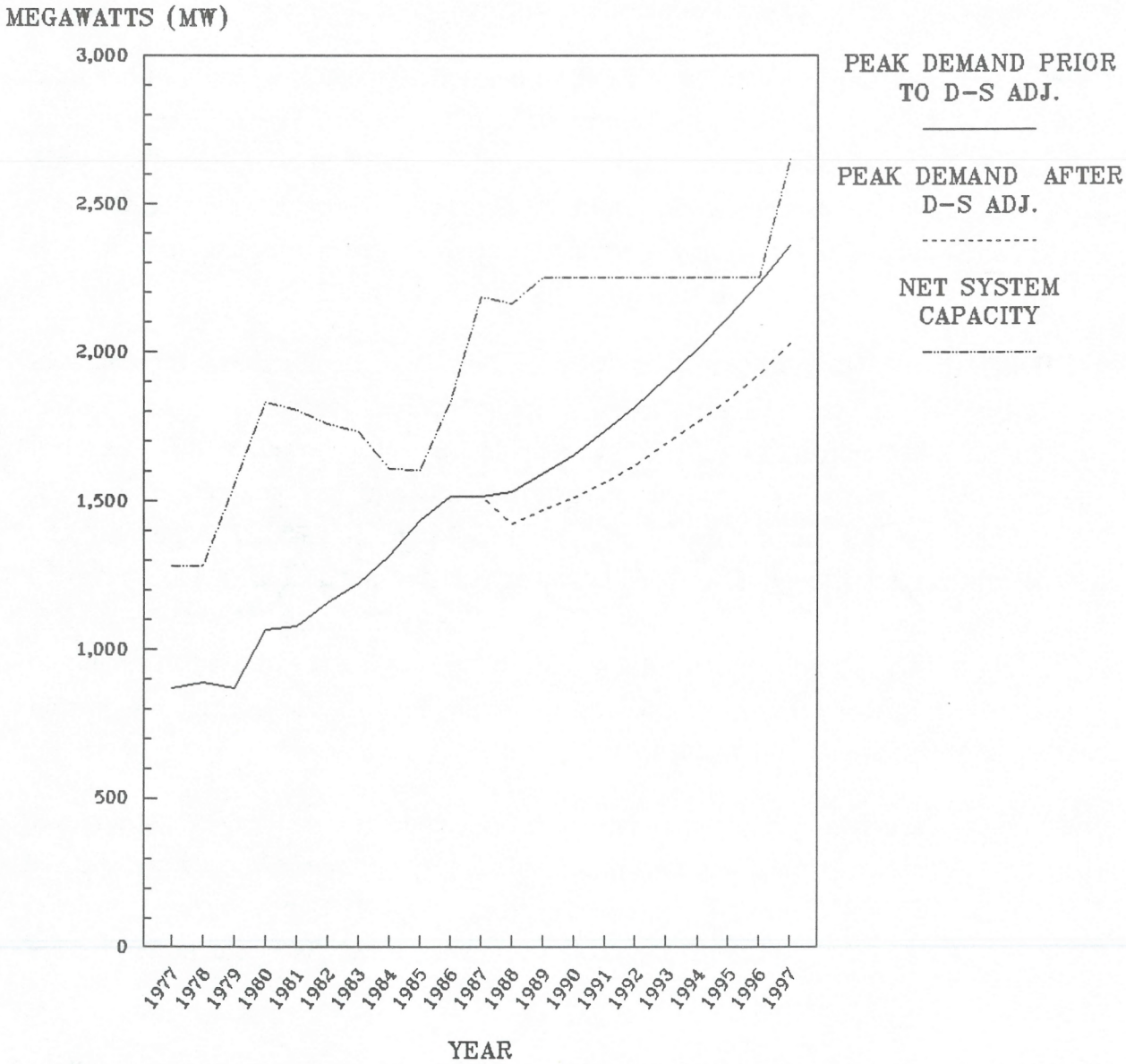
the formerly classified retail sales from the Kerrville, San Marcos, and San Saba districts. Wholesale totals for 1987 of 6,741,523 MWH should increase to 11,119,000 MWH in 1997, according to projections. Similarly, reflecting the fact that most sales of the LCRA are wholesale, the total system sales of 6,900,035 MWH in 1987 will grow to 11,283,000 MWH in 1997.

Peak Demand. Over the period from 1977 through 1987, LCRA experienced 5.7 percent annual growth in peak demand, although Figure 9.2, *Net System Capacity and Peak Demand*, shows summer peak demand down 1.2 MW from 1986 to 1987. The utility expects growth through 1997 to occur at about 4.5 percent annually leading to a summer peak demand of 2,360 MW in 1997. Peak demand for the winter season rose 65 MW from 1986 through 1987 with growth over the forecast period projected at a compound rate of 5.9 percent to reach a 1997 winter peak of 2,475 MW. Whereas peak load for Texas utilities has traditionally occurred during the summer, at some point between 1990 and 1992, the LCRA expects that their winter peak may routinely exceed their summer peak. That is, prior to conservation and load management adjustments, the 1992 winter peak projection of 1,829 MW exceeds the 1992 summer peak projection of 1,816 MW. After accounting for adjustments to demand, the winter peak is projected to exceed the summer peak in 1991.

Demand Side Adjustments. LCRA offers six end-user energy efficiency programs designed to clip peak demand. Two programs limit the simultaneous running of residential central air conditioners and electric water heaters during peak demand periods. Economic incentives are offered to the wholesale customers, their customers, and the dealers who sell energy-efficient air conditioners and heat pumps. Additionally, the LCRA presents a performance-based standard for new home construction which requires the energy consumption to be cut in half compared to typical new homes. Commercial customers are encouraged to replace existing lamps with energy-efficient lamps. A special program allows LCRA's customers to choose any program offered by LCRA to fit their unique needs and be paid an economic incentive for every KW saved.

LCRA has both summer and winter peak reduction goals. The Authority expects its conservation and load management savings on the annual summer peak to equal 108-MW capacity in 1988 and 333 MW by 1997. This is shown on Figure 9.2 as the difference between Peak Demand Before Adjustments and Peak Demand After Adjustments. Adjustments to peak load occurred during the period 1983 to 1986, but precise savings

FIGURE 9.2
LOWER COLORADO RIVER AUTHORITY
NET SYSTEM CAPACITY AND PEAK DEMAND



were not measured. In addition to the summer peak reductions are winter period adjustments growing from 123 MW in 1988 to 178 MW in 1997.

9.2 CAPACITY PLAN

Efficiency Improvements to Supply. Information on LCRA efforts to improve efficiency indicates savings are expected from three programs focused on generation at the Fayette plant and two programs for its transmission system. In addition, a rate program encourages efficiency among the wholesale customers.

Current Installed Capacity. In 1987, LCRA operated 20 generating units with a total capacity of 1,836 MW (see Table 9.3, *Installed Capacity by Fuel Type*). Four gas units make up 56 percent of the installed capacity, partial ownership of two coal units provide 31 percent, and 13 hydroelectric units total 13 percent. Hydroelectric generation is a very efficient means of producing electricity, but there are competing uses for the available water and generation is largely dependent upon rainfall.

Net Generation. Figure 9.3, *Net Generation by Fuel Type*, clearly shows the baseload characteristic of coal generation for LCRA, with 46.9 percent of its power generated by coal in 1987, 42.6 percent by gas; 9.8 percent, hydroelectric power; and 0.7 percent, lignite. LCRA was totally reliant on hydroelectric and gas generation in 1977. Projections show 1997 net generation by coal at 69.4 percent, gas at 27.1 percent, and hydroelectric at 3.5 percent. Over the past seven years installed capacity has not varied but net generation has ranged from 4,961,936 MWH in 1983 to 7,193,556 MWH in 1987. According to LCRA's projections, total system net generation is expected to exhibit an annual growth rate of 4.9 percent, down from the previous 10-year average 6.6 percent rate of increase, to reach 11,630,790 MWH in 1997.

Net System Capacity. Net system capacity is projected to remain at 2,252 MW over most of the forecast period. As shown in Table 9.4, *Net System Capacity and Reserve Margins*, the LCRA made firm off-system sales from 1981 to 1985, but has not contracted for such sales recently and does not project any such sales. No firm purchases are projected. LCRA expects to add 816 MW to its system by 1997.

System Expansion. Over the forecast period, net generating capabilities will grow by over 44 percent, if planned capacity expansion of 816 MW occurs. Already, Fayette 3 has begun commercial operation (on April 29, 1988) at a net capacity of 405 MW.

TABLE 9.3
Installed Capacity by Fuel Type
Lower Colorado River Authority
(MW)

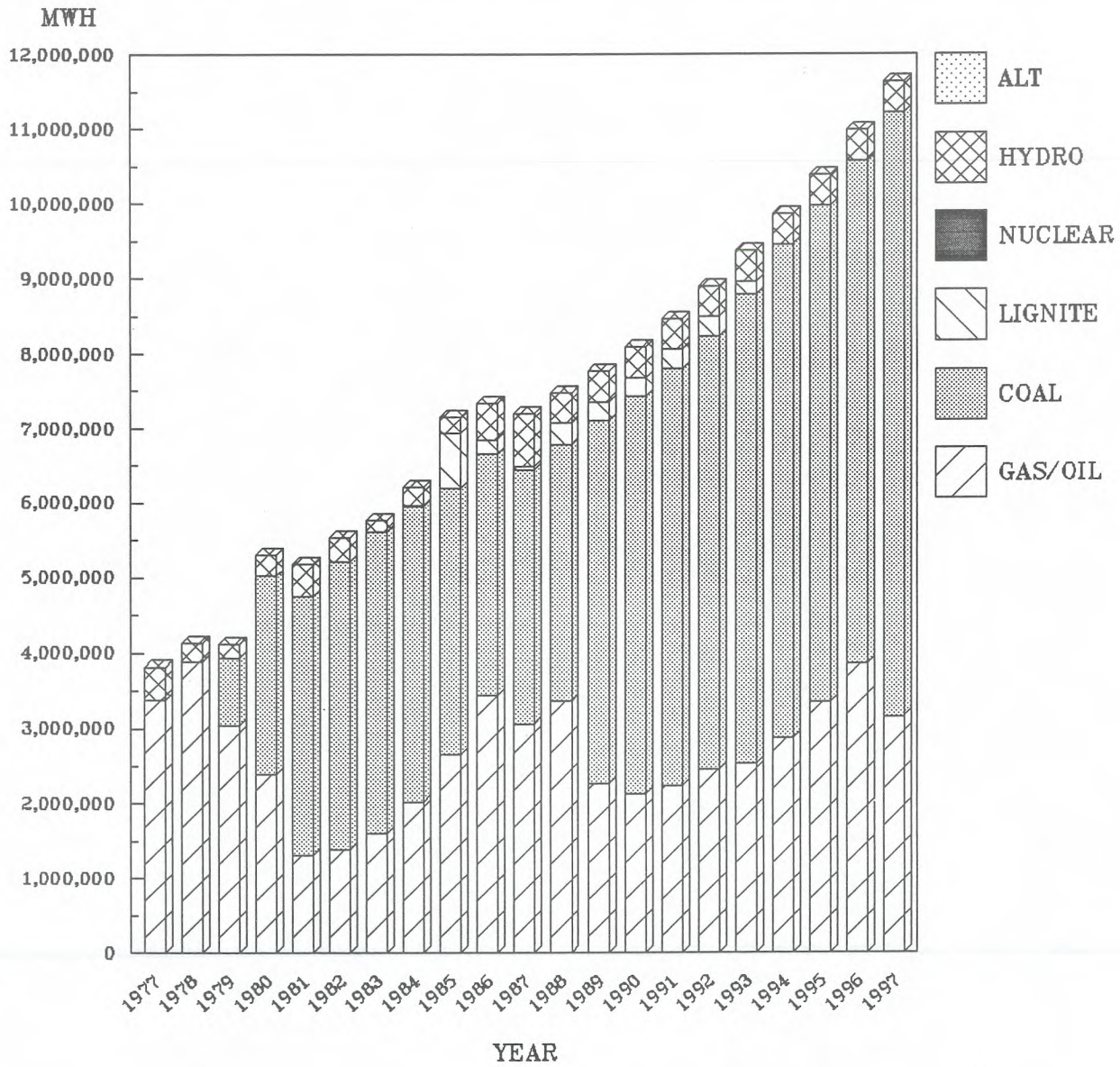
Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	1,050	0	0	0	230	0	1,280
1978	1,050	0	0	0	230	0	1,280
1979	1,050	275	0	0	230	0	1,555
1980	1,050	550	0	0	230	0	1,830
1981	1,050	550	0	0	230	0	1,830
1982	1,050	550	0	0	230	0	1,830
1983	1,050	550	0	0	230	0	1,830
1984	1,025	570	0	0	223	0	1,818
1985	1,025	570	0	0	241	0	1,836
1986	1,025	570	0	0	241	0	1,836
1987	1,025	570	0	0	241	0	1,836
1988	1,025	897	0	0	241	0	2,163
1989	1,025	986	0	0	241	0	2,252
1990	1,025	986	0	0	241	0	2,252
1991	1,025	986	0	0	241	0	2,252
1992	1,025	986	0	0	241	0	2,252
1993	1,025	986	0	0	241	0	2,252
1994	1,025	986	0	0	241	0	2,252
1995	1,025	986	0	0	241	0	2,252
1996	1,025	986	0	0	241	0	2,252
1997	1,025	1,386	0	0	241	0	2,652

Note: Alternate sources do not include cogeneration.

TABLE 9.4
Net System Capacity and Reserve Margins
Lower Colorado River Authority
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	869	869	1,280	0	0	1,280	47.4
1978	888	888	1,280	0	0	1,280	44.1
1979	868	868	1,555	0	0	1,555	79.3
1980	1,067	1,067	1,830	0	0	1,830	71.6
1981	1,078	1,078	1,830	0	25	1,805	67.5
1982	1,158	1,158	1,830	0	70	1,760	51.9
1983	1,221	1,221	1,830	0	100	1,730	41.7
1984	1,314	1,314	1,818	0	210	1,608	22.3
1985	1,434	1,434	1,836	0	230	1,606	12.0
1986	1,515	1,515	1,836	0	0	1,836	21.2
1987	1,514	1,514	1,836	350	0	2,186	44.4
1988	1,532	1,424	2,163	0	0	2,163	51.9
1989	1,592	1,468	2,252	0	0	2,252	53.4
1990	1,656	1,511	2,252	0	0	2,252	49.0
1991	1,733	1,563	2,252	0	0	2,252	44.1
1992	1,816	1,619	2,252	0	0	2,252	39.1
1993	1,914	1,691	2,252	0	0	2,252	33.2
1994	2,013	1,764	2,252	0	0	2,252	27.7
1995	2,116	1,839	2,252	0	0	2,252	22.5
1996	2,230	1,925	2,252	0	0	2,252	17.0
1997	2,360	2,027	2,652	0	0	2,652	30.8

FIGURE 9.3
LOWER COLORADO RIVER AUTHORITY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

Originally planned as a lignite unit, current expectations call for burning both lignite and subbituminous coal. Studies are being conducted to determine if additional capacity is available from this unit, reported on Tables 9.3 and 9.4 as reaching 416 MW in 1989. Another planned coal unit is expected to provide an additional 400 MW in 1997.

Five transmission line construction projects are planned. The Colorado County project calls for 16 miles of 69 KV line to be completed in 1989. Four additional projects involving 68.6 miles of 138 KV line will be added in 1990, 1992, 1994 and 1995 if all goes as planned. Total estimated cost of the transmission projects amounts to $10,566,829.

CHAPTER TEN

CITY OF AUSTIN ELECTRIC UTILITY

The City of Austin Electric Utility, a municipally-owned utility, renders electrical service in Travis County and in a small portion of Williamson County. Most of its 420 square mile certified service area is served solely by the City of Austin Electric Utility Department. About 10 square miles in the northeast corner of the area is dually certified, and customers there can elect to receive electricity from either the COA or TU Electric. The pattern to date shows that residential customers choose COA service and commercial customers choose TU Electric.

COA reported a 1987 peak demand after adjustments of 1,391 MW, down slightly from the previous year. Total sales rose 3 percent however, to 5,761,024 MWH. Installed capacity totals approximately 1,920 MW. Net generation in 1987 exhibited a fuel mix of 68.6 percent coal and 31.4 percent gas. The solar photovoltaic facility provided 0.0075 percent of the electrical energy needed in 1987.

10.1 DEMAND FORECAST

Forecasting Methodology. The COA forecast employs end-use/econometric energy models to project long-term electric sales to customers. The modeling considers a forecast range in its planning process in recognition of the uncertainties in a load forecast. The forecast ranges of system peak and energy consumption are based on historical information and recent per customer or per building patterns of energy use. The ranges include assumptions about the change in number of customers, weather conditions, and appliance efficiencies. The system energy projections provide the inputs to the Hourly Electric Load Model (HELM). In HELM, hourly load shapes for appliances and building types are used to distribute the annual energy forecasts to demand over time. The projections of maximum system demand are modeled to occur between 4 pm and 5 pm on a weekday in August of each year.

Number of Customers. As shown in Table 10.1, Number of Customers by Sector, in 1987, COA provided electric service to 227,910 residential customers. The historical data for the period from 1977 through 1987 reflect an average annual growth rate of 6.3 percent for this class of customers. COA expects a 5.5 percent average annual growth

rate over the forecast period, resulting in an estimated 390,391 residential customers in 1997.

The Utility served 26,991 commercial customers in 1987, up from 14,513 in 1977. The number of industrial customers declined by one since 1986, to seven. The "All Other" retail sales category covers 164 customers in 1987.

Total Sales. Figure 10.1, *Annual Sales by Sector*, shows that in 1987 the residential sector purchased 2,288,239 MWH after 10 years of growth at an average of 7.7 percent per year. A growth rate of 5.2 percent will result in projected sales of 3,785,100 MWH in 1997 to residential customers. Sales of 2,859,767 MWH in 1987 to the commercial sector make that group the largest consumer class in the COA service area. Projected growth in commercial sales occurs at the annual rate of 5.5 percent through 1997, enough to keep the commercial sector at about 50 percent of total sales over the forecast period. Industrial sales are projected to increase to 824,528 MWH from 461,410 MWH in 1987, reflecting a growth rate of 5.9 percent, the largest rate of growth for the three sectors. COA also sold 52,280 MWH off the system in 1987, but makes no projection of off-system sales.

According to COA's projection of total sales, growth will slow from the 7.2 percent average annual rate demonstrated over the past decade to 5.4 percent per year from 1987 through 1997. Sales are expected to total 9,721,368 MWH in 1997.

Peak Demand. Over the period from 1977 through 1987, COA experienced 6.2 percent annual growth in peak demand before adjustments, although Figure 10.2, *Net System Capacity and Peak Demand*, shows peak demand actually fell 17 MW from 1986 to 1987. The utility expects a rebound in 1988, with growth through 1997 projected to occur at about 5.8 percent annually. COA anticipates a peak demand before adjustments of 2,462 MW in 1997.

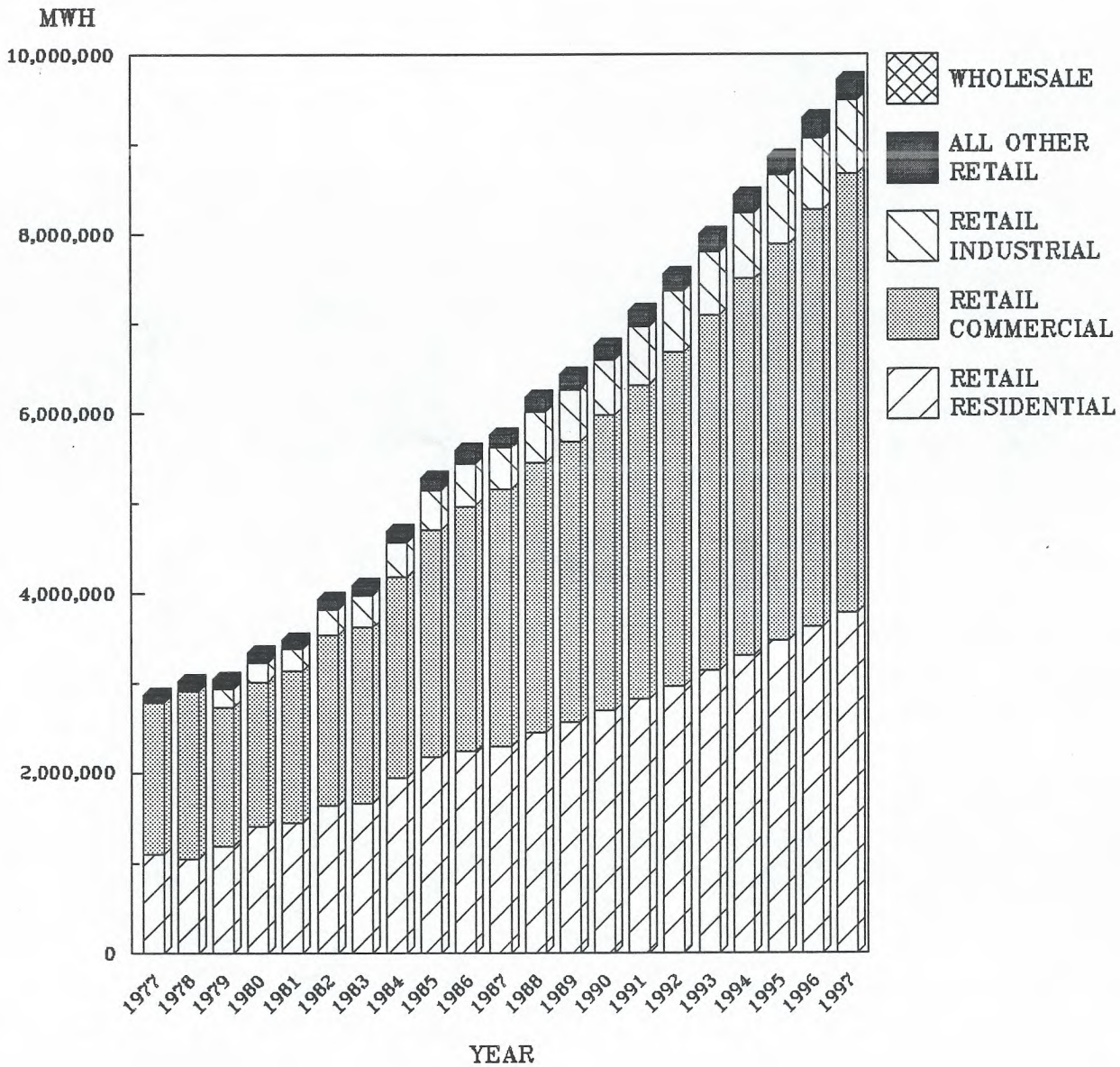
The coincident peak by sector data is not available for 1987, but in 1986 the residential sector accounted for nearly 50 percent of the total with the commercial sector at about 42 percent. No projection of coincident peak load by sector is made. The 1987 non-coincident peak load by sector is not available, but in 1986 the residential non-coincident peak of 845 MW represents the greatest load of any one sector. The non-coincident commercial peak in 1986 was 649 MW.

TABLE 10.1
Number of customer by Sector
City of Austin

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	123,467	14,513	N/A	120	0
1978	131,325	16,162	N/A	132	0
1979	138,382	16,178	5	116	0
1980	149,285	19,486	5	123	0
1981	155,709	17,361	5	116	0
1982	164,377	18,218	7	122	0
1983	175,189	20,309	7	127	0
1984	191,637	22,983	7	133	0
1985	211,829	25,248	8	144	0
1986	224,146	26,738	8	149	0
1987	227,910	26,991	7	164	0
1988	251,191	27,587	7	171	0
1989	265,396	28,182	6	178	0
1990	280,022	28,778	6	186	0
1991	294,618	29,374	6	193	0
1992	309,974	29,969	5	200	0
1993	326,124	30,565	5	207	0
1994	343,107	31,161	5	214	0
1995	360,963	31,756	5	222	0
1996	375,389	32,352	4	229	0
1997	390,391	32,948	4	236	0

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 10.1
CITY OF AUSTIN ELECTRIC UTILITY
ANNUAL SALES BY SECTOR (MWH)



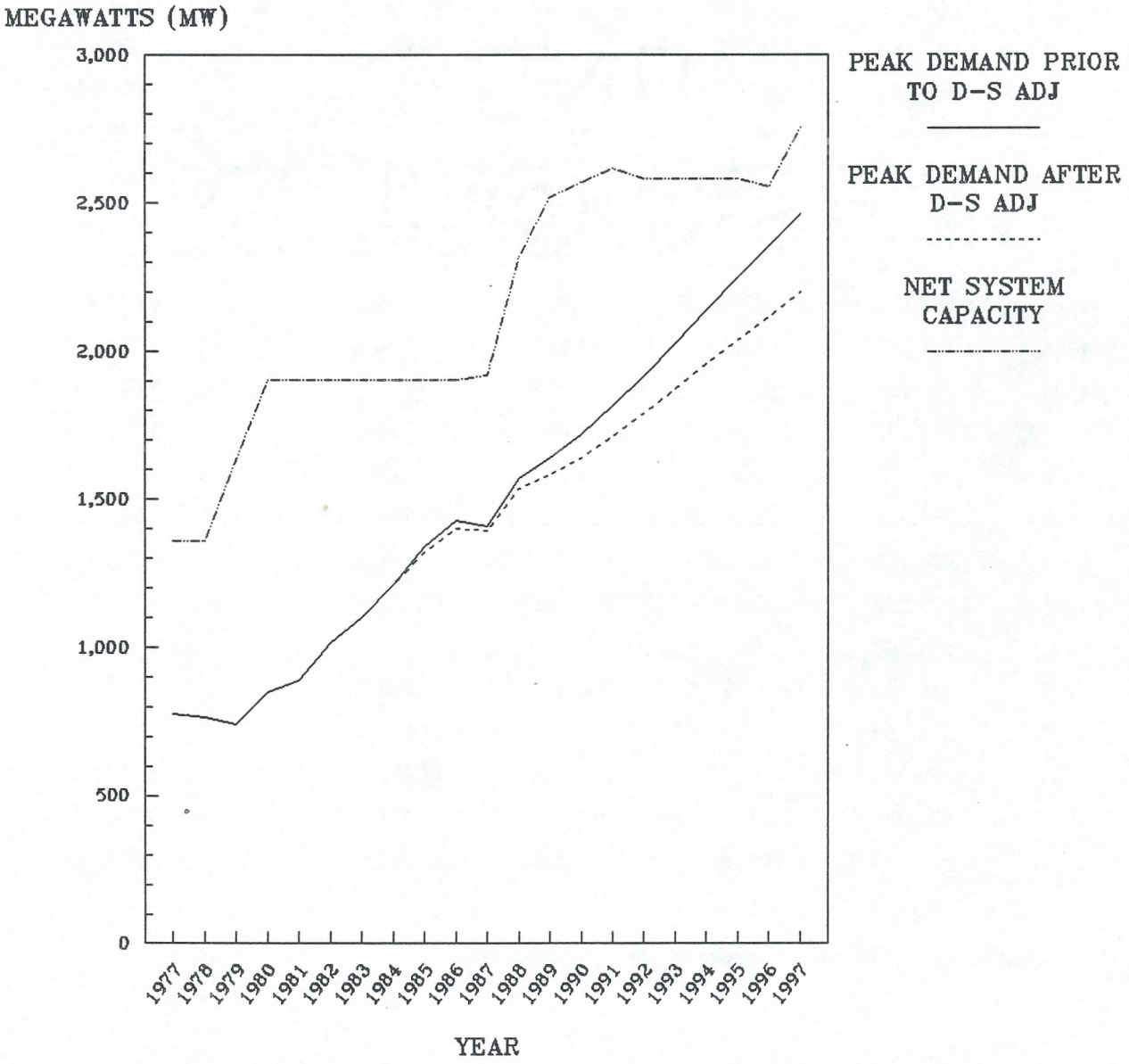
SOURCE: TABLE 10.2

TABLE 10.2
Annual Sales by Sector
City of Austin
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	1,091,516	1,688,751	0	84,475	0	2,864,742
1978	1,047,284	1,861,889	0	111,523	0	3,020,696
1979	1,192,604	1,532,206	210,447	115,923	0	3,051,180
1980	1,408,694	1,608,076	211,716	118,258	0	3,346,744
1981	1,442,954	1,700,231	235,139	110,893	0	3,489,217
1982	1,635,311	1,895,910	289,857	116,502	0	3,937,580
1983	1,658,638	1,961,556	350,202	120,041	0	4,090,437
1984	1,948,662	2,235,518	377,776	135,865	0	4,697,821
1985	2,171,387	2,536,212	432,977	143,519	0	5,284,095
1986	2,235,104	2,732,788	466,956	152,759	0	5,587,607
1987	2,288,239	2,859,767	461,410	151,608	0	5,761,024
1988	2,447,550	3,004,400	559,769	163,167	0	6,174,886
1989	2,559,475	3,118,175	586,422	169,549	0	6,433,621
1990	2,684,350	3,289,300	612,371	176,248	0	6,762,269
1991	2,817,550	3,497,425	646,561	183,990	0	7,145,526
1992	2,963,700	3,716,650	680,187	192,021	0	7,552,558
1993	3,133,900	3,954,375	709,442	199,966	0	7,997,683
1994	3,304,100	4,192,100	737,631	207,661	0	8,441,492
1995	3,475,225	4,412,250	766,522	215,091	0	8,869,088
1996	3,626,925	4,650,900	794,992	222,411	0	9,295,228
1997	3,785,100	4,882,150	824,528	229,590	0	9,721,368

Note: Annual sales figures are prior to demand-side adjustments.

FIGURE 10.2
CITY OF AUSTIN ELECTRIC UTILITY
NET SYSTEM CAPACITY AND PEAK DEMAND



D-S ADJ is Demand-Side Adjustments.

Demand-Side Adjustments. COA states that it successfully implemented a comprehensive demand-side management strategy that includes a mix of peak load reduction and customer information and outreach programs. The energy efficiency goal of implementing all cost-effective resource options and leading to a least-cost resource plan carries with it the objective to displace the need for a conventional electric generation plant by 1995.

COA reported a 17 MW reduction in 1987 peak demand due to conservation and load management practices. This is shown on Figure 10.2 as the difference between Peak Demand Before Adjustments and Peak Demand After Adjustments. The Utility expects its conservation and load management activities to save 36 MW of capacity in 1988 and 262 MW by 1997.

10.2 CAPACITY PLAN

Efficiency Improvements to Supply. Information on COA efficiency improvements in the generation and transmission systems is not available.

Current Installed Capacity. In 1987, COA operated 19 generating units with a total capacity of 1920 MW. (See Table 10.3, *Installed Capacity by Fuel Type*.) Gas plants make up 70 percent of the installed capacity, coal a little under 30 percent, and the photovoltaic plant less than 0.02 percent. Figure 10.3, Net Generation by Fuel Type, clearly shows the baseload characteristic of coal generation for COA, with 68.6 percent of its power generated by coal in 1987. COA was totally reliant on gas generation in 1977; however, gas generators provided only 31.4 percent in 1987. The photovoltaic plant produced 0.0075 percent of the total power generated.

Net System Capacity. As shown on Table 10.4, *Net System Capacity and Reserve Margins*, COA does not provide information on MW capacity of off-system sales and does not project any such sales. Firm purchases of 49 MW will begin in 1990, then double to 98 MW in 1991, and continue at that level through the forecast period. The purchases from Valley View Energy Corp will be generated from two manure-fueled units located in the Texas Panhandle.

System Expansion. Over the forecast period, net generating capabilities will grow by over 39 percent, if planned capacity expansion of 754 MW occurs. COA participation in the South Texas Project adds 200 MW capacity in 1988 and 200 more in 1989, when

TABLE 10.3
Installed Capacity by Fuel Type
City of Austin
(MW)

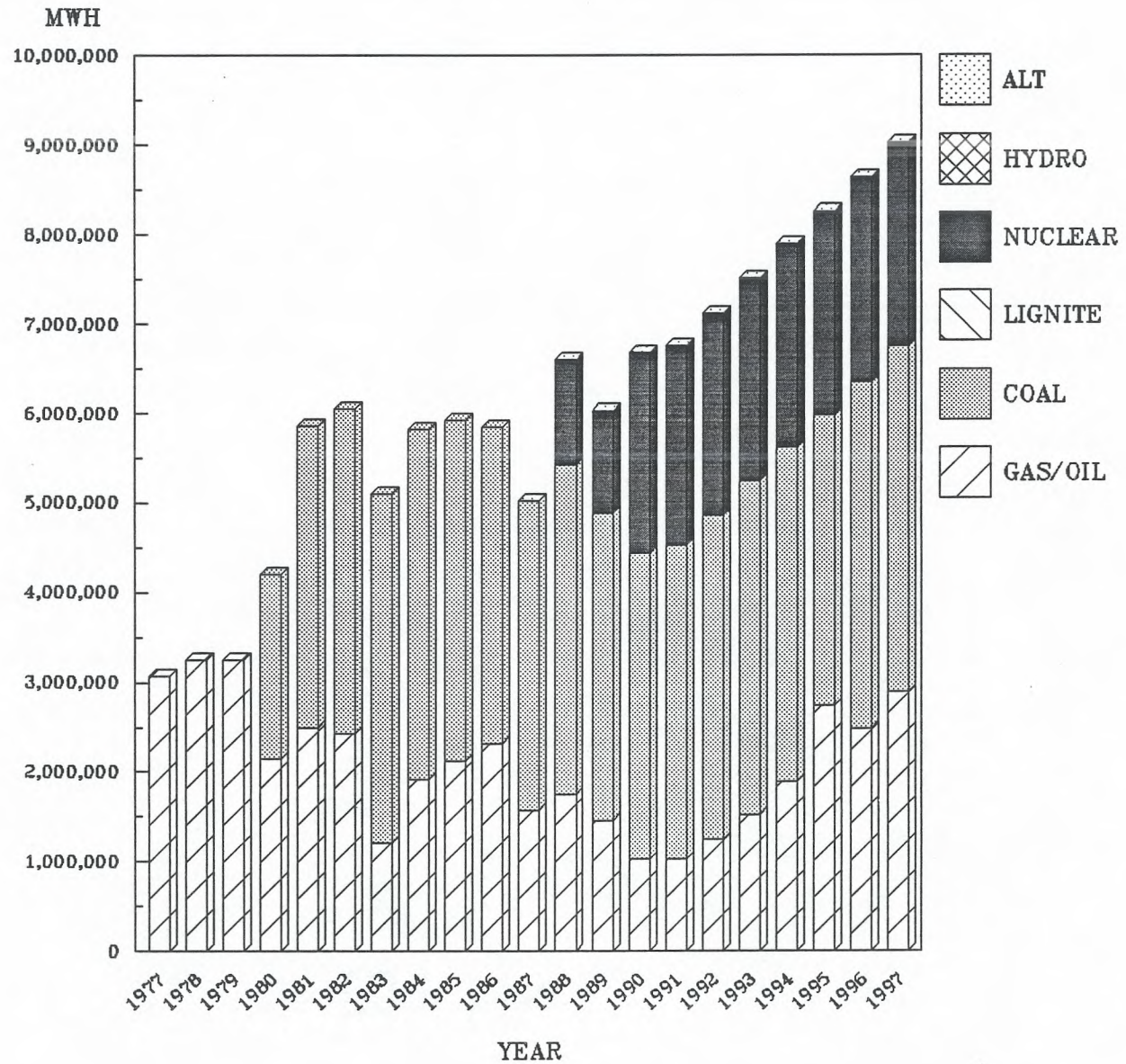
Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	1,356	0	0	0	0	0	1,356
1978	1,356	0	0	0	0	0	1,356
1979	1,356	275	0	0	0	0	1,631
1980	1,356	550	0	0	0	0	1,906
1981	1,356	550	0	0	0	0	1,906
1982	1,356	550	0	0	0	0	1,906
1983	1,356	550	0	0	0	0	1,906
1984	1,356	550	0	0	0	0	1,906
1985	1,356	550	0	0	0	0	1,906
1986	1,356	550	0	0	0	0	1,906
1987	1,350	570	0	0	0	0	1,920
1988	1,550	570	0	200	0	0	2,320
1989	1,550	570	0	400	0	0	2,520
1990	1,550	570	0	400	0	0	2,520
1991	1,550	570	0	400	0	0	2,520
1992	1,514	570	0	400	0	0	2,484
1993	1,514	570	0	400	0	0	2,484
1994	1,514	570	0	400	0	0	2,484
1995	1,514	570	0	400	0	0	2,484
1996	1,486	570	0	400	0	0	2,456
1997	1,686	570	0	400	0	0	2,656

Note: Alternate sources do not include cogeneration.

TABLE 10.4
Net System Capacity and Reserve Margins
City of Austin
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	774	774	1,356	0	0	1,356	75.2
1978	763	763	1,356	0	0	1,356	77.7
1979	743	743	1,631	0	0	1,631	119.5
1980	849	849	1,906	0	0	1,906	124.5
1981	888	888	1,906	0	0	1,906	114.6
1982	1,013	1,013	1,906	0	0	1,906	88.2
1983	1,101	1,101	1,906	0	0	1,906	73.1
1984	1,210	1,210	1,906	0	0	1,906	57.5
1985	1,339	1,320	1,906	0	0	1,906	44.4
1986	1,425	1,402	1,906	0	0	1,906	35.9
1987	1,408	1,391	1,920	0	0	1,920	38.1
1988	1,571	1,535	2,320	0	0	2,320	51.2
1989	1,637	1,581	2,520	0	0	2,520	59.4
1990	1,720	1,640	2,520	49	0	2,569	56.7
1991	1,815	1,711	2,520	98	0	2,618	53.0
1992	1,916	1,788	2,484	98	0	2,582	44.4
1993	2,028	1,873	2,484	98	0	2,582	37.9
1994	2,140	1,959	2,484	98	0	2,582	31.8
1995	2,249	2,040	2,484	98	0	2,582	26.6
1996	2,355	2,117	2,456	98	0	2,554	20.7
1997	2,462	2,200	2,656	98	0	2,754	25.2

FIGURE 10.3
CITY OF AUSTIN ELECTRIC UTILITY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

nuclear generation will provide 15.9 percent of net generation capacity. In view of the fact that Austin is attempting to withdraw from participation in the project, this nuclear capacity is rather uncertain. The forecast projects no lignite capacity but that may be added to replace the nuclear capacity, depending upon the outcome of current litigation and settlement discussions. Projections of coal generation remain a constant 570 MW through the ten-year period ending in 1997.

Four gas-fired generating units totaling 69 MW will be retired over the forecast period. Some 200 MW of additional gas-fueled capacity, the Decker Gas turbines, began operating in June 1988, and a 200-MW combined-cycle turbine station is planned for 1997. Thus net capacity from gas will increase in 1988; then drop before rising to 1686 MW in 1997, a level about 25 percent greater than that of 1987. An 18-MW refuse fueled plant is projected to come on line in 1990, but recent City actions indicate this will be delayed if not cancelled.

Two transmission line projects are included in COA's construction work in progress. One began in 1987 and one in 1988. These two lines total 8.7 miles of 138 KV line and carry an estimated cost of $7,735,000. The lines are located in Travis and Williamson Counties.

CHAPTER ELEVEN

WEST TEXAS UTILITIES COMPANY

West Texas Utilities Company is a public utility engaged in generating, purchasing, transmitting, and distributing electricity. The utility's service area covers an estimated 53,000 square miles in north central and west Texas. The two largest cities served by the utility are Abilene and San Angelo. WTU is a subsidiary of the Central and South West Corporation and a member of ERCOT.

WTU is an investor-owned company. Its revenues for 1987 totaled $256,756,000, while total assets as of December 31, 1987 were $735,327,000. The Company's capital structure was comprised of 49.1 percent common equity, 8.3 percent preferred stock, and 42.6 percent long-term debt.

WTU is a summer peaking utility. The annual peak demand usually occurs during the months of either July or August. Peak demand after adjustments was 1,077 MW in 1987. The utility projected its 1987 aggregate sales to be 5,405,021 MWH. WTU possesses the installed capacity to generate up to 1,443 MW. In 1987 about 70 percent of the total electricity generated by the utility used gas as the primary fuel. The remaining electricity was generated utilizing either coal or oil as the source of energy.

11.1 DEMAND FORECAST

Forecasting Methodology. In formulating its forecasts of peak loads, WTU uses an exponential time-trend extrapolation method to project historical trends into the future. The exponential relations are derived through a series of processes which involve the manipulation of such data as hourly system temperatures and hourly system loads. WTU employs a modular forecasting system to project its sales. The system is composed of two components: 1) a regional economic and demographic component and, 2) a company KWH sales component. Both components are subsystems which describe or emulate items which measure levels of economic activity. Equations are derived using basic economic behavioral theory and facts about the items under consideration. The resulting equations are combined into one automated simulation routine. Once the routine is developed, the utility performs a four-step process to generate a KWH sales forecast.

Number of Customers. As shown in Table 11.1, *Number of Customers by Sector*, WTU provided electric service to 141,200 residential customers in 1987. The historical data for the period from 1977 through 1987 reflect an average annual growth rate of 2.2 percent for this class of customers. The Company expects a 2.1 percent annual growth rate into 1997. WTU served 24,500 commercial customers in 1987. The utility projects a slight decline in the growth rate from 2.7 percent annually for the period from 1977 to 1987 down to 2.1 percent over the next ten years. Unlike either the residential or commercial sector, the industrial sector exhibits a fairly constant average per annum growth. Over the historical period, 1977 through 1987, this class grew at an average rate of approximately 6 percent per year. A 6 percent annual growth rate is also expected for the period from 1987 through 1997. Currently, WTU serves 6,374 industrial customers.

Annual Sales. As shown in Figure 11.1, *Annual Sales by Sector*, in 1977 the second largest contributor to total sales was the residential sector. In this year sales to residential customers comprised 23.6 percent of the aggregate sales. In 1987 the residential sector purchased 1,357,543 MWH of electricity. Currently, this class maintains the position as the second-largest customer class, purchasing 25.1 percent of the total. The utility has projected an average annual rate of growth for sales to the residential sector of 3.2 percent . This is down somewhat from the 4.1 percent annual growth experienced over the previous decade. The utility projects the residential class' contribution to the total sales will be 26.1 percent by 1997.

Historically, the commercial sector exhibited a growth rate of 4.4 percent annually. WTU expects this rate to remain fairly constant into the future. It is predicting 4.4 percent annual growth for the period from 1987 through 1997 as well. This represents the highest per annum growth expected of any sector. Sales to commercial customers totaled 1,017,418 MWH in 1987. This amount represents 18.8 percent of the total sales which makes this sector the fourth-largest customer class.

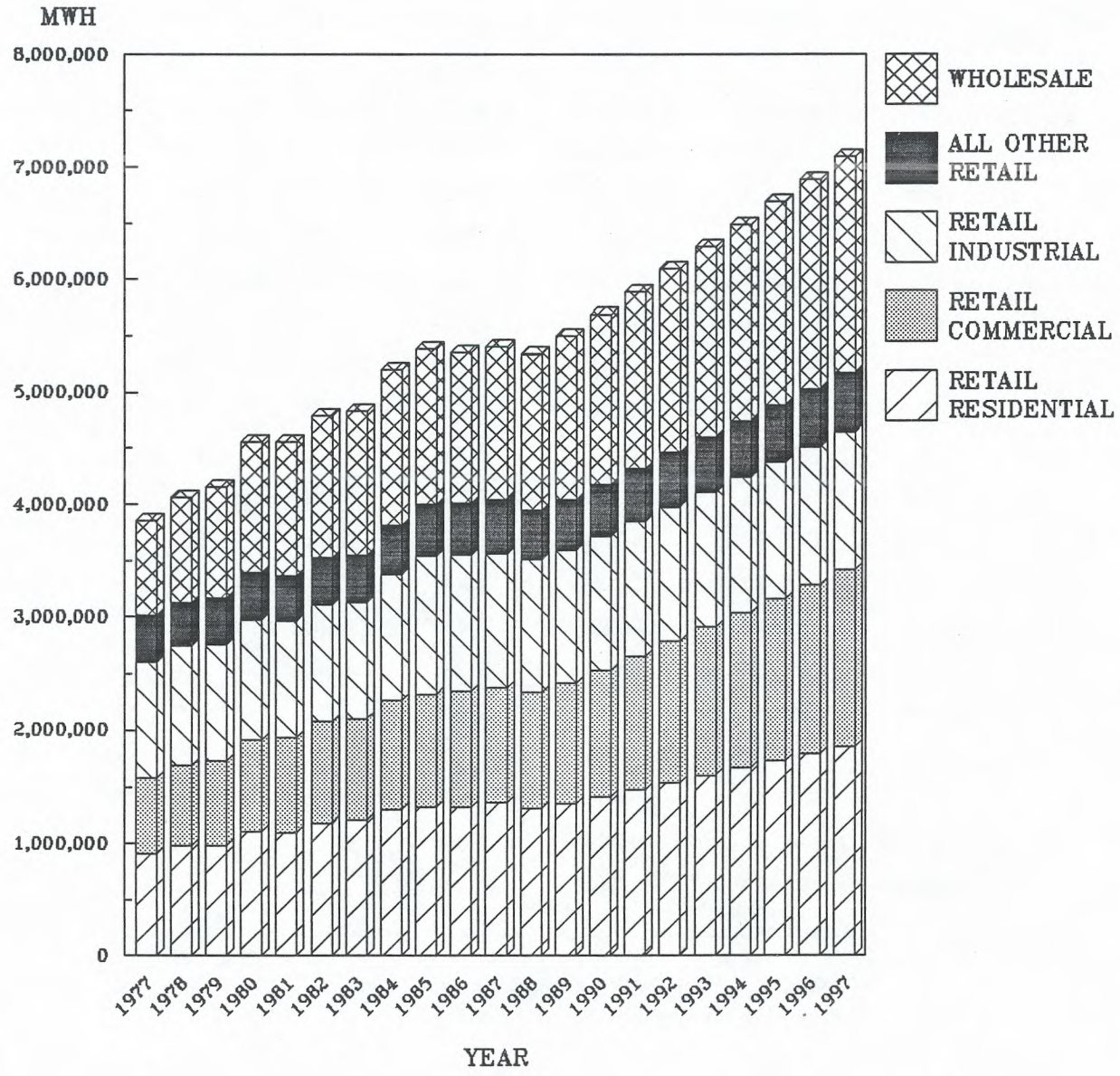
The industrial class purchased 21.9 percent of the total electricity generated by the Company in 1987. The total industrial sales in that year amounted to 1,180,930 MWH. The industrial sector has moved from the largest purchaser in 1977 to the third largest in 1987. The utility projects an even slower 0.42 percent annual rate of growth through 1997. WTU anticipates that the industrial sector will drop in position to the fourth-largest consumer by 1997.

TABLE 11.1
Number of customer by Sector
West Texas Utilities Company

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	113,332	18,860	3,577	4,284	129
1978	117,710	19,807	3,674	4,491	132
1979	120,762	20,455	4,021	4,636	133
1980	124,275	21,509	4,405	4,780	129
1981	127,020	21,515	4,731	4,564	126
1982	131,164	22,541	4,799	4,571	126
1983	135,841	22,953	5,380	4,724	128
1984	141,405	23,144	6,135	4,877	121
1985	142,993	24,112	6,399	5,026	120
1986	141,750	24,126	6,410	5,179	124
1987	141,200	24,500	6,374	5,452	121
1988	140,610	24,340	7,580	4,180	120
1989	143,990	24,950	7,950	4,250	120
1990	147,780	25,620	7,370	4,340	120
1991	151,640	26,290	8,810	4,450	120
1992	155,460	26,950	9,240	4,560	120
1993	159,160	27,590	9,670	4,670	120
1994	162,790	28,210	10,100	4,780	120
1995	166,410	28,840	10,540	4,890	120
1996	170,080	29,470	11,000	5,000	120
1997	173,830	30,110	11,440	5,110	120

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 11.1
WEST TEXAS UTILITIES COMPANY
ANNUAL SALES BY SECTOR (MWH)



SOURCE: TABLE 11.2

TABLE 11.2
Annual Sales by Sector
West Texas Utilities Company
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	907,778	664,808	1,035,219	408,205	835,543	3,851,553
1978	978,809	707,532	1,063,797	378,820	933,363	4,062,321
1979	985,026	746,493	1,023,736	417,805	980,373	4,153,433
1980	1,103,256	814,301	1,057,543	422,968	1,151,784	4,549,852
1981	1,093,200	847,941	1,017,668	405,799	1,186,576	4,551,184
1982	1,181,500	895,033	1,030,711	421,663	1,260,822	4,789,729
1983	1,202,486	902,503	1,017,121	424,981	1,287,762	4,834,853
1984	1,300,552	960,213	1,115,485	440,269	1,383,167	5,199,686
1985	1,322,966	998,130	1,213,724	466,334	1,387,680	5,388,834
1986	1,317,942	1,033,157	1,197,275	462,484	1,343,154	5,354,012
1987	1,357,543	1,017,418	1,180,930	487,614	1,361,516	5,405,021
1988	1,311,725	1,027,284	1,164,072	449,374	1,387,400	5,339,855
1989	1,351,108	1,067,775	1,170,387	454,896	1,451,100	5,495,266
1990	1,411,179	1,122,784	1,176,402	463,996	1,514,100	5,688,461
1991	1,475,043	1,184,191	1,183,217	473,996	1,575,800	5,892,247
1992	1,539,013	1,245,019	1,190,332	483,996	1,634,800	6,093,160
1993	1,602,540	1,306,021	1,197,847	493,796	1,691,600	6,291,804
1994	1,664,664	1,367,714	1,205,662	503,396	1,747,400	6,488,836
1995	1,726,311	1,429,762	1,213,877	512,896	1,803,500	6,686,346
1996	1,788,505	1,493,413	1,222,592	522,496	1,860,400	6,887,406
1997	1,851,451	1,558,764	1,231,507	532,196	1,917,300	7,091,218

Note: Annual sales figures are prior to demand-side adjustments.

The remaining retail sales are composed primarily of sales to cotton gins, sales for irrigation, and sales to municipalities for street lighting and other purposes. These combined sales amounted to 487,614 MWH in 1987, or 9 percent of the total sales for that year. The growth rate for this combination of classes is expected to decrease from the 1.8 percent per year over the historical period to 0.9 percent per year over the period from 1987 through 1997.

In 1977 the wholesale sector accounted for a notable 21.7 percent of the total sales. By 1987, sales to this sector had grown at an average rate of 5 percent per year to 1,361,516 MWH or 25.2 percent of the total. Over the historical period the wholesale sector exhibited the highest growth rate of any sector and consequently has grown from the third-largest purchasing sector to the largest. The utility does not anticipate the growth in this sector to be quite as strong as has been demonstrated in the past. WTU projects an annual growth rate of only 3.5 percent through 1997. However, this decline in average growth per year is not sufficient to alter its standing as the major purchasing sector. In fact, the utility anticipates a small increase in the wholesale class' contribution to the total sales, up to 27 percent by 1997.

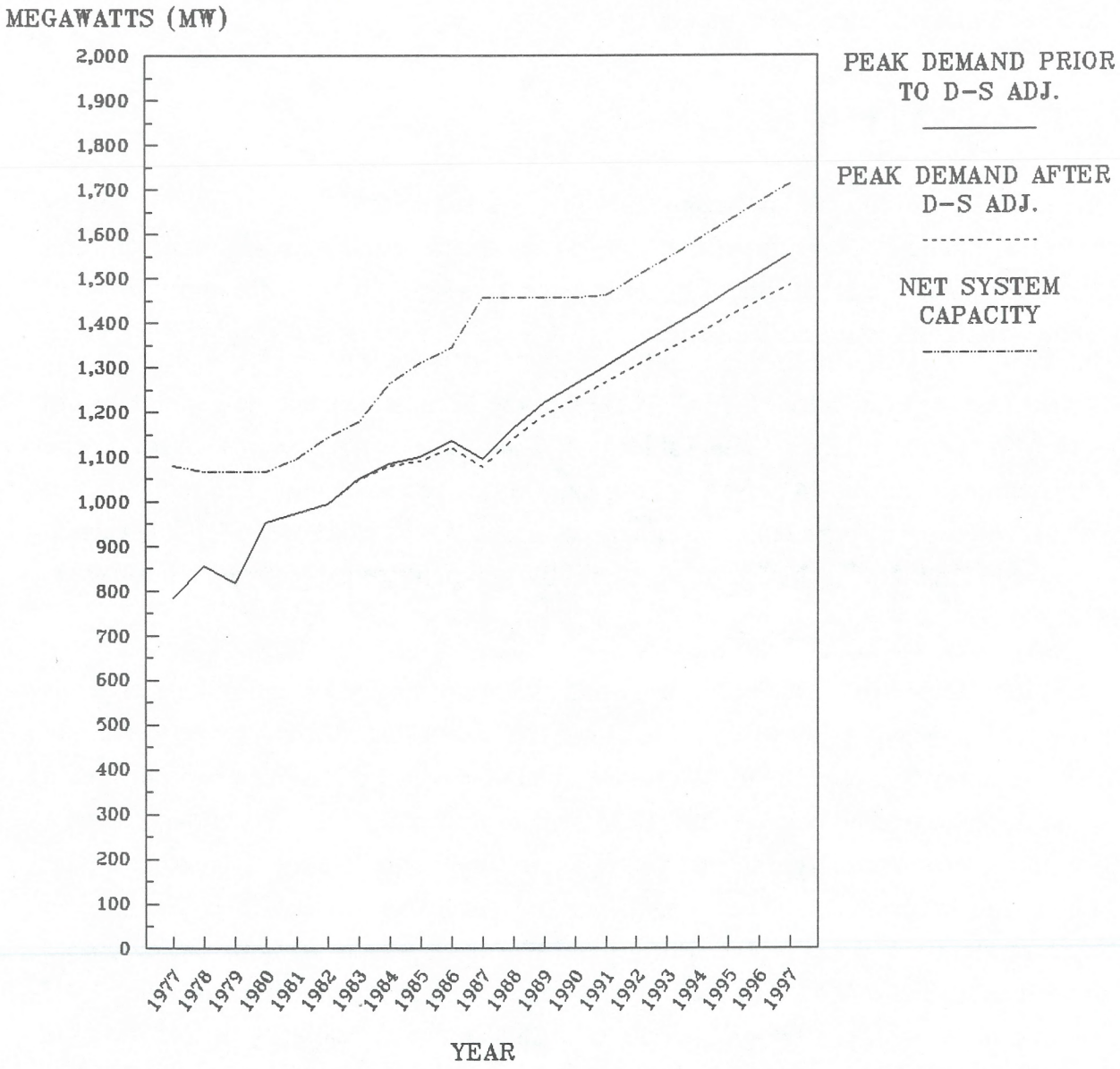
Peak Demand. Over the period from 1977 through 1987 WTU experienced 3.2 percent annual growth in peak demand for its system. Figure 11.2, *Net System Capacity and Peak Demand*, shows that peak demand rose from 785 MW in the base year to 1,077 MW in 1987. The utility expects growth from 1987 to 1997 to occur at about 3.3 percent annually. WTU anticipates a peak demand after adjustments of 1,486 MW for its system by 1997.

Of the 1987 system peak before adjustments of 1,095 MW, the coincident peak of the residential sector accounted for 34.2 percent of the total system peak demand; the commercial sector, 28.6 percent; the wholesale sector, 20.5 percent; and the industrial sector, 13 percent.

In 1987 the sector with the highest non-coincident peak was the residential sector which peaked at 406 MW. The residential sector was followed by the commercial sector with 364 MW. The wholesale sector reached a peak of 245 MW and the industrial sector peaked at 148 MW in 1987.

Demand-Side Adjustments. WTU has stated that its primary goals are to reduce peak demand and increase the use of off-peak energy. The majority of the Utility's 16 end-user programs are aimed at residential and commercial customers. These programs

FIGURE 11.2
WEST TEXAS UTILITIES COMPANY
NET SYSTEM CAPACITY AND PEAK DEMAND



D-S ADJ. is Demand-Side Adjustments.

offer economic incentives to customers who install efficient heating and cooling equipment. By offering incentives to its commercial customers, the utility encourages the installation of heat recovery systems for air conditioning units, heat pumps, and electric water heaters with solar assistance.

In 1987, WTU reported a 18.6 MW reduction in peak demand due to its conservation and load management activities. By 1997, the utility projects a total reduction of 68.3 MW as a result of its energy efficiency programs. The effects of the utility's adjustments may be seen in Figure 11.2 as the difference between Peak Demand Before Adjustments and Peak Demand After Adjustments.

11.2 CAPACITY PLAN

Efficiency Improvements to Supply. WTU has submitted three supply efficiency programs. These programs focus on power plant efficiency, transmission and distribution, and the replacement of incandescent street lights with the more efficient mercury or high-pressure sodium units.

Current Installed Capacity. In 1987 WTU had the installed capacity to generate up to 1,443 MW of electricity. (See Table 11.3, *Installed Capacity by Fuel Type.*) The overwhelming majority, 74 percent, of this capacity is fired using gas. The remainder of the installed capacity is fueled using either coal or oil. At the close of 1987, WTU carried a production plant balance of approximately $0.4 billion historical cost with a book value of $0.3 billion.

Net System Capacity. Installed capacity plus the net of firm sales and purchases yields net system capacity. As shown in Table 11.4, *Net System Capacity and Reserve Margins*, in 1977, the net system capacity for WTU was 1,080 MW with 1,068 MW being contributed by the utility's installed capacity and 12 MW from firm purchases. WTU maintained a 37.6 percent reserve margin in that year. The reserve margin is represented in Figure 11.2 as the difference between Peak Demand After Adjustments and Net System Capacity. In 1987, WTU reported firm purchases of only 13 MW; however, purchases reached as high as 274 MW in the previous year. A current installed capacity of 1,443 MW combined with the 13 MW purchased resulted in a net capacity of 1,456 MW in 1987. The utility's reserve margin for 1987 was calculated to be 35.2 percent. WTU is projecting a slight increase in its net system capacity over the forecast period. The Company expects no change in installed capacity and will meet its rising demand through

TABLE 11.3
Installed Capacity by Fuel Type
West Texas Utilities Company
(MW)

Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	1,068	0	0	0	0	0	1,068
1978	1,054	0	0	0	0	0	1,054
1979	1,054	0	0	0	0	0	1,054
1980	1,054	0	0	0	0	0	1,054
1981	1,054	0	0	0	0	0	1,054
1982	1,054	0	0	0	0	0	1,054
1983	1,059	0	0	0	0	0	1,059
1984	1,067	0	0	0	0	0	1,067
1985	1,068	0	0	0	0	0	1,068
1986	1,070	0	0	0	0	0	1,070
1987	1,079	364	0	0	0	0	1,443
1988	1,079	364	0	0	0	0	1,443
1989	1,079	364	0	0	0	0	1,443
1990	1,079	364	0	0	0	0	1,443
1991	1,079	364	0	0	0	0	1,443
1992	1,079	364	0	0	0	0	1,443
1993	1,079	364	0	0	0	0	1,443
1994	1,079	364	0	0	0	0	1,443
1995	1,079	364	0	0	0	0	1,443
1996	1,079	364	0	0	0	0	1,443
1997	1,079	364	0	0	0	0	1,443

Note: Alternate sources do not include cogeneration.

TABLE 11.4
Net System Capacity and Reserve Margins
West Texas Utilities Company
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	785	785	1,068	12	0	1,080	37.6
1978	857	857	1,054	13	0	1,067	24.5
1979	819	819	1,054	12	0	1,066	30.2
1980	954	954	1,054	13	0	1,067	11.9
1981	974	974	1,054	42	0	1,096	12.5
1982	994	994	1,054	88	0	1,142	15.0
1983	1,051	1,049	1,059	119	0	1,178	12.3
1984	1,085	1,079	1,067	199	0	1,266	17.3
1985	1,100	1,089	1,068	243	0	1,311	20.3
1986	1,135	1,120	1,070	274	0	1,344	20.0
1987	1,095	1,077	1,443	13	0	1,456	35.1
1988	1,165	1,142	1,443	14	0	1,457	27.6
1989	1,221	1,193	1,443	14	0	1,457	22.1
1990	1,261	1,229	1,443	14	0	1,457	18.6
1991	1,303	1,266	1,443	20	0	1,463	15.6
1992	1,345	1,303	1,443	61	0	1,504	15.4
1993	1,385	1,339	1,443	102	0	1,545	15.4
1994	1,427	1,376	1,443	145	0	1,588	15.4
1995	1,470	1,413	1,443	187	0	1,630	15.4
1996	1,511	1,449	1,443	229	0	1,672	15.4
1997	1,554	1,486	1,443	271	0	1,714	15.3

increased purchases. The utility is projecting firm purchases of 271 MW in 1997, resulting in a net system capacity of 1,714 MW for the system. This net capacity would yield a reserve margin of 15.3 percent for 1997.

Net Generation. As shown in Figure 11.3, *Net Generation by Fuel Type*, in 1977 WTU generated 97.4 percent of its electricity using gas. The remaining electricity was generated using oil. Beginning in 1986, WTU was able to diversify its fuel mix somewhat from the 1977 composition by installing additional coal-fired capacity. By 1987, 70 percent of the total electricity generated by the utility used gas as the source of energy. Coal generation contributed 29.4 percent of the total. Oil-powered generation accounted for the remaining 0.4 percent. By 1997 the Company expects to generate 62.1 percent of its electricity using gas, 37.3 percent using coal, and 0.6 percent using oil. WTU projects its total net generation to be 5,398,686 MWH, excluding purchased power, by 1997.

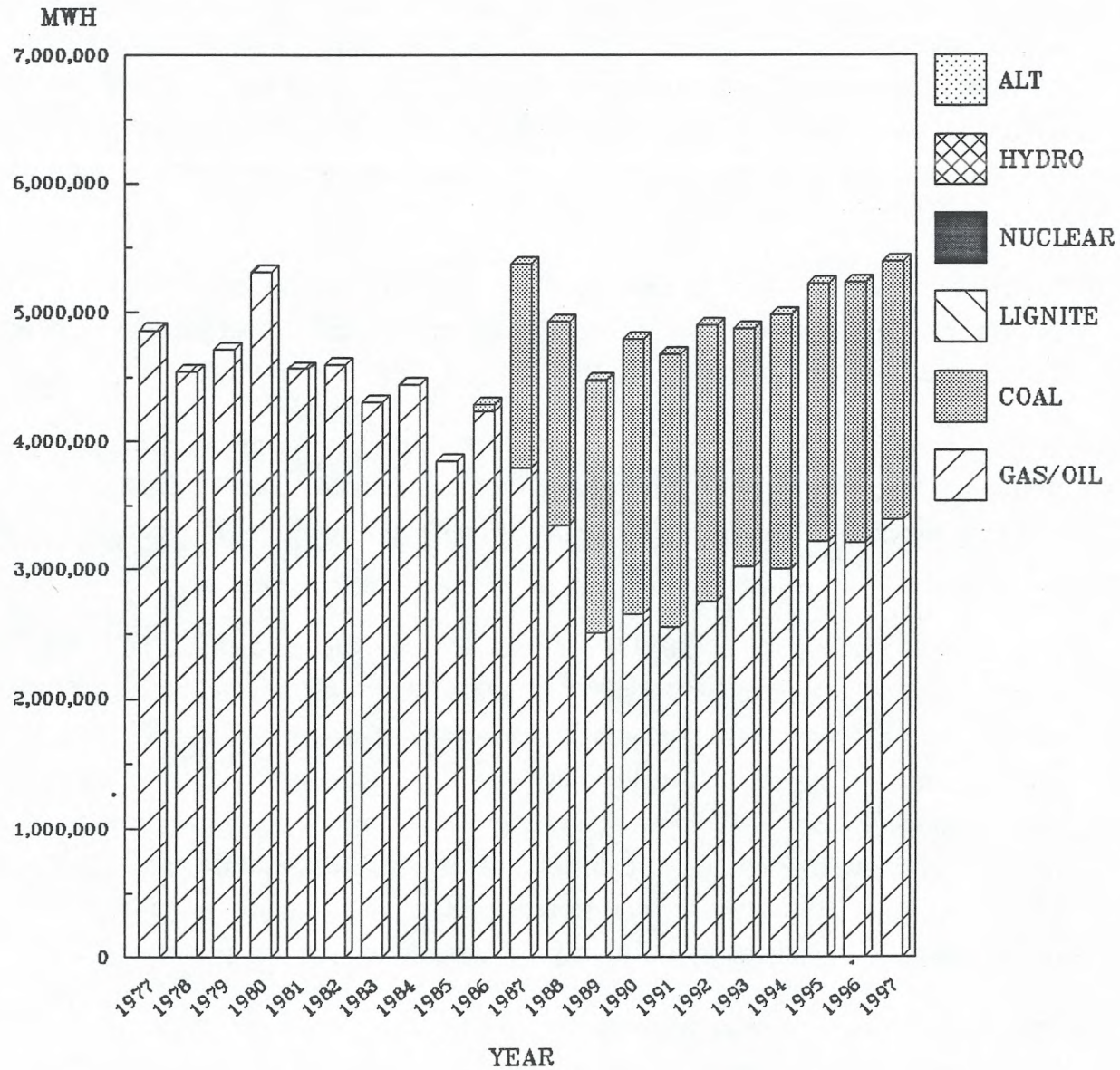
System Expansion. WTU has recently added 364 MW of capacity to its system. This figure represents approximately 54.7 percent of the Oklaunion coal plant in Wilbarger, Texas. This station began commercial operation in December of 1986.

WTU currently has plans to retire five gas plants. All of the plants are scheduled to be retired in December of 1997. The units are Abilene 3 and 4, Lake Pauline 1, Concho 3, and Fort Stockton 2. These retirements will result in a total 65-MW reduction in the WTU system.

Certain WTU power plant sites were initially designed for generating units not now planned to be installed over the next ten years. However, the potential for adding initially planned capability is limited by financial, water, environmental and transmission requirements, site layout, and fuel supply. Specific units, listed in Chapter One of this volume under "Potential Additions at Existing Sites," may also be limited by ambient air quality standards, station water balnce, cooling pond temperature, water discharge permit and solid waste handling and storage. Site specific studies would be needed to determine the best technology and size of any unit additions.

Included in WTU's planned construction work through 1997 are 11 major transmission line projects. Five of these lines are to be completed in the five-year period through 1992. A stretch of approximately 28.6 miles of 69 KV line located in Brewster and Davis Counties is due to begin construction in February 1989 and be completed by June 1989. This project carries an estimated cost of $1,253,000. In January of 1991 WTU plans to

FIGURE 11.3
WEST TEXAS UTILITIES COMPANY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

begin construction of 53.5 miles of 138 kv line located in Pecos, Reeves, Ward, and Ector Counties. The project will last six months with a cost of $3,142,000. In Coke and Runnels Counties five miles of 138 KV line is due to begin construction in January of 1992. The line will be completed in July 1992 and cost $295,000. The Childress-Lake Pauline line consists of 37.5 miles of 138 KV line located in Childress, Cottle, and Hardeman Counties. Construction on the line was to begin in February of 1988 and be completed in July of 1988. Total cost is an estimated $1,882,000. The fifth line to be constructed before the end of 1992 is the Spur-Salt Creek Substation line located in Dickens and Kent Counties. This project will consist of 17.2 miles of 138 KV line. Construction is scheduled to begin in January of 1989 and be completed in May 1989 with an estimated cost of $1,015,000. The six lines scheduled for construction between 1993 and 1997 will result in a total 237.6 additional miles of 138 KV transmission line. These projects are located in several counties in the WTU service area. The combined cost of these six projects is an estimated $16,849,000.

CHAPTER TWELVE

EL PASO ELECTRIC COMPANY

El Paso Electric Company, an investor-owned public utility, generates, transmits and distributes electric energy, serving the county of El Paso and portions of the counties of Culberson and Hudspeth in the State of Texas. The Company serves portions of Dona Ana, Sierra, Otero and Luna Counties in the State of New Mexico. EPE has transmission line interconnections in the states of Arizona and New Mexico and to the Republic of Mexico and provides electrical energy at wholesale to Rio Grande Electric Cooperative, Inc., to Texas-New Mexico Power Company and to Imperial Irrigation District in California. EPE operates as a member of Western Systems Coordinating Council.

EPE revenues for 1987 totaled $450,116,000 while total assests as of December 31, 1987 were $2,275,573,000. The Company's capital structure at that date was comprised of 38.8 percent common equity, 8.8 percent preferred stock, and 52.7 percent long-term debt.

EPE reported a 1987 peak demand of 828 MW. Texas sales, 3,137,757 MWH, amount to 78.4 percent of the total EPE system sales of 4,002,423 MWH.

12.1 DEMAND FORECAST

Forecasting Methodology. EPE applies econometric methods to develop approximately 75 percent of its sales forecast, and judgemental and survey estimates for the remainder. Estimates of the basic native system load, consisting of the service area in Texas and New Mexico, begin with development of the estimates of sales for each customer class and the addition of sales to the wholesale customer, Rio Grande Electric Cooperative (RGEC). Estimates for Company use and unaccounted-for losses are combined with customer class and RGEC total to obtain net-energy-output-to-lines. By applying a projected load-factor to this figure a basic system peak is developed. Extraordinary loads are then added along with off-system losses to obtain the peak demand. EPE continues to develop and improve models for segmented residential sales forecasts and appliance efficiency forecasts.

Number of Customers. As shown in Table 12.1B, *Number of Customers in Texas by Sector*, EPE provided electric service to 160,010 residential customers in 1987. The historical data for the period from 1977 through 1987 reflect an average annual growth rate of 3.5 percent for this class of customers. EPE expects a 2.2 percent annual growth rate over the forecast period through 1996, the last year for which the utility makes projections.

The Company served 15,324 commercial customers in 1987. The historical growth rate for the commercial sector averaged 3.6 percent per annum over the period from 1977 through 1987. EPE anticipates serving 15,870 commercial customers in 1988 but does not project the number of commercial customers beyond that time.

The industrial sector includes 37 customers in the base year, one less than in 1985. The Company expects to serve 39 industrial customers in 1988 but does not project the number of industrial customers.

EPE serves 1,749 other retail customers, primarily municipalities, and two wholesale customers. The Company does not project numbers for other retail customers beyond 1988 when it expects to serve 1,792 other retail customers. Comparable data for the total EPE system is shown in Table 12A.1.

Annual Sales. In terms of energy sales, the commercial sector provides the biggest market for EPE. Sales to commercial customers amounted to 1,073,035 MWH, 34 percent of the total system sales in Texas. Steady growth over the past 10 years averaged 4 percent annually and projections indicate this may even increase a little to 4.2 percent per year through 1997, when the commercial sector will take nearly 38 percent of the system sales.

The stable industrial base in EPE's Texas service areas will provide only a 1.75 percent annual growth in total sales over the forecast period, according to Company expectations. Figure 12.1A and 12.1B, *Annual Sales in Texas by Sector*, show that in 1987 the industrial sector purchased 591,697 MWH, about 19 percent of total system sales in Texas. By 1997, the industrial sector will take only 16.6 percent of total sales, or 703,964 MWH. The historic sales to the industrial show an increase from 1977 through 1980, then decreasing sales for two years before reaching the all-time peak of 718,963 MWH in 1984. Sales have been falling since then and are not expected to achieve that level over the forecast period. Comparable data for the total EPE system is provided in Figure 12.1A and Table 12.2A.

TABLE 12.1A
Number of customer by Sector
El Paso Electric Company — Total System

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	138,898	14,044	39	2,105	2
1978	147,555	14,729	34	2,243	2
1979	154,431	15,197	35	2,341	2
1980	160,364	15,474	35	2,393	2
1981	165,239	15,973	35	2,437	2
1982	169,383	16,535	34	2,488	2
1983	174,258	17,119	34	2,547	2
1984	181,926	17,811	34	2,563	2
1985	188,207	19,389	40	2,242	2
1986	194,831	20,105	39	2,305	2
1987	201,525	20,777	39	2,405	2
1988	208,641	21,620	41	2,458	2
1989	209,661	22,422	42	2,528	2
1990	215,634	23,253	43	2,600	2
1991	221,389	24,116	44	2,675	2
1992	227,368	25,010	45	2,752	2
1993	233,807	25,938	46	2,831	2
1994	240,169	26,899	47	2,913	2
1995	246,388	27,897	48	2,997	2
1996	252,609	28,932	50	3,084	2
1997	260,098	30,005	51	3,174	2

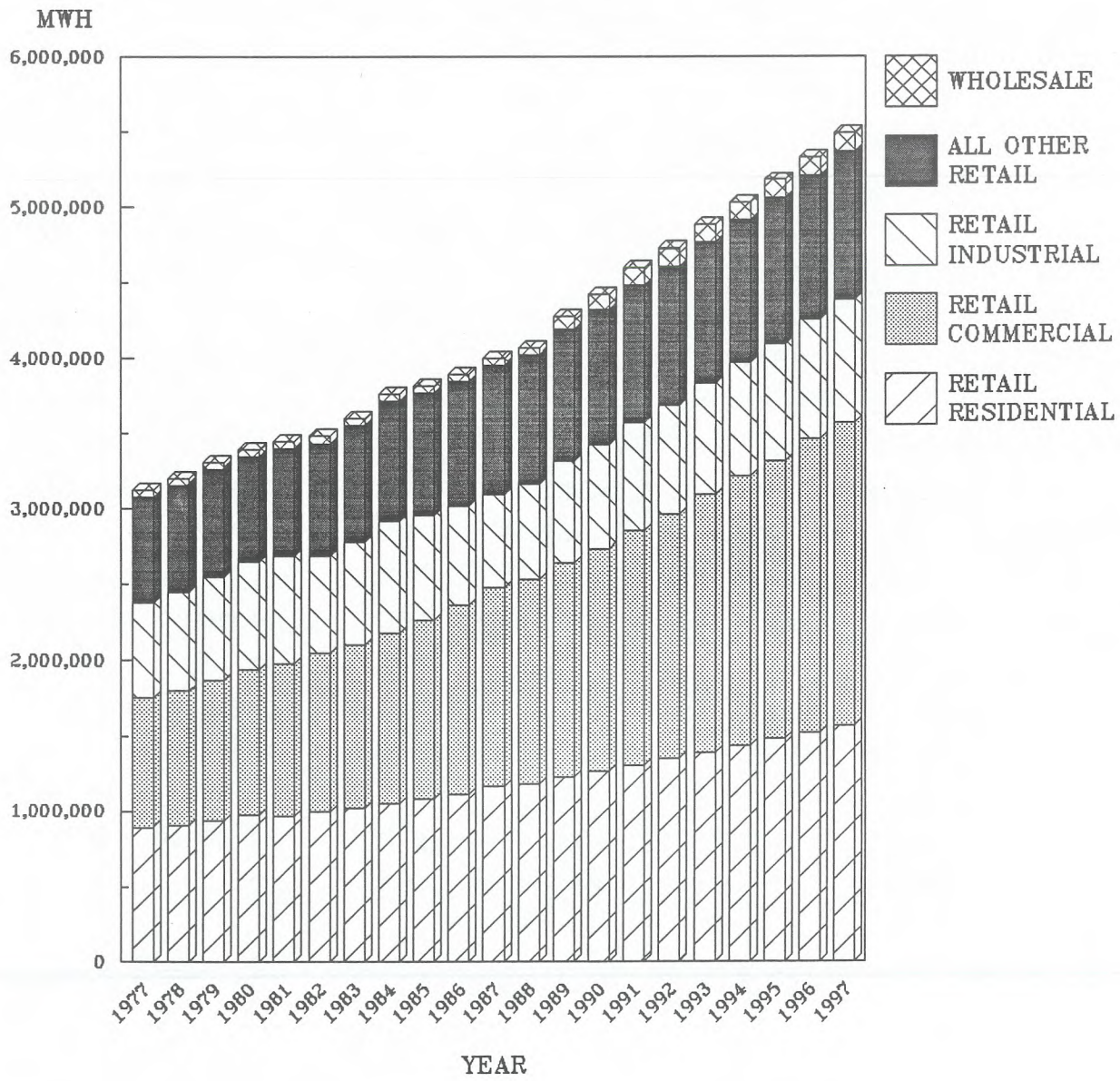
Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

TABLE 12.1B
Number of customer by Sector
El Paso Electric Company — Texas Only

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	113,701	10,773	37	1,395	2
1978	120,074	11,290	32	1,470	2
1979	125,263	11,647	33	1,516	2
1980	129,798	11,944	33	1,550	2
1981	133,627	12,337	33	1,578	2
1982	136,642	12,746	32	1,609	2
1983	140,075	13,077	32	1,650	2
1984	145,748	13,561	32	1,636	2
1985	150,255	14,271	38	1,647	2
1986	155,099	14,796	37	1,678	2
1987	160,010	15,324	37	1,749	2
1988	165,191	15,870	39	1,792	2
1989	165,196	16,402	40	1,834	2
1990	169,334	16,951	41	1,877	2
1991	173,252	17,519	42	1,921	2
1992	177,345	18,105	43	1,966	2
1993	181,841	18,712	44	2,012	2
1994	186,289	19,338	45	2,059	2
1995	190,515	19,986	46	2,108	2
1996	194,743	20,656	48	2,157	2
1997	199,999	21,347	49	2,208	2

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 12.1A
EL PASO ELECTRIC COMPANY
TOTAL ANNUAL SALES BY SECTOR (MWH)



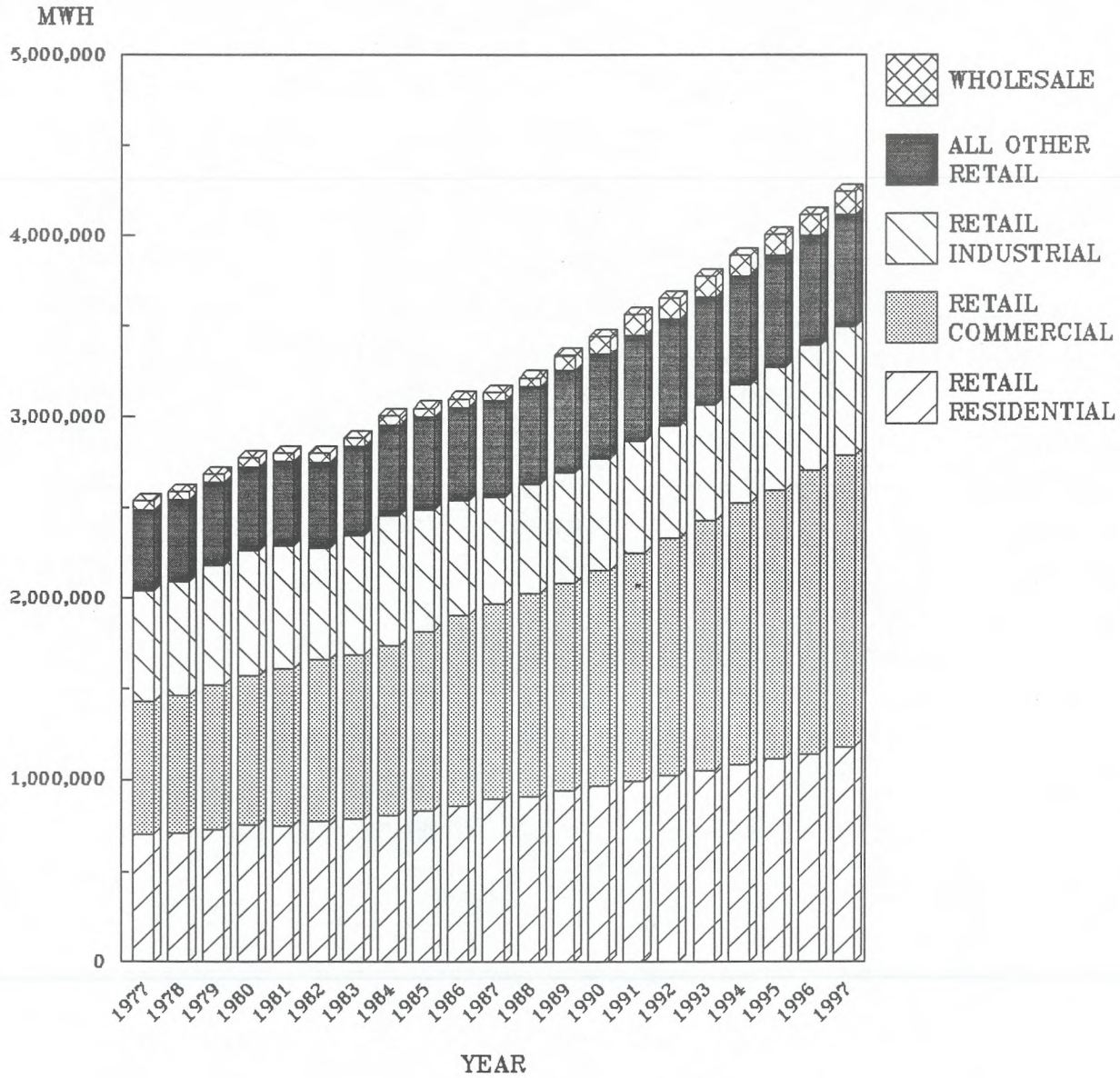
SOURCE: TABLE 12.2A

TABLE 12.2A
Annual Sales by Sector
El Paso Electric Company — Total System
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	893,506	856,648	627,437	701,076	47,127	3,125,794
1978	908,283	886,445	651,351	710,492	44,973	3,201,544
1979	937,856	927,989	682,162	712,658	45,264	3,305,929
1980	972,069	961,594	710,136	704,348	48,042	3,396,189
1981	966,383	1,011,775	702,324	719,171	48,908	3,448,561
1982	995,448	1,051,825	634,008	748,519	53,145	3,482,945
1983	1,018,681	1,082,480	677,116	777,852	44,553	3,600,682
1984	1,048,062	1,126,071	741,133	797,588	47,090	3,759,944
1985	1,080,572	1,179,026	696,659	810,978	47,910	3,815,145
1986	1,114,623	1,244,476	658,490	831,329	44,991	3,893,909
1987	1,168,327	1,305,149	621,104	863,423	44,420	4,002,423
1988	1,183,733	1,346,738	631,213	866,278	45,100	4,073,062
1989	1,230,960	1,407,002	674,247	884,548	82,482	4,279,239
1990	1,266,813	1,466,881	690,182	902,758	97,879	4,424,513
1991	1,305,779	1,549,654	712,347	918,117	114,831	4,600,728
1992	1,349,446	1,613,686	722,986	925,063	117,666	4,728,847
1993	1,393,267	1,699,526	738,248	938,465	117,839	4,887,345
1994	1,436,868	1,779,100	756,966	943,837	118,196	5,034,967
1995	1,480,211	1,832,574	779,675	972,151	118,553	5,183,164
1996	1,523,574	1,939,332	793,000	956,021	119,053	5,330,980
1997	1,569,496	1,997,605	816,790	984,702	122,666	5,491,259

Note: Annual sales figures are prior to demand-side adjustments.

FIGURE 12.1B
EL PASO ELECTRIC COMPANY
ANNUAL SALES IN TEXAS BY SECTOR (MWH)



SOURCE: TABLE 12.2B

TABLE 12.2B
Annual Sales by Sector
El Paso Electric Company — Texas Only
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	704,838	724,917	609,302	449,432	47,127	2,535,616
1978	709,908	748,458	632,201	456,275	44,973	2,591,815
1979	730,724	787,054	661,745	460,148	45,264	2,684,935
1980	756,898	815,108	692,307	460,757	48,042	2,773,112
1981	751,005	856,221	683,923	464,397	48,908	2,804,454
1982	773,512	883,788	617,965	475,450	53,145	2,803,860
1983	788,761	898,943	659,333	490,923	44,553	2,882,513
1984	807,943	929,637	718,963	500,413	47,090	3,004,046
1985	832,947	983,115	673,866	510,994	47,910	3,048,832
1986	859,579	1,043,447	634,456	517,136	44,991	3,099,609
1987	893,765	1,073,035	591,697	534,840	44,420	3,137,757
1988	910,224	1,111,992	605,313	542,284	45,100	3,214,913
1989	940,215	1,144,202	607,904	562,311	82,482	3,337,114
1990	965,456	1,190,477	613,620	574,063	97,879	3,441,495
1991	992,090	1,257,829	615,623	583,931	114,831	3,564,304
1992	1,022,277	1,308,110	621,405	587,929	117,666	3,657,387
1993	1,052,852	1,375,731	634,817	598,431	117,839	3,779,670
1994	1,083,378	1,439,234	651,532	601,517	118,196	3,893,857
1995	1,116,125	1,482,512	671,078	619,562	118,553	4,007,830
1996	1,142,497	1,564,738	683,460	609,008	119,053	4,118,756
1997	1,176,995	1,611,774	703,964	627,279	122,666	4,242,678

Note: Annual sales figures are prior to demand-side adjustments.

Residential sales grew fairly steadily over the past 10 years at an average rate of 2.4 percent per year to reach 893,765 MWH in 1987. EPE projects increasing growth in the residential sector at a 2.8 percent rate per year through 1997.

The remaining retail sales are composed primarily of sales to municipalities, for street lighting and other purposes. These sales amounted to 534,840 MWH in 1987, 17 percent of the total sales for that year. Substantial growth is not expected.

EPE projects sales within the wholesale sector to increase at a rate of 10.7 percent per annum through 1997, from 44,420 MWH in 1987 to 122,666 MWH in 1997. No off-system sales are reported or projected.

Total sales in Texas amounted to 3,137,757 MWH in 1987. Growth in the total sales averaged nearly 2.2 percent from 1977 through 1987. The Company expects sales to grow at an average annual rate of about 3 percent through 1997 to reach 4,242,678 MWH in that year.

Peak Demand. Over the period from 1977 through 1987, EPE experienced an average 2.4 percent annual growth in peak demand to reach 829 MW in 1987 as shown in Figure 12.2, *Net System Capacity and Peak Demand - Texas Portion*. The Company expects growth through 1997 to occur at about 3.1 percent annually. EPE anticipates a peak demand of 1,137 MW in 1997.

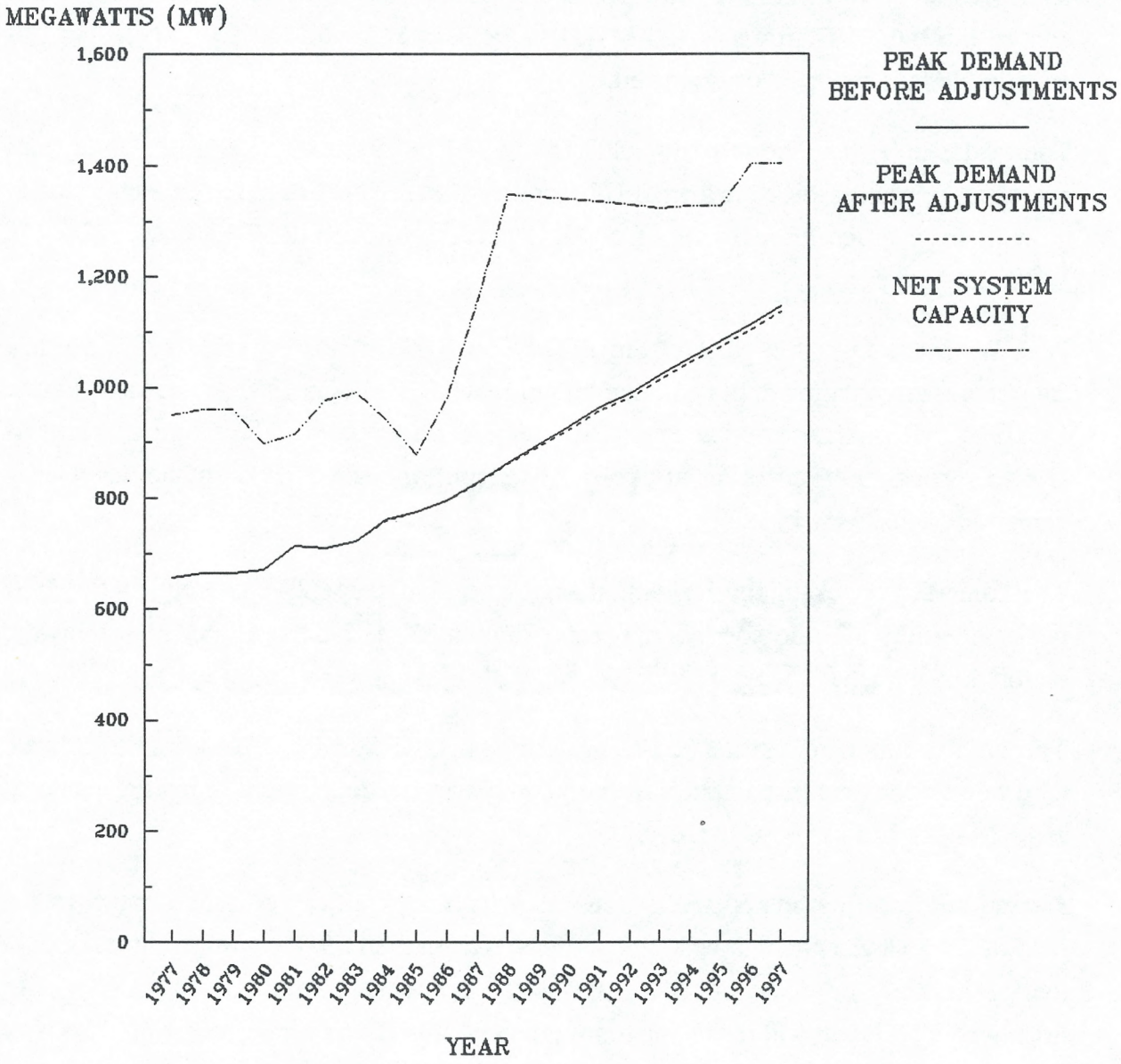
The coincident peak of the residential sector accounted for 29.5 percent of the 1987 peak demand while the commercial sector demanded 37.5 percent, and the industrial sector, 15.6 percent.

The 1987 commercial sector's non-coincident peak of 272.3 MW represents the greatest load of any one sector, compared to non-coincident residential and industrial peaks at 264.8 MW and 116 MW, respectively.

Demand-Side Adjustments. EPE states that its energy efficiency goal is improve the load factor to lower the unit cost of electricity. Given the EPE current inventory of base load generating capacity, energy supply will be adequate into the late 1990s. An improved load factor will result in a more efficient utilization of the generating units.

The Company offers residential customers energy audits and suggestions on how to improve energy efficiency in their homes. For commercial customers, EPE promotes the concept of cool storage in building construction, provides free on-site energy efficiency

FIGURE 12.2
EL PASO ELECTRIC COMPANY – TEXAS PORTION
NET SYSTEM CAPACITY AND PEAK DEMAND



lighting audits, and helps to size and evaluate the operating cost of heating and air conditioning systems.

EPE assumes that the historic program impacts are embedded in the historical data and states that these program impacts are small. Projections of savings due to conservation and load management activities are 1 MW in 1988 increasing to 9 MW in 1997. The effect of demand-side adjustments may be seen in Figure 12.2 as the difference in peak demand before and after adjustments.

12.2 CAPACITY PLAN

Efficiency Improvements to Supply. The Company is pursuing two programs, one to improve the efficiency of its generation units and one to purchase more efficient transformers for its distribution network.

Current Installed Capacity. EPE operates 19 generation units with a total installed capacity in 1987 of 1,303 MW. Almost 61 percent of the capacity is fueled by gas, about 31 percent by nuclear fuel and 8 percent by coal. Table 12.3, *Installed Capacity by Fuel Type*, shows projections of 55 percent of the installed capacity in 1997 being fired by gas, 7 percent by coal, and 38 percent by nuclear power.

At the close of 1987, EPE carried a production plant acquisition cost of $0.8 billion and a book value of $0.7 billion.

Net System Capacity. Installed capacity plus the net of firm sales and purchases yields net system capacity. As shown in Table 12.4, *Net System Capacity and Reserve Margins*, the EPE system had a net system capacity of 1,160 MW in 1987. The Company expects to achieve a net system capacity of 1,403 MW in 1997. The reserve margin would fall from 40 percent in 1987 to 23 percent in 1997, if projections hold.

Net Generation. Figure 12.3, *Net Generation by Fuel Type*, shows projections of nuclear power growing from about 48 percent of total net generation in 1987 to nearly 70 percent in 1997. The Palo Verde nuclear plant in Arizona provided 2,290,624 MWH of electricity in 1987 and the Company projects output to grow to 3,906,900 MWH in 1997. Gas-use projections show a decline from providing 37 percent of the energy in 1987 to 18 percent, or 1,010,600 MWH, in 1997. Coal generation will remain fairly constant and fall

TABLE 12.3
Installed Capacity by Fuel Type
El Paso Electric Company
(MW)

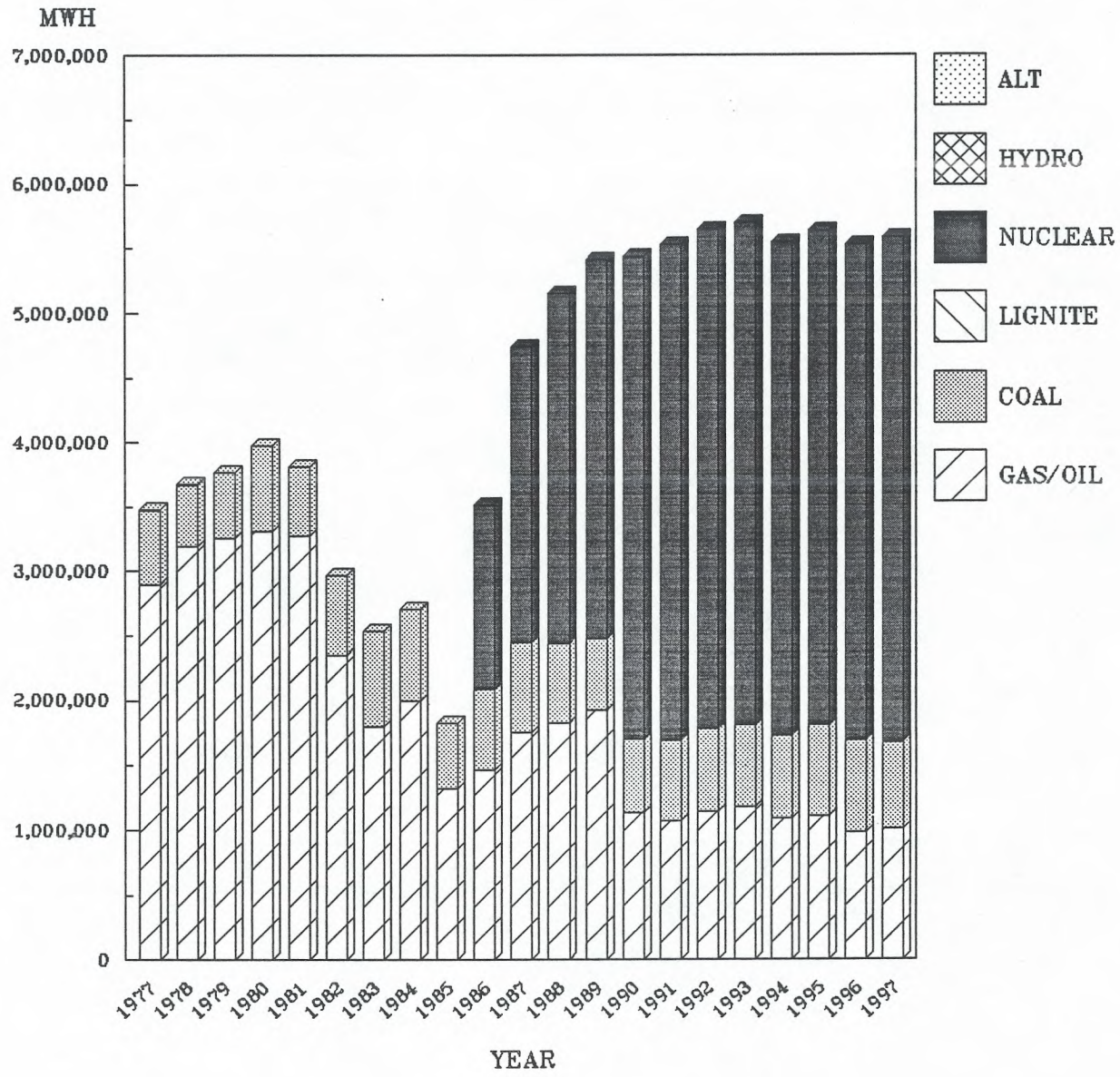
Year	Natural Gas and Fuel Oil	Coal	Lignite	Nuclear	Hydro	Alternate Sources	Total Installed Capacity
1977	839	111	0	0	0	0	950
1978	849	111	0	0	0	0	960
1979	849	111	0	0	0	0	960
1980	888	111	0	0	0	0	999
1981	879	111	0	0	0	0	990
1982	879	111	0	0	0	0	990
1983	879	112	0	0	0	0	991
1984	879	111	0	0	0	0	990
1985	879	110	0	0	0	0	989
1986	793	110	0	200	0	0	1,103
1987	793	110	0	400	0	0	1,303
1988	793	110	0	600	0	0	1,503
1989	793	110	0	600	0	0	1,503
1990	793	110	0	600	0	0	1,503
1991	793	110	0	600	0	0	1,503
1992	793	110	0	600	0	0	1,503
1993	793	110	0	600	0	0	1,503
1994	793	110	0	600	0	0	1,503
1995	793	110	0	600	0	0	1,503
1996	868	110	0	600	0	0	1,578
1997	868	110	0	600	0	0	1,578

Note: Alternate sources do not include cogeneration.

TABLE 12.4
Net System Capacity and Reserve Margins
El Paso Electric Company
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	657	657	950	0	0	950	44.6
1978	665	665	960	0	0	960	44.4
1979	664	664	960	0	0	960	44.6
1980	670	670	999	0	100	899	34.1
1981	713	713	990	0	75	915	28.3
1982	709	709	990	0	14	976	37.7
1983	722	722	991	0	0	991	37.3
1984	760	760	990	0	49	941	23.9
1985	775	775	989	0	111	878	13.3
1986	796	796	1,103	0	123	980	23.1
1987	829	828	1,303	0	143	1,160	40.1
1988	864	862	1,503	0	154	1,349	56.5
1989	897	893	1,503	0	159	1,344	50.5
1990	929	924	1,503	0	163	1,340	45.0
1991	964	958	1,503	0	168	1,335	39.4
1992	988	981	1,503	0	174	1,329	35.5
1993	1,022	1,014	1,503	0	179	1,324	30.6
1994	1,052	1,044	1,503	0	175	1,328	27.2
1995	1,082	1,073	1,503	0	175	1,328	23.8
1996	1,114	1,104	1,578	0	175	1,403	27.1
1997	1,148	1,137	1,578	0	175	1,403	23.4

FIGURE 12.3
EL PASO ELECTRIC COMPANY
NET GENERATION BY FUEL TYPE (MWH)



ALT – Generation from facilities using alternate energy sources. Does not include hydro or cogeneration

as a percentage of total generation from 14.6 percent in 1987 to somewhat under 12 percent in 1997.

System Expansion. EPE expects Palo Verde Unit 3 to operate in 1988, adding 200 MW to the system. The only other addition to capacity planned by EPE for the forecast period involves a gas-powered combustion turbine of 75 MW, scheduled for EPE use in 1996.

Certain EPE power plant sites were initially reserved for generating units not now planned to be installed over the next ten years. However, the potential for adding initially planned capability is limited by financial, water, environmental, and transmission requirements, site layout, and fuel supply. Specific units, listed in Chapter 1 of this volume under "Potential Additions at Existing Sites," may also be limited by ambient air quality standards, station water balance, cooling pond temperature, water discharge permit, and solid waste handling and storage. Site specific studies would be needed to determine the best technology and size of any unit additions.

EPE will complete two 345 KV transmission line projects in 1988 and 1989 totaling 320 miles in New Mexico at a cost of nearly $74 million.

CHAPTER THIRTEEN

TEXAS-NEW MEXICO POWER COMPANY

Texas-New Mexico Power Company, a public utility, renders electrical service in portions of Texas and New Mexico. In New Mexico, the Company both generates and purchases electricity for transmission and distribution in nine incorporated towns and surrounding areas. In Texas, TNP serves 80 incorporated towns and surrounding territory in five noncontiguous areas. TNP purchases all of its electricity for transmission and distribution to its customers in Texas, where, except for the Panhandle Division, it operates as a member of ERCOT. The suppliers of purchased power are Houston Lighting and Power Company, Union Carbide Corporation, and Capitol Cogeneration in the Southeast Division; West Texas Utilities and TU Electric in the Western Division; Southwestern Public Service Company in the Panhandle Division; TU Electric in the Central Division; TU Electric in the Northeast Division.

TNP is a subsidiary of Texas-New Mexico Power Enterprises, an investor-owned company. TNP's Revenues for 1987 totaled $360,842,000, while total assets as of December 31, 1987 were $402,739,000. The Company's capital structure at that date was comprised of 49.4 percent common equity, 6 percent preferred stock, and 44.6 percent long-term debt.

TNP reports a 1987 peak demand for its Texas operations of 955 MW. Texas sales, 4,723,482 MWH, amount to 78 percent of all TNP system sales of 6,023,251 MWH in 1987. In the following analysis, all data refers to the Texas portion of the system except where specified otherwise.

13.1 DEMAND FORECAST

Forecasting Methodology. TNP forecasts KWH sales using a multiple regression model for residential and commercial customers, along with interviews of industrial customers. The forecast is modified by each of the Company's five Divisions according to particular knowledge of economic conditions, prices of alternative energy sources, probable actions of competitors, population growth, intentions of farmers, and so forth. An average load factor for each customer class applied to the sales forecast yields a non-coincidental peak prediction. To calculate the coincident peak load for the ERCOT portion of TNP's

system an average coincidence factor is determined for each interconnection with a power supplier and applied to the non-coincidental peak. Non-coincidental KW peaks of the non-ERCOT systems are added to arrive at peaks for Total Texas or Total System data categories.

Number of Customers. As shown in Table 13.1, *Number of Customers by Sector*, in 1987 TNP provided electric service to 136,610 residential customers. The historical data for the period from 1977 through 1987 reflect an average annual growth rate of 3.2 percent for this class of customers. TNP expects a 2.6 percent average annual growth rate over the forecast period. The Company served 24,531 commercial customers in 1987. The historical and projected average growth rates for the commercial sector are 3.8 percent and 2.5 percent per annum, respectively. The industrial sector has declined since 1986 but is expected to remain a flat 163 customers through 1997.

Annual Sales. The stable industrial base in TNP's Texas service areas will provide only a 1 percent growth in total sales according to Company expectations. Figure 13.1, *Annual Sales by Sector*, shows that in 1987 the industrial sector purchased 1,795,693 MWH, about 38 percent of total Company sales in Texas. By 1997, the industrial sector will take only 34 percent of total sales. Growth of the commercial sector, at 3.3 percent annually on average, leads all other sectors, but commercial sales will remain in third place through the forecast period. Residential sales will surpass industrial in 1992 to become the largest class customer, taking 37.4 percent of total sales in 1997, up from 1977's 31.2 percent.

The remaining retail sales are composed primarily of sales to municipalities, for street lighting and other purposes. These sales amounted to 99,424 MWH in 1987, 2 percent of the total sales for that year. The growth rate for this class is expected to average 1.8 percent per year over the forecast period.

TNP projects sales within the wholesale sector to increase at a rate of 2.3 percent per annum through 1997, down from the 3.6 percent seen during the period from 1977 through 1987. In 1987, 18,184 MWH was purchased wholesale from the company.

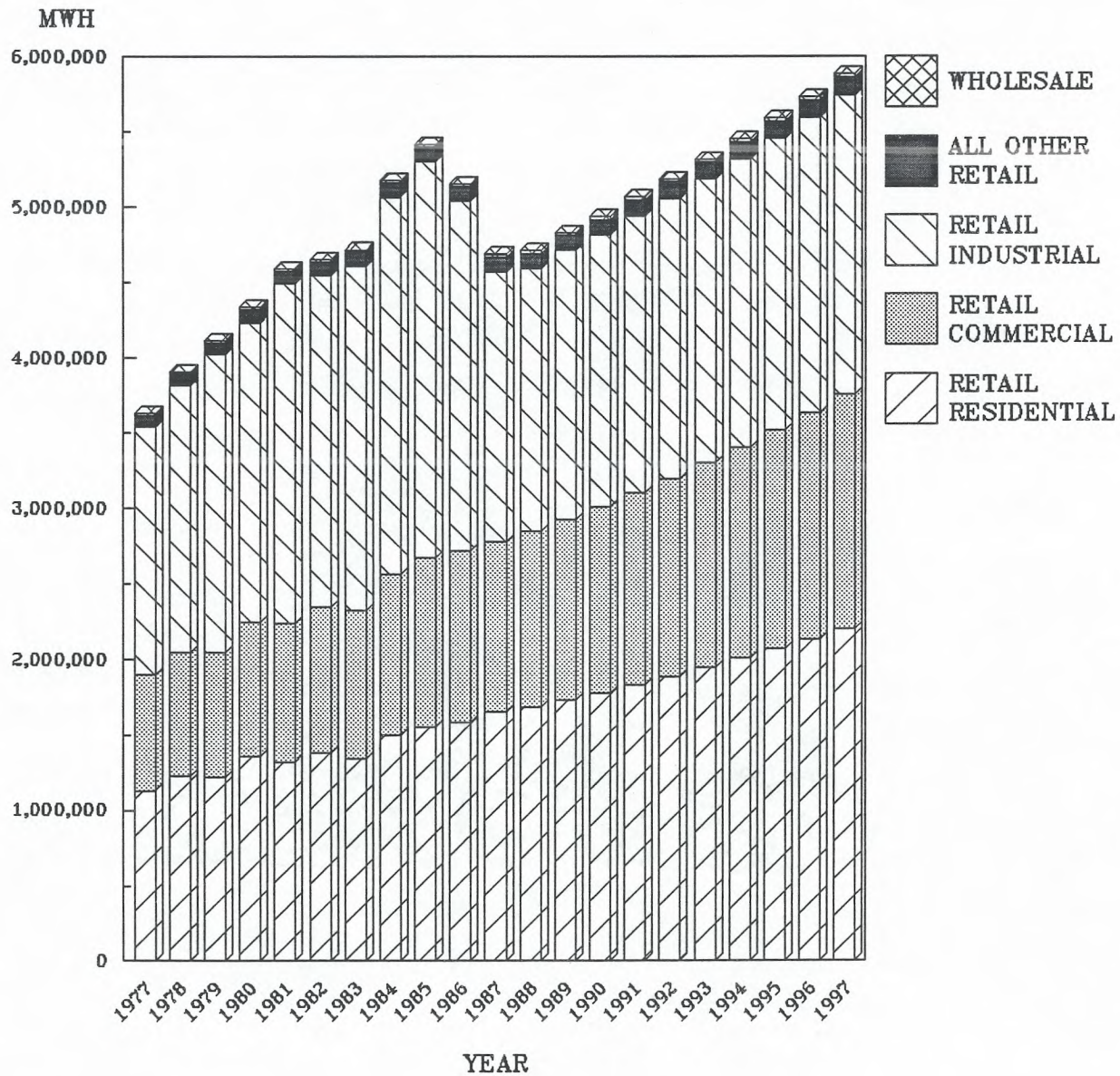
Total sales amounted to 4,690,343 in 1987. Although growth in the total sales averaged nearly 2.6 percent from 1977 through 1987, the 1987 figure represents a decline of some 728,000 since its highest sales year, 1985. The company expects sales to grow at an average annual rate of about 2.3 percent through 1997, surpassing the 1985 peak in 1994.

TABLE 13.1
Number of customer by Sector
Texas–New Mexico Power Company — Texas Only

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale
1977	99,472	17,429	141	169	1
1978	103,969	17,915	155	169	1
1979	108,113	18,498	162	178	1
1980	111,824	19,444	178	178	1
1981	116,480	20,064	179	188	1
1982	120,083	20,734	191	195	1
1983	125,487	21,472	170	210	1
1984	130,659	22,573	180	209	1
1985	133,201	23,485	182	209	1
1986	134,169	24,143	189	208	1
1987	136,610	24,531	164	208	2
1988	139,825	25,105	163	208	2
1989	142,810	25,672	163	208	2
1990	146,250	26,291	163	208	2
1991	149,906	26,933	163	208	2
1992	153,954	27,615	163	208	2
1993	158,154	28,317	163	208	2
1994	162,505	29,053	163	208	2
1995	167,024	29,813	163	208	2
1996	171,725	30,605	163	208	2
1997	176,613	31,425	163	208	2

Note: All other retail includes cotton gin, irrigation, street lighting, municipalities, and miscellaneous customers.

FIGURE 13.1
TEXAS – NEW MEXICO POWER COMPANY
ANNUAL SALES IN TEXAS BY SECTOR (MWH)



SOURCE: TABLE 13.2

TABLE 13.2
Annual Sales by Sector
Texas–New Mexico Power Company
(MWH)

Year	Retail Residential	Retail Commercial	Retail Industrial	All Other Retail	Wholesale	Total Sales at the Meter
1977	1,132,837	762,875	1,645,294	77,250	12,752	3,631,008
1978	1,231,104	811,352	1,775,716	79,976	13,864	3,912,012
1979	1,221,113	824,529	1,976,767	80,844	12,894	4,116,147
1980	1,356,202	891,877	1,987,887	85,851	14,996	4,336,813
1981	1,324,575	909,215	2,260,601	86,819	13,432	4,594,642
1982	1,380,476	964,692	2,203,493	92,978	13,608	4,655,247
1983	1,341,938	980,703	2,288,955	95,736	14,104	4,721,436
1984	1,500,860	1,062,685	2,503,934	97,681	15,398	5,180,558
1985	1,555,402	1,112,703	2,632,844	99,793	17,385	5,418,127
1986	1,585,108	1,126,041	2,327,090	101,184	17,848	5,157,271
1987	1,653,929	1,123,113	1,795,693	99,424	18,184	4,690,343
1988	1,685,346	1,158,662	1,750,314	102,851	16,656	4,713,829
1989	1,727,086	1,195,883	1,790,894	104,666	17,336	4,835,865
1990	1,774,987	1,232,972	1,806,364	106,675	18,015	4,939,013
1991	1,826,013	1,271,641	1,845,039	108,408	18,696	5,069,797
1992	1,882,715	1,312,772	1,863,433	110,145	19,377	5,188,442
1993	1,941,697	1,355,705	1,890,505	111,887	20,057	5,319,851
1994	2,002,967	1,400,574	1,916,135	113,632	20,737	5,454,045
1995	2,066,744	1,447,533	1,941,764	115,382	21,417	5,592,840
1996	2,133,153	1,496,606	1,967,393	117,137	22,098	5,736,387
1997	2,202,325	1,548,959	1,993,022	118,896	22,779	5,885,981

Note: Annual sales figures are prior to demand-side adjustments.

Peak Demand. Over the period from 1977 through 1987, TNP experienced 2.6 percent annual growth in peak demand, although Figure 13.2, *Net System Capacity and Peak Demand*, shows peak demand actually fell 65 MW from 1986 to 1987. However, the utility expects growth through 1997 to occur at about 2.8 percent annually. TNP anticipates a peak demand of 1,253 MW in 1997.

The coincident peak of the residential sector accounts for 50 percent of the 1987 peak demand; the commercial sector, 23.6 percent; the industrial sector 24 percent; other retail 1.6 percent; and wholesale, less than one percent.

The 1987 residential non-coincident peak of 525 MW represents the greatest load of any one sector, compared to non-coincident commercial and industrial peaks at 308 MW and 257 MW, respectively.

Demand-Side Adjustments. TNP states that its energy efficiency goal is to improve annual system load factor. For all-electric home owners, the Company promotes strategic conservation and peak shaving techniques through increased thermal integrity, reduced equipment requirements, and higher efficiency equipment. To encourage irrigation customers to restrict their usage during on-peak hours, TNP offers reduced energy rates for those shifting to off-peak hours.

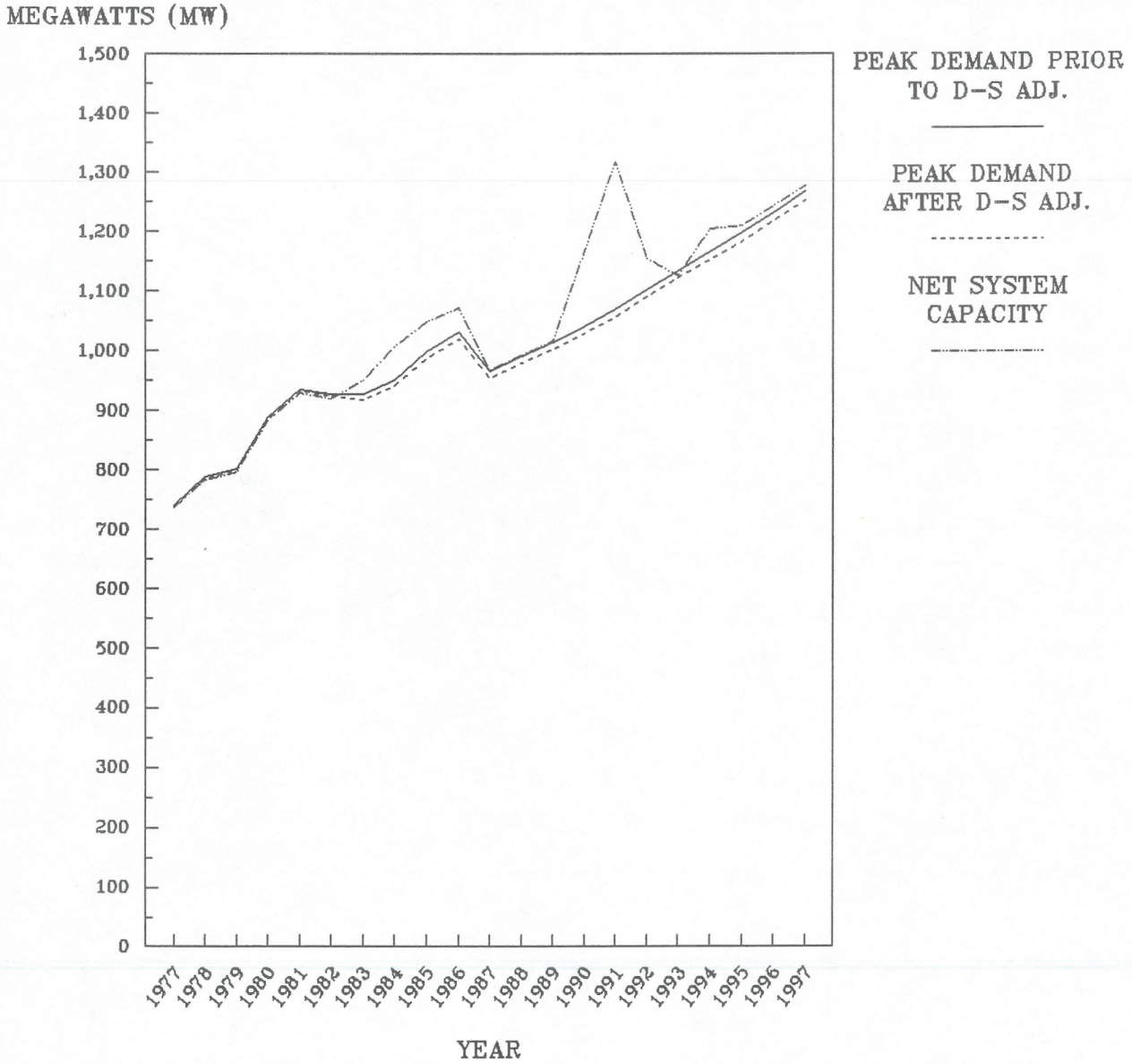
TNP reports 1987 peak demand is 10 MW lower than it would have been, due to conservation and load management practices. The total reductions in peak capacity grow from 2 MW in 1977 to the projected 15 MW in 1997. The effects of the adjustments to demand may be seen in Figure 13.2 as the difference between Peak Demand Before Adjustments and Peak Demand After Adjustments.

13.2 CAPACITY PLAN

Efficiency Improvements to Supply. The Company instituted more efficient purchasing policies for distribution transformers and expects savings from that.

Current Installed Capacity. TNP generates no electricity in Texas. The Company purchases all of the electricity it needs to supply its customers in Texas. As such, the Company's reserve margins as shown in Table 13.3, *Net System Capacity and Reserve Margins*, are not indicative of TNP's system reliability.

FIGURE 13.2
TEXAS - NEW MEXICO POWER COMPANY
NET SYSTEM CAPACITY AND PEAK DEMAND



D-S ADJ. is Demand-Side Adjustments

TABLE 13.3
Net System Capacity and Reserve Margins
Texas–New Mexico Power Company
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	740	738	0	736	0	736	0.0
1978	788	785	0	783	0	783	0.0
1979	803	800	0	797	0	797	0.0
1980	888	885	0	883	0	883	0.0
1981	935	932	0	930	0	930	0.0
1982	927	923	0	919	0	919	0.0
1983	928	918	0	951	0	951	3.6
1984	950	940	0	1,007	0	1,007	7.1
1985	998	986	0	1,048	0	1,048	6.3
1986	1,030	1,019	0	1,072	0	1,072	5.2
1987	965	955	0	968	0	968	1.4
1988	991	980	0	993	0	993	1.3
1989	1,014	1,003	0	1,015	0	1,015	1.2
1990	1,041	1,030	147	1,021	0	1,168	13.4
1991	1,069	1,057	295	1,024	0	1,319	24.7
1992	1,103	1,091	295	860	0	1,155	5.8
1993	1,134	1,121	295	830	0	1,125	0.3
1994	1,165	1,152	442	763	0	1,205	4.6
1995	1,198	1,184	589	620	0	1,209	2.1
1996	1,232	1,218	589	654	0	1,243	2.1
1997	1,268	1,253	589	689	0	1,278	2.0

System Expansion. TNP does plan to construct four lignite plants in Robertson County, Texas with nameplate ratings of 160 MW each. Construction of Unit One began in December 1987. Construction on Unit Two is scheduled to begin in September 1988, and Units Three and Four in 1991 and 1992; however, these latter two units are subject to further review by the PUCT. Completion dates are in 1990, 1991, 1994, and 1995, respectively. Unit One is expected to cost $253,517,000, or $1,401.50 per KW installed. TNP completed two 138 KV transmission line projects in 1987 and plans to complete one more in 1988, a 33-mile line in Bosque and Hamilton counties for $2,800,000. Also beginning in 1988, 18 miles of 345 KV line in Robertson County is scheduled for completion in 1989 at a cost of $10,629,500.

CHAPTER FOURTEEN

BRAZOS ELECTRIC POWER COOPERATIVE

Brazos Electric Power Cooperative is a rural electric cooperative engaged in the generation and transmission of electricity. BEPC sells only wholesale power, to member-owner distribution rural electric cooperatives and through interconnection agreements to certain other customers, including seven cities and Texas A & M University. BEPC's member-cooperatives have individual certified authority to render electric service covering all or part of 57 counties in Texas. The Cooperative is a member of the Texas Municipal Power Pool and ERCOT.

BEPC reported a peak demand of 762 MW in 1987. Annual sales for the Cooperative were projected to be 3,083,436 MWH in that same year. BEPC currently has an installed capacity of 467 MW and generates its electricity with natural gas.

14.1 DEMAND FORECAST

Forecasting Methodology. In formulating its forecasts BEPC employs econometric models developed by its staff and its consultant Dr. Ray Perryman of Baylor University. Models are developed for each of the member cooperatives, municipalities served by BEPC, and Texas A & M University. These models are combined to formulate the forecasts for the Cooperative.

Number of Customers. BEPC provides wholesale electric service to 20 member cooperatives, seven municipalities, and Texas A & M University. These 28 customers comprise the total firm sales of Brazos over the forecast period.

Annual Sales. In 1987, BEPC reported projected sales of 3,083,436 MWH. All sales were made to the wholesale sector. Figure 14.1, *Annual Wholesale Sales*, shows that over the period 1977 through 1987, sales grew at an average annual compound rate of 7 percent. Over the forecast period, the Cooperative anticipates growth of 4.6 percent per annum.

Peak Demand. Historically, BEPC experienced a growth in peak demand of 7.2 percent per year for the ten-year period beginning in 1977. As shown in Figure 14.2, *Net System*

FIGURE 14.1
BRAZOS ELECTRIC POWER COOPERATIVE
ANNUAL WHOLESALE SALES (MWH)

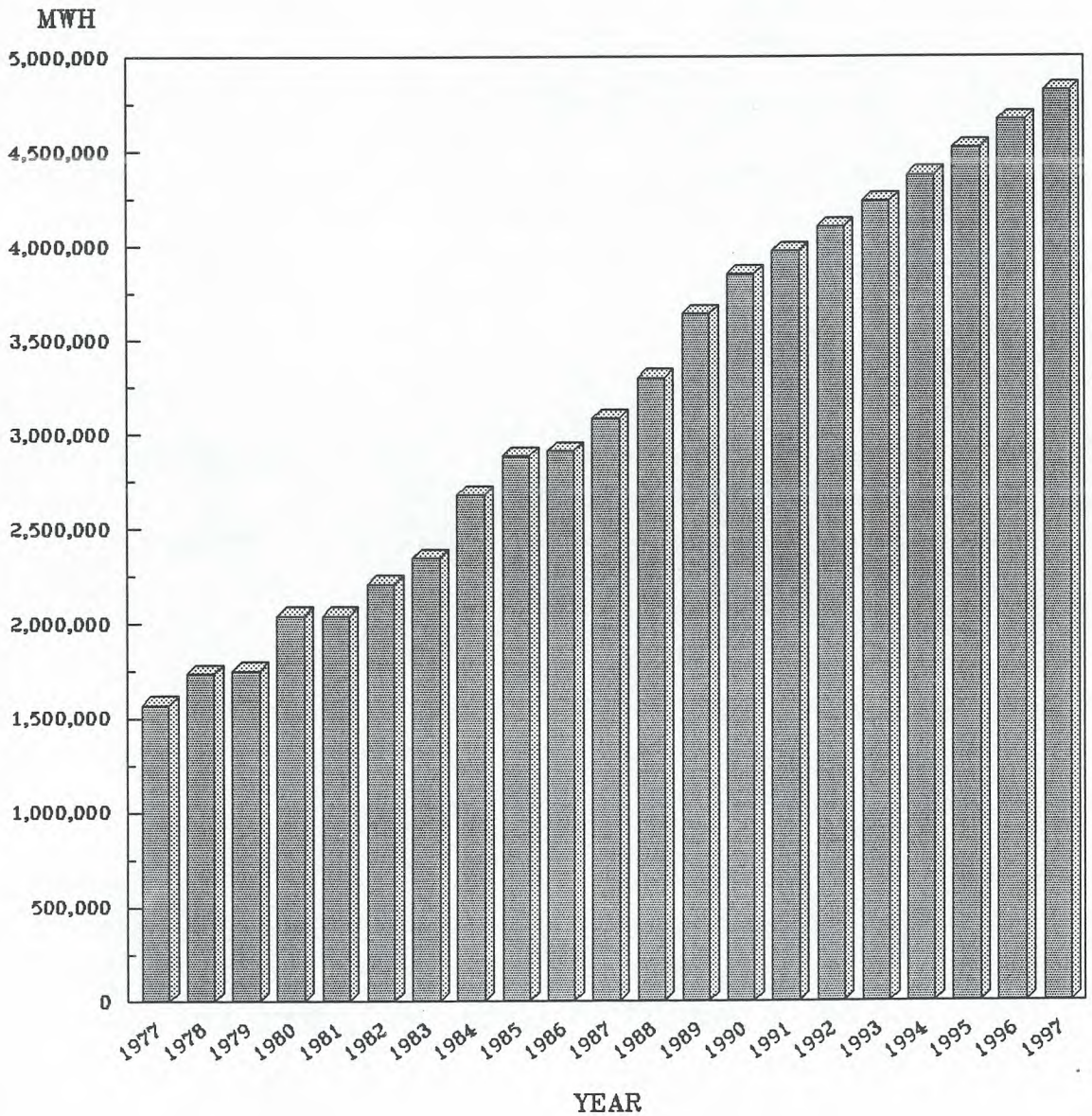
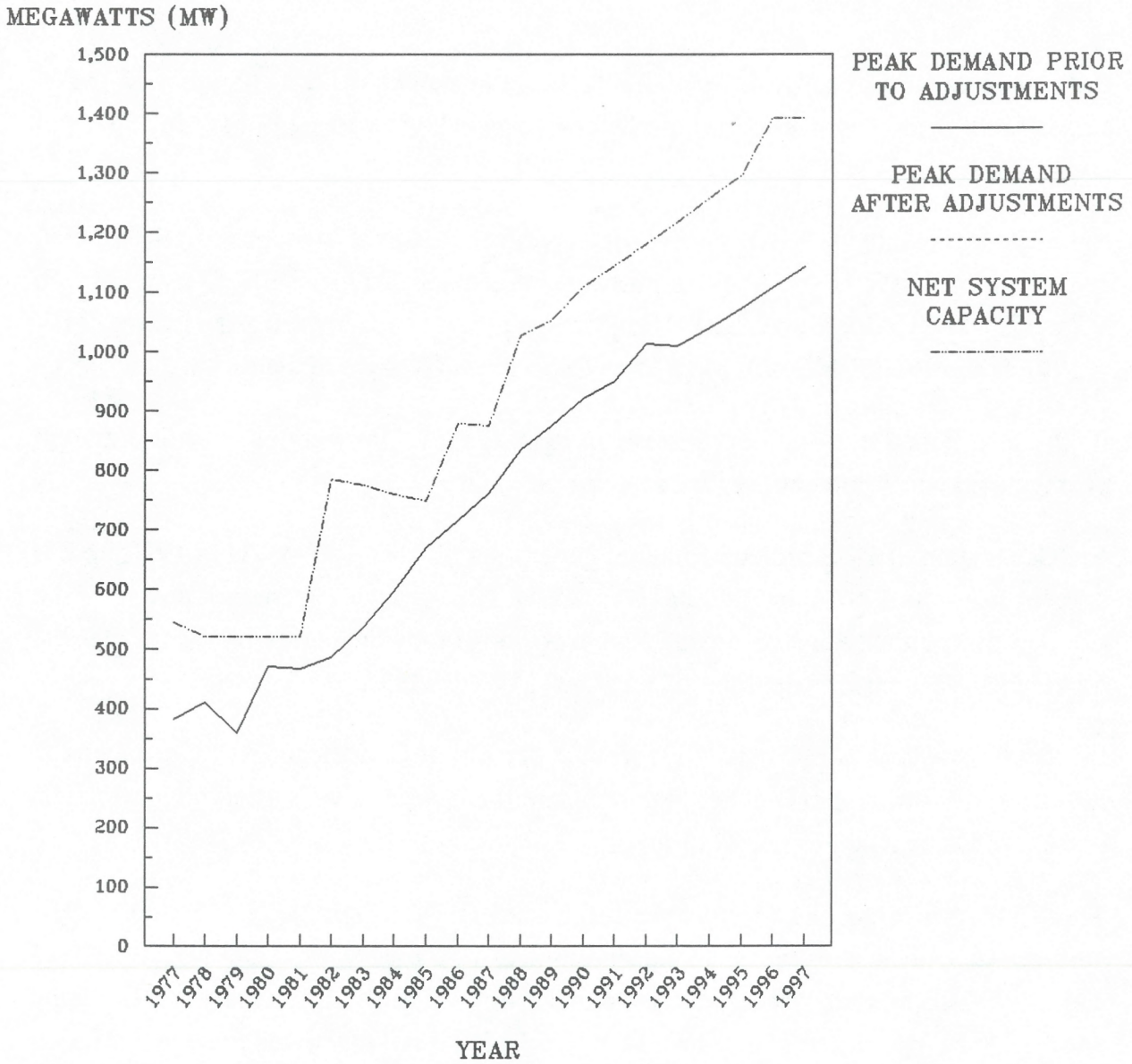


FIGURE 14.2
BRAZOS ELECTRIC POWER COOPERATIVE
NET SYSTEM CAPACITY AND PEAK DEMAND



Capacity and Peak Demand, peak demand rose from 382 MW in the base year to the 1987 figure of 762 MW. The Cooperative expects growth to occur at an average rate of 4.5 percent annually over the next decade, resulting in a peak demand of 1,143 MW in 1997.

Demand-Side Adjustments. At this time BEPC reports no demand-side adjustments. A Load Management Study is currently in progress and is due to be completed in late 1988.

14.2 CAPACITY PLAN

Current Installed Capacity. In 1987, BEPC had an installed capacity of about 467 MW, all gas-fired. Projections indicate installed capacity will grow to 1,143 MW in 1997, still all gas-fired.

Net System Capacity. The net system capacity for the BEPC system grew to 876 MW in 1987 from 545 MW in 1977. Firm purchases are made from the BEPC member San Miguel Electric Cooperative. BEPC projections indicate capacity will grow to 1,393 MW in 1997 as shown in Table 14.1, *Net System Capacity and Reserve Margins*.

BEPC maintained a 19 percent reserve margin in 1987. Projections show the margin averaging about 21 percent over the forecast period.

Net Generation. BEPC projects total net generation of 4,996,000 MWH in 1997, up 270 percent from the 1987 figure of 1,345,915 MWH. The growth in generation reflects the Cooperative's anticipation of moving from a position of making net purchases of 608,985 MWH in 1987 to making net sales of 1,117,000 MWH in 1997.

System Expansion. BEPC currently owns 3.8 percent of Comanche Peak Units 1 and 2. However, this ownership is under litigation, and the Cooperative is attempting to sell its portion of Comanche Peak to TU Electric.

The Cooperative has plans to add gas turbines to R. W. Miller Units 4, 5, and 8. The addition to Unit 4 is expected to be operational by January 1990, adding 70 MW of capacity to the system. The Unit 5 addition will be finished by January 1991, adding another 70 MW to the system. The addition to Unit 8 is not scheduled to be in operation until January 1996. This addition will augment the system by 140 MW. BEPC plans to add combined cycle units to R. W. Miller Units 6 and 7. Each of these will add 210 MW to its respective station. The Unit 6 combined cycle unit is expected to be operational by

TABLE 14.1
Net System Capacity and Reserve Margins
Brazos Electric Power Cooperative
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	382	382	491	54	0	545	42.5
1978	412	412	467	54	0	521	26.3
1979	360	360	467	54	0	521	44.6
1980	470	470	467	54	0	521	10.7
1981	466	466	467	54	0	521	11.7
1982	487	487	467	318	0	785	61.1
1983	536	536	467	308	0	775	44.5
1984	596	596	467	294	0	761	27.6
1985	670	670	467	282	0	749	11.7
1986	715	715	467	413	0	879	23.0
1987	762	762	467	409	0	876	14.9
1988	834	834	467	560	0	1,027	23.1
1989	876	876	443	612	0	1,055	20.4
1990	921	921	513	597	0	1,110	20.5
1991	950	950	583	562	0	1,145	20.5
1992	1,014	1,014	793	388	0	1,181	16.4
1993	1,010	1,010	793	426	0	1,219	20.6
1994	1,041	1,041	1,003	255	0	1,258	20.8
1995	1,074	1,074	1,003	295	0	1,298	20.8
1996	1,108	1,108	1,143	250	0	1,393	25.7
1997	1,143	1,143	1,143	250	0	1,393	21.8

January 1992 and Unit 7 by January 1994. These plans are not definite, but represent a feasible generation plan of the potential capacity additions to existing sites. Generation studies are currently in progress.

Included in BEPC's planned construction work are 12 transmission line projects. All of these projects are scheduled to be completed within the next four years. These 12 projects constitute a total of 207 miles of transmission line. All lines will be 138 KV except one at 69 KV. The aggregate cost of the transmission projects is estimated at $68,831,050.

CHAPTER FIFTEEN

OTHER GENERATING UTILITIES

In addition to the utilities discussed in Chapters Two through Fourteen of this volume, 16 other utilities provided information to the PUC. In this chapter, data from these utilities will be treated in the aggregate and will be followed by a brief description of each utility.

15.1 DEMAND FORECAST

Annual Sales. As shown in Table 15.1, *Net Generation and Sales*, the 16 other utilities reported total sales in 1977 of 5,100,563 MWH. Over the period from 1977 through 1987, sales demonstrated an average annual growth rate of 7.4 percent. By 1987, sales had reached 9,788,322 MWH. The majority of total sales, approximately 73 percent, were made to the wholesale sector. Growth is projected to slow considerably. An average growth rate of 2 percent is anticipated through 1997, resulting in total sales of 12,671,307 MWH.

Peak Demand. Over the period from 1977 through 1987, the total peak demand after adjustments of the 16 utilities exhibited an annual growth rate of 3.8 percent. Table 15.2, *Capacity and Demand*, indicates that peak demand after adjustments rose from a total of 1,273 MW in the base year to 1,844 MW in 1987. The projections indicate that growth through 1997 is expected to occur at a rate of 2.9 percent per year, resulting in a total peak demand of 2,445 MW by 1997. Reported demand-side adjustments amounted to 1.1 MW in 1987 and are expected to be 1.8 MW by 1997.

15.2 CAPACITY PLAN

Current Installed Capacity. As shown in Table 15.2, the 16 utilities reported a 1977 total of 988 MW installed capacity. Of this capacity, 82 percent was gas-fired and 18 percent utilized hydroelectric power. Coal and lignite capacity was added beginning in 1982. In 1987, 50 percent of the total 1,719 MW of installed capacity was fired using gas, 30 percent used lignite, 13 percent used hydroelectric power, and 7 percent used coal. Projections show a total installed capacity of 1,866 MW in 1997. Nuclear capacity is projected to be on-line in 1989 and amount to approximately 3 percent of the total installed capacity in 1997. Each of the other fuel types are expected to comprise roughly the same percentage as in 1987.

TABLE 15.1
Net Generation and Sales
Other Texas Utilities
(MWH)

Year	Total Net Generation	Total Net Purchases	Total Retail Sales	Wholesale Sales
1977	3,004,157	2,353,774	1,950,944	3,149,619
1978	2,473,331	3,085,939	2,087,183	3,231,696
1979	2,755,626	3,313,772	2,042,504	3,751,235
1980	2,715,196	3,835,376	2,264,979	3,959,965
1981	2,255,479	4,234,347	2,283,915	3,853,159
1982	4,521,096	4,860,770	2,422,579	6,557,644
1983	4,606,539	5,196,075	2,362,367	6,923,379
1984	4,511,414	5,918,656	2,624,591	7,193,527
1985	5,172,661	5,658,198	2,691,858	7,504,114
1986	5,115,285	5,281,936	2,716,611	7,276,917
1987	5,774,043	5,409,453	2,781,278	7,670,692
1988	5,462,694	5,301,618	2,833,357	7,469,598
1989	5,786,922	5,219,621	2,914,752	7,655,561
1990	5,916,396	5,431,566	2,994,847	7,837,493
1991	6,069,871	5,666,422	3,072,104	8,012,879
1992	6,179,376	5,865,510	3,149,916	8,186,266
1993	6,180,867	6,108,192	3,229,047	8,363,503
1994	6,262,589	6,275,655	3,310,495	8,545,744
1995	6,408,762	6,377,851	3,392,056	8,734,409
1996	6,470,676	6,556,823	3,472,182	8,924,913
1997	6,492,541	6,794,436	3,554,763	9,116,544

TABLE 15.2
Capacity and Demand
Other Texas Utilities
(MW)

Year	Peak Demand Prior to Demand-side Adjustment	Peak Demand After Demand-side Adjustment	Total Installed Capacity	Total Purchased Power	Total Off-System Sales	Net System Capacity	Reserve Margin (percent)
1977	1,273	1,273	988	555	5	1,538	20.8
1978	1,370	1,370	1,093	659	25	1,727	26.0
1979	1,357	1,357	1,090	689	40	1,739	28.2
1980	1,568	1,568	1,090	829	40	1,879	19.8
1981	1,562	1,562	1,090	863	40	1,913	22.5
1982	1,598	1,598	1,524	906	462	1,967	23.1
1983	1,676	1,676	1,503	997	481	2,019	20.5
1984	1,729	1,726	1,537	1,031	475	2,093	21.3
1985	1,792	1,792	1,612	1,126	501	2,237	24.8
1986	1,834	1,833	1,709	1,165	493	2,381	29.9
1987	1,845	1,844	1,719	1,100	486	2,333	26.5
1988	1,935	1,933	1,763	1,077	466	2,374	22.8
1989	1,990	1,988	1,765	1,113	449	2,429	22.2
1990	2,050	2,048	1,840	1,090	430	2,499	22.0
1991	2,106	2,105	1,840	1,117	437	2,520	19.7
1992	2,159	2,157	1,865	1,150	432	2,583	19.7
1993	2,212	2,210	1,866	1,177	427	2,616	18.4
1994	2,270	2,268	1,866	1,198	422	2,642	16.5
1995	2,330	2,328	1,866	1,169	415	2,619	12.5
1996	2,384	2,382	1,866	1,199	407	2,657	11.5
1997	2,447	2,445	1,866	1,236	401	2,700	10.4

Net Generation. As seen in Table 15.1, the total net generation of the sixteen other utilities was reported to be 3,004,157 MWH for 1977. By 1987, net generation had grown to 5,774,043 MWH at an average annual rate of 6.8 percent. A considerably lower rate of growth is expected over the next ten years. Net generation is projected to be 6,492,541 MWH in 1997 with growth occurring at a rate of 1.2 percent per year.

15.3 UTILITY DESCRIPTION

South Texas Electric Cooperative/Medina Electric Cooperative (STEC/MEC), two generating transmission and distribution cooperatives, provide service to customers in 17 counties in southwest Texas. The service area covers approximately 12,000 square miles of mainly unincorporated areas outside small towns and cities. The two cooperatives are power pooling partners which operate under an agreement in which generation of each is pooled and dedicated to combined system load.

The 1987 combined peak demand after adjustments was reported as approximately 227 MW. The cooperatives have a total installed capacity of 112 MW. No additions to installed capacity are planned through 1997. When power is needed, purchases are made from San Miguel Electric Cooperative and Central Power and Light Company.

Total sales amounted to 1,018,859 MWH in 1987 and are expected to grow at a rate of 4.7 percent annually, reaching 1,605,349 MWH in 1997. The largest portion of the total sales are made to the wholesale sector. STEC/MEC is a wholesale supplier to Rio Grande Electric Cooperative.

Sam Rayburn G & T, Inc. (SRGT) is a generation and transmission cooperative headquartered in Nacogdoches, Texas. SRGT is comprised of three member distribution cooperatives, Jasper-Newton Electric Cooperative, Sam Houston Electric Cooperative, and Houston County Electric Cooperative.

The Cooperative projected a 1987 peak demand of 200 MW. Growth is projected to occur at an average 3.3 percent per year, resulting in a peak demand of 277 MW in 1997. This rate of growth is down from the 5 percent per year demonstrated over the previous 10-year period. SRGT meets its demand with capacity from the Nelson 6 coal plant, Sam Rayburn Dam Hydroelectric Project, and supplemental wholesale purchases from Gulf States Utilities. Current installed capacity is reported as 54 MW. Additional coal capacity is

expected to result in an installed capacity of 92 MW. This is expected to remain constant through the forecast period.

Total sales grew at a rate of 5.2 percent per year between 1977 and 1987, beginning with 537,984 MWH in 1977 and ending with a projected 891,271 MWH in 1987. Growth is expected to slow to 3.7 percent annually through 1997, yielding projected total annual sales of 1,287,225 MWH by the end of the forecast period. All SRGT sales are made to the wholesale sector.

SRGT did not generate its own electricity until 1982. In 1987, net generation totaled 304,031 MWH. Annual generation is projected to reach 607,880 MWH by 1997.

San Miguel Electric Cooperative (SMEC) sells all of its power to two member cooperatives, Brazos Electric Power Cooperative and South Texas Electric Cooperative. SMEC reports a peak demand of 391 MW for every year from 1982 through 1997. This is also the reported installed capacity for those same years. Similarly, both total sales and net generation are expected to equal 2,398,000 MWH in every year between 1987 and 1997.

Northeast Texas Electric Cooperative, Inc. (NTEC) is a generation and transmission cooperative headquartered in Longview, Texas. NTEC provides power to six member distribution cooperatives, Bowie-Cass Electric Cooperative, Deep East Texas Electric Cooperative, Panola-Harrison Electric Cooperative, Rusk County Electric Cooperative, Upshur Rural Electric Cooperative, and Wood County Electric Cooperative. NTEC was founded in 1972 to make joint power supply arrangements for its member cooperatives.

The cooperative's projected 1987 peak demand was approximately 362 MW and is projected to increase at a rate of 3 percent annually, reaching 485 MW by 1997. Peak demand is met through part ownership in the H. W. Pirkey and Dolet Hills lignite plants. In addition to this 114 MW of installed capacity, NTEC makes purchases of hydro peaking power from Southwestern Power Administration. The majority of NTEC's power, however, is purchased from Southwestern Electric Power Company.

Total sales for 1987 amounted to 1,656,124 MWH. Annual sales are expected to total 2,317,544 MWH by 1997, demonstrating an average increase of 3.4 percent per year from 1987 through 1997. All sales are considered to be wholesale sales.

NTEC did not begin generating electricity until 1985. By 1987 net generation totaled 553,914 MWH. Generation is projected to increase at an average rate of 1.6 percent annually, reaching 647,092 MWH in 1997.

The City of Denton Municipal Utility (DMU), a generation and distribution utility, provides service to residential and commercial customers in the City of Denton. In 1987, DMU reported a peak demand and installed capacity of 169 MW. While installed capacity is expected to remain constant, peak demand is projected to increase to 242 MW by 1997.

DMU reported total sales of 687,496 MWH for 1987. Growth is expected to occur at a rate of 3.7 percent per year, resulting in total projected sales of 984,754 MWH by 1997. Net generation totaled 72,046 MWH in 1987 and is projected to maintain a constant level of 97,673 MWH per year from 1988 through 1997.

Tex-La Electric Cooperative of Texas (TEXLA) is a generation and transmission cooperative headquartered in Nacogdoches, Texas. TEXLA provides power to seven member distribution cooperatives, Jasper Newton Electric Cooperative, Sam Houston Electric Cooperative, Houston County Electric Cooperative, Rusk County Electric Cooperative, Cherokee County Electric Cooperative Association, Deep East Texas Electric Cooperative, and Wood County Electric Cooperative. TEXLA was founded in 1979 to make joint power supply arrangements for its member cooperatives.

The cooperative's projected 1987 peak demand was 155 MW and is projected to increase at a rate of 3.8 percent annually, reaching approximately 225 MW by 1997. Peak demand is met by purchases from the Denison Dam Hydroelectric Project through a long-term contract with Southwestern Power Administration. Supplemental requirements are provided by TU Electric and Soutwestern Electric Power Company and economy purchases from other ERCOT utilities.

Total sales projected for 1987 amounted to 742,965 MWH. Sales are expected to total 1,055,909 MWH by 1997, demonstrating an average increase of 3.6 percent per year from 1987 through 1997. All sales are considered to be wholesale sales.

TEXLA has no installed capacity and, therefore, generates no electricity. However, TEXLA owns part of the Comanche Peak Nuclear Plant. By 1997, 283,789 MWH of electricity are expected to be generated by the 50 MW of this plant's capacity which is presently owned by TEXLA.

Lubbock Power & Light (LPL), a generation and distribution utility, provides service primarily to residential and commercial customers in the City of Lubbock. In 1987, LPL reported a peak demand of 180 MW and an installed capacity of approximately 201 MW. Peak demand is projected to increase to 222 MW by 1997. Additions in installed capacity totaling roughly 48 MW are also anticipated by LPL.

In 1987 LPL reported total sales of 721,415 MWH. Growth is expected to occur at a rate of 1.9 percent per year, resulting in total projected sales of 873,011 MWH by 1997. Net Generation totaled 595,715 MWH in 1987 and is projected to increase to 641,491 MWH by 1997. This would represent average annual growth of 0.7 percent.

The City of Bryan Municipal Utility (BRYAN), a generation and distribution utility, provides service primarily to residential and commercial customers in the City of Bryan. In 1987 Bryan reported a peak demand of 152 MW and an installed capacity of 235 MW. While installed capacity is expected to remain constant, peak demand is projected to increase to 184 MW by 1997.

The City of Bryan reported total sales of 687,496 MWH in 1987. Growth is expected to occur at a rate of 3.7 percent per year, resulting in total projected sales of 984,754 MWH by 1997. Net generation totaled 361,920 MWH in 1987 and is projected to increase to 422,050 MWH by 1997.

The Southwestern Power Administration (SWPA), a Federal agency of the Department of Energy, markets hydroelectric power supplied from 86 generating units installed in 23 reservoirs located in Oklahoma, Texas, Arkansas, and Missouri. SWPA does not have utility responsibility nor a specifically defined service area. The system installed capacity equals 2,043.6 MW, with planned additions in 1991 to bring the total to 2,150.4 MW. In Texas, installed capacity equals 152 MW and is reported to remain so over the forecast period.

Sales in 1987 from the Sam Rayburn Project amounted to 143,415 MWH, greater than the projected annual generation of 91,590 MWH, and the entire amount goes to the Sam Rayburn Dam Electric Cooperative served by GSU. Sales from the Whitney Project of 88,947 MWH in 1987 exceeded the forecast annual generation of 75,500 MWH, and the entire amount goes to BEPC. Sales from the Denison Project in 1987 of 506,694 MWH also exceeded the forecast annual generation of 205,700 MWH, and the entire amount goes to the Tex-La Electric Cooperative of Texas and Rayburn Country Electric Cooperative served by TU Electric.

The Guadalupe-Blanco River Authority (GBRA) operates six hydroelectric generating units in Guadalupe County, Texas, with a total installed capacity of 16.8 MW. A seventh unit, at Canyon dam in Comal County, Texas, is under construction and expected to begin generating in November, 1988. Net generation in 1987 of 103,993 MWH was exceeded only once, in 1979, since 1977. After the addition of the Canyon unit, forecast sales equal 87,060 MWH annually through 1997. This amount does not include scheduled retirements of the Abbott and Nolte generating units in 1993, the H-4 and H-5 units in 1996, and the TP-4 unit in 1997.

The City of Tulia owns ten gas generating units with an installed capacity of 16 MW. Generation ceased in 1986 and Tulia now purchases all of its power from SPS, with a firm contract for 7.65 MW in 1987 growing to 9.37 MW in 1997. Purchased power amounted to 30,105 MWH in 1987 and is projected at 36,698 MWH in 1997.

The Brazos River Authority operates two hydroelectric generating units installed at Possum Kingdom Lake in Palo Pinto County, Texas, with a total installed capacity of 22.5 MW. The entire output, 54,704 MWH in 1987, is sold to BEPC. Power is generated on call from BEPC dispatch rather than at Brazos River Authority discretion. Annual net generation is not forecast, but over the period from 1977 to 1987, average annual generation amounted to 36,377 MWH.

The Sabine River Authority owns two hydroelectric units with installed capacity of 40.4 MW. The units are operated by GSU. Net generation in 1987 equaled 144,890 MWH with a forecast annual generation of 106,223 MWH. The Sabine River Authority is studying the possibility of adding another 40-MW generating unit at the same Toledo Bend site.

Brownsville Municipal Public Utilities Board (BMPUB) recorded sales of 556,681 MWH in 1987. The largest sectoral sales occurred in the industrial, with 275,930 MWH, 50 percent of the total. Residential sales amounted to 212,723, or 38 percent in 1987. Total system sales projections show an average compound annual increase of 2.2 percent through 1997, reaching 687,371 MWH. Peak demand registered 131 MW in 1987 with a forecast increase to 157 MW in 1997. No adjustments to demand are shown in the past or future.

BMPUB owns four Silas Ray units in Cameron County, Texas, with aggregate installed capacity of 96 MW, and 68 MW in the Oklaunion coal plant in Wilbarger County, Texas. Net generation in 1987 amounted to 395,161 MWH with 83 percent from the coal generating station and 17 percent from the gas facilities. BMPUB also purchased 223,027

MWH in 1987 with 35 MW in firm capacity, 28 MW from CP&L and 7 MW from the Falcon & Amistad Hydro Project.

Other utilities filing with the PUC include:

Brownfield Municipal and Light sold 57,453 MWH in 1987 at a peak demand of 16 MW. The city owns seven gas generating units, six diesels, and one turbine, with a total installed capacity of 22 MW. Net generation in 1987, and the annual forecast, shows 3,581 MWH from gas and 221 MWH from oil. Brownfield purchased 60,512 MWH in 1987, and purchased power is projected to increase to 62,455 MWH in 1997.

The City of Hearne sold 33,733 MWH in 1987 at a peak demand of nearly 10 MW. Hearne owns five gas generating units with a total installed capacity of 7.8 MW. Hearne has not generated any electricity since 1985 and projects none for the future. A firm contract with BEPC for 10.26 MW supplies the city's needs.

APPENDIX A
DEMAND-SIDE MANAGEMENT DATABASE FOR TEXAS

APPENDIX A

DSM DATABASE FOR TEXAS: A DATABASE OF DEMAND-SIDE MANAGEMENT PROGRAMS WITH MEASURABLE IMPACTS

The energy efficiency plans filed by major electric generating utilities with the Public Utility Commission of Texas contain descriptions and data for dozens of end-user energy efficiency programs. These data are summarized in a Commission staff database of demand-side management programs. A portion of these data are presented in the tables which follow.

Each program, or portion thereof, is one database record. One reported "program" may be entered in the database as two "program elements" to distinguish among two or more classes of customers, technologies, load shape impacts, or sets of costs. Substantive Rule 23.22 requires utilities to report cost-benefit data for each full-scale or proposed demand-side program. In addition to these quantitative data, each program is qualitatively classified by several attributes. Both the utilities' energy efficiency plans and this database have adopted the demand-side management terminology used by of the Electric Power Research Institute (EPRI). The following descriptions of data fields are ordered to correspond to the tables. Missing numeric data are represented by a blank and missing qualitative data by an "x".

Table 1: Program classification

Program name (PROGNAME). The name supplied by the utility is truncated if it is more than 50 characters. Additional descriptive information is added to the name if a program has been divided into program elements.

Program code (CODE). Each program element has a unique identification code. Three characters identify the utility. Numbers assigned in the order in which programs are reported in the energy efficiency plans occupy the fifth and sixth characters. For example, "LCR-01.0" is the Lower Colorado River Authority's first program. The decimal number indicates whether a program is divided into program elements. Program elements use decimal suffixes (.1, ..., *etc.*) to distinguish them from data representing an entire program (.0). Several program elements may be made if, for example, two technologies or

customer classes are affected by a program. This division is a logical first step to further analysis because each technology may have a different load shape impact on each class of customers.

Target customer class (CLASS). The customer class of each program is stated. Customer classes include residential, commercial, industrial, agricultural, municipal, and wholesale. "Wholesale" refers to activities, such as wholesale rates, which do not directly affect retail end uses. Two or more categories are allowed; however, every attempt is made to divide multi-class programs into two or more program elements as described above.

CLASS:

RES	residential
COM	commercial
IND	industrial
AGR	agricultural
MUN	municipal
WHL	wholesale

Target customer subclass (SUBCLASS). The market for demand programs includes existing customers and new (growth) customers. Where both are eligible, an attempt is made to divide the program into program elements.

SUBCLASS:

EXIST	existing customers
NEW	new or growth customers
BOTH	both existing and new customers are eligible for a program

End use (ENDUSE). The end-use categories used by EPRI in its REEPS and COMMEND end-use models are employed here. "Miscellaneous" refers to end uses not included in the stated classifiers. (For example, residential dish washing is included in miscellaneous.) Freezers are defined as a refrigerator end use. The term "all" refers to programs which target several or all end uses. (For example, audit and survey programs look at whole buildings, systems, or process; special rates affect all end uses.)

ENDUSE:

(Residential and commercial)	
HEAT	space heating
WATER	water heating
COOL	air conditioning
REFG	refrigeration
COOK	cooking
LITE	lighting
MISC	miscellaneous
ALL	many or all end uses

(Industrial, agricultural, and municipal)

DRIVE[1]	motors for drive power
PRHEAT	process heat applications
PUMP	water pumping
IRRG	irrigation improvements (non-pumping)
LITE	lighting
ELECTECH	electro-technologies
MISC	miscellaneous
ALL	many or all end uses

Load shape objective (LSOBJ). Load shape objectives were formalized by EPRI in 1982 as follows: strategic conservation, strategic load growth, peak clipping, load shifting, valley filling, and flexible load shape. Flexible load shape is related to system reliability. Interruptible rates are typically classified as flexible load shape activities.

LSOBJ:

CLIP	peak clipping
FILL	valley filling
SHIFT	load shifting
CON	strategic conservation
GROW	strategic load growth
FLEX	flexible load shape

Program type (TYPE). Demand-side programs are utility-sponsored efforts to change the size and shape of a customer's load curve. Traditionally, program types can be classified as either conservation programs, load management programs, or interruptible rates.[2] These generic categories have been retained.

Conservation programs reduce energy use or energy use and peak demand. "Rate" includes interruptible rates and other special rates. Load management includes all other demand-side programs.

Residential heat pump programs may be classified as load management because peak is reduced and off-peak energy use is increased; all-electric new home programs, in contrast, may be classified as conservation because thermal shell improvements reduce energy use throughout the year. These preliminary classifications are a starting point for further study.

TYPE:

CON	conservation programs
LM	load management programs
RATE	special rates

Load management type (LMTYPE). Each program is classified as to whether it is actively controlled by the utility, or whether the utility assumes a passive role in its management

once the program has accomplished its purpose. Typically, interruptible loads and cycling programs are "active."

LMTYPE:

ACTIVE	fully controlled by the utility
PASSIVE	not controlled by the utility

Implementation scale (SCALE). A distinction is made among: 1) existing, full-scale programs, 2) pilot and test programs, and 3) proposed programs. Pilot and test programs are small-scale and of limited duration. Experimental rates would be classified as pilot. Proposed programs include rates which have not been approved and other programs which are planned to begin one or more years in the future.

SCALE:

FULL	full-scale implementation
PILOT	pilot, test, and demonstration programs
PROP	proposed programs

Program initiation date (INITDATE). The date on which a program began or will begin is stated. The historic equivalents of current programs are used to indicate past initiation dates.

Table 2: Technologies and implementation

Update month/year (DATADATE). The update month is the date of the document from which these data are obtained.

Service life (LIFE). Service life is the period of time the program will affect the system. Typically the life of the equipment is reported.

Primary, secondary, and tertiary technology (TECH1, TECH2, TECH3). Primary technologies are the technological focus of the program. Secondary and tertiary technologies are reported for programs which have a multi-technology emphasis. Considerable overlap may be found in the building efficiency and cooling equipment technology programs. The categories of technologies are programmatic and broad. Each includes numerous implementation-level "measures" noted in studies of technical potential.[3] Program technology abbreviations include:

TECH1:

BLDGERS	buildings/energy rating system; all building envelope efficiency options for both new and existing buildings which insure high thermal performance through the use of a comprehensive energy rating system; includes materials and techniques to reduce conduction, convection, and radiation losses/gains; includes ceiling and wall insulation, tighter construction practices to reduce infiltration, double- and triple-pane windows, window films, insulated or storm doors, and radiant barriers;
BLDG2	same as above except using a list of prescriptive measures rather than a comprehensive energy rating system;
BLDGSOL	all solar options for space heating and cooling and daylighting; includes building orientation, atriums, greenhouses;
RESIST	standard electric resistance space heating applications;
HP	air-to-air heat pump space heating and cooling applications;
HPEARTH	earth-coupled heat pumps;
HPROOM	room or through-the-wall heat pump applications;
STORHEAT	all space heating options which make use of an integrated storage medium and a form of electric heating;
DUALFUEL	dual-fuel options include the direct use of fossil fuels and electric resistance heat sized to allow full, independent space heating capabilities;
RCVHEAT	waste heat recovery from computer installations or other processes;
STORCOOL	all space cooling storage options including water, ice, and phase-change materials;
AC	central air conditioning for residential and chillers for commercial applications;
ACROOM	room air conditioning for residential and small commercial applications;
EVAP	all evaporative and two-stage cooling technologies which functioning without compressors;
WH	conventional electric water heater technology;
WHWRAP	all water heaters improvements including simple insulating blankets (wraps), pipe wraps, heat traps, and flow-back mechanisms;
WHHP	heat pump water heating with electric resistance backup;
WHSOLAR	solar-assisted water heating with electric resistance backup;
WHRCV	waste heat recovery water heating (using waste heat from air conditioners or other processes) with electric resistance backup;
WHASST	any two or all three of the previous technologies: heat pump, solar, and heat recovery water heaters;
WHSTOR	storage water heating (greater than normal capacity; frequently associated with load control);
REFG	all refrigerator and freezer efficiency options including shell, gasket, fan, and compressor improvements;
FLUO	high efficiency fluorescent luminaries, tubes, and ballasts;
HID	high intensity discharge lighting technologies such as high pressure sodium and metal halide lights;
COOK	electric cooking equipment;
HPIND	industrial heat pumps;
MOTOR	motor efficiency including all pumps;
ASD	adjustable speed drives for motors (including pumps);

PF	power factor controllers, capacitors;
IRRG	irrigation efficiency other than pump (motor) efficiency (e.g. design improvements and storage);
LM	load management/control technologies--refers to customer- and utility-owned equipment which are defined below.

Minimum efficiency standard (EFFSTD). Programs which require a minimum standard (e.g. an air conditioning Seasonal Energy Efficiency Ratio of 10.0 or greater) include this reporting category. Where a range of standards is applicable, the lowest efficiency level is stated. "UNKN" (unknown) marks those programs which probably have a standard, but such standard was unstated.

Primary and secondary marketing implementation mechanism (IMPLEM1, IMPLEM2). Program implementation categories identified by EPRI include: advertising and promotion, customer education, direct customer contact, trade ally cooperation, direct incentives, and innovative rate design. Incentives and rates, if used, are assumed to be the primary mechanism. The second field identifies the next most important mechanism, if any.

IMPLEM1:

ADV	advertising and promotion
EDUC	customer education
CONTACT	direct customer contact
ALLY	trade ally contact
INC	direct incentives (loans, rebates)
RATE	innovative or special rate incentives

Tables 3 and 4: Program magnitude and cost

Cumulative new participants, 1997 (PART97). The forecast number of participating customers is reported. This is the sum of preceding ten data input categories.

Coincident peak demand reduction per participant (PEAKKW). The coincident demand reduction per participant at the generator is reported. This estimate is adjusted for the diversity of customer use and for system line losses. An average is applied in the cases where the peak reduction changes over time. A negative number indicates growth in peak.

Peak and off-peak kilowatt-hour savings per participant (PEAKKWH, OPEAKKWH). Program energy savings at the generator per participant are separated into the peak and off-peak period components. A negative number indicates growth in energy sales.

Base year incentive cost: participant incentives and dealer/3rd-party incentives (PARTINC, DEALINC). Participant incentive costs are the net present value of direct payments, loan discounts, or rate incentives. Dealer or third-party incentives are also reported per participant.

Utility program costs (COST88, COST89, . . .). The program costs per participant include all utility expenditures per participant for advertising, labor, equipment, and supplies. Incentive payments are not included.

Table 5: Miscellaneous costs, savings, and attributes

Base year participant equipment cost (PARTCOST). Participant equipment costs are the net present value of all incremental capital costs and operating expenses. No incentive payments are included.

Customer eligibility factors (CUSTELIG). Eligibility refers to special criteria which restrict the customers which may participate. For example, an experimental rate may be available to only 100 customers or a weatherization program may have an income restriction. This category further defines eligibility criteria beyond that which is contingent upon customer class, subclass, end use, and specified criteria (such as efficiency level). A note appears in the database.

Historic impact: participation, megawatts, megawatt-hours (HISTPART, HISTMW, HISTMWH). The cumulative number of historic participants in the program, cumulative megawatt impact to date, and greatest annual megawatt-hour impact of past program efforts are stated.

Post-implementation control of load shape impacts (POSTCTRL). The technology, and thus its load shape impacts, may be controlled by the utility, the customer, by both, or it may not allow control.

POSTCTRL:

UTIL	utility-controlled
CUST	customer-controlled
BOTH	both control a portion
NEITH	neither controls (e.g. insulation)

Program permanence (PERM). Program permanence differs from the permanence of a technology (expressed above as the service life). Program permanence refers to the enduring nature of the program's ability to conserve resources. The permanence of a program is a factor in the measurement of the degree to which a utility has contributed to the "conservation of resources."[4] "High" refers, for example, to insulation that is unlikely to degrade or otherwise reduce its impact on the system load for several decades. "Medium" refers to equipment which can be replaced, though replacement is unlikely during the service life of the technology. "Low" refers to programs such as air conditioner cycling or special rates which can be terminated at will. While programs may employ durable technologies, program effectiveness relies on ongoing utility and customer commitment. Low permanence programs may be highly beneficial for system management but may not reduce reliance on inefficient generating facilities or eliminate the need for new facility construction.

HIGH, MED, & LOW

Fuel switching (SWITCH). Programs which result in fuel switching from fossil fuels to electricity are identified. This is a preliminary determination based on the type of technology, program design, and current appliance saturation levels. A detailed analysis of each program is necessary to definitively state the impact of a program on appliance saturation levels.

HIGH, MED, LOW, & NONE

Table 6: Participation detail

New participation customers, 1988-97 (NEW88, NEW89, ...). New participants in each of the ten reported years.

[1]Includes all drive power (such as fans, materials processing, and materials handling); however, water pumping and compressors for heating and cooling (heat pump technologies) are separately classified.

[2]Interruptible rates and other special rate designs are a type of load management. Interruptible rates are separately classified in Texas because of their magnitude and special treatment in this forecast.

[3]See, for example, the technical conservation measures in Technical Potential for Electrical Energy Conservation and Peak Demand Reduction in Texas Buildings, Center for Energy Studies, University of Texas at Austin, and Public Utility Commission of Texas, February 1986.

[4]In Docket No. 6765 the Commission distinguished between HL&P's interruptible rate and conservation programs by stating "that while beneficial, the interruptible rate is a rate and not a conservation tool since it does not displace capacity on a permanent basis." (Examiner's Report, p. 26.) Further, "the intent of the Act and the Substantive Rules is the permanent and not temporary conservation of resources." (Examiner's Report, p. 27.)

TABLE 1

PROGNAME	CODE	CLASS	SUBCLASS	ENDUSE	LSOBJ	TYPE	LMTYPE	SCALE	INITDATE
Good Cents Residential	CPL-01.0	RES	NEW	COOL	CON	CON	PASS	FULL	Apr-83
Centsable Home Residential	CPL-02.0	RES	EXIST	COOL	CON	CON	PASS	FULL	Sep-86
Heat Pump Incentive Residential (with Good Cents)	CPL-03.1	RES	NEW	COOL	FILL	LM	PASS	PILOT	Sep-86
Heat Pump Incentive Residential (with Centsable)	CPL-03.2	RES	EXIST	COOL	FILL	LM	PASS	PILOT	Sep-86
Heat Pump Incentive Resid. (Typical SF/Multi-)	CPL-03.3	RES	BOTH	COOL	FILL	LM	PASS	PILOT	Sep-86
Residential Conservation Service Program	CPL-04.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Jan-83
Lighting Design Assistance Program	CPL-05.0	COM	BOTH	LITE	CON	CON	PASS	FULL	Jan-87
Commercial HVAC Design Assistance Program	CPL-06.0	COM	BOTH	COOL	CON	CON	PASS	FULL	Jan-87
Irrigation/Munic. Water Pumping Plant Effic. Test	CPL-07.0	AGR/MUN	EXIST	PUMP	CON	CON	PASS	FULL	Sep-86
Better Thermal Utilization -- Industrial (BTU)	CPL-08.0	IND/COM/A	EXIST	PRHEAT	GROWTH	LM	PASS	FULL	Jan-00
Good Cents Commercial	CPL-09.0	COM	BOTH	COOL	CON	CON	PASS	PROP	Jan-90
Interruptible Load	CPL-10.0	IND	EXIST	ALL	FLEX	RATE	ACTIVE	FULL	Jan-78
Residential Conservation Service	EPE-01.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Jan-83
Walk-Through Audits	EPE-02.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Jan-85
Commercial Cool Storage	EPE-03.0	COM	BOTH	COOL	SHIFT	LM	PASS	FULL	Jan-87
Comfort Conditioning Rebates (Existing)	GSU-01.1	RES	EXIST	COOL	FILL	LM	PASS	FULL	Jan-85
Comfort Conditioning Rebates (New)	GSU-01.2	RES	NEW	COOL	FILL	LM	PASS	FULL	Jan-85
Efficient Water Heating Rebates	GSU-02.0	RES	BOTH	WATER	CON	CON	PASS	FULL	Jan-85
Good Cents New Home (AC)	GSU-03.1	RES	NEW	COOL	CON	CON	PASS	FULL	Jan-85
Good Cents New Home (HP)	GSU-03.2	RES	NEW	COOL	FILL	LM	PASS	FULL	Jan-85
Interruptible Load -- Texas	GSU-04.0	IND	EXIST	ALL	FLEX	RATE	ACTIVE	FULL	Jan-82
Electric Dryer (Single Family)	HLP-01.1	RES	BOTH	DRYER	GROWTH	LM	PASS	PROP	Jan-89
Electric Dryer (Multi-Family)	HLP-01.2	RES	BOTH	DRYER	GROWTH	LM	PASS	PROP	Jan-89
Freezer	HLP-02.0	RES	EXIST	REFG	GROWTH	LM	PASS	PROP	Jan-89
Good Cents New Home	HLP-03.0	RES	NEW	COOL/ALL	GROWTH	LM	PASS	FULL	Jan-88
Heat Pumps (Single Family)	HLP-04.1	RES	BOTH	COOL/HEAT	FILL	LM	PASS	FULL	Jan-88
Heat Pumps (Small Commercial)	HLP-04.3	COM	BOTH	COOL/HEAT	FILL	LM	PASS	FULL	Jan-88
Residential Security Lighting	HLP-05.0	RES	EXIST	LITE	FILL	LM	PASS	FULL	Jan-88
Residential Conservation Service	HLP-06.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Jan-82
Weatherization Assistance	HLP-07.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Jan-83
Commercial Cooking	HLP-08.0	COM	BOTH	COOK	GROWTH	LM	PASS	PROP	Jan-89
Commercial HVAC (Electric Chillers)	HLP-09.1	COM	BOTH	COOL	GROWTH	LM	PASS	FULL	Jan-88
Commercial HVAC (Electric Heating)	HLP-09.2	COM	NEW	HEAT	FILL	LM	PASS	PROP	Jan-88
Commercial Load Retention (MGS)	HLP-10.1	COM	EXIST	ALL	GROWTH	LM	PASS	FULL	Jan-88

continued . . .

(Table 1 continued . . .)

PROGNAME	CODE	CLASS	SUBCLASS	ENDUSE	LSOBJ	TYPE	LMTYPE	SCALE	INITDATE
Commercial Load Retention (LGS)	HLP-10.2	COM/IND	EXIST	ALL	GROWTH	LM	PASS	FULL	Jan-88
Economic Development (Direct Load Effects-LGS)	HLP-11.1	IND	BOTH	ALL	GROWTH	LM	PASS	FULL	Jan-88
Economic Development (Direct Load Effects-LOS-B)	HLP-11.2	IND	BOTH	ALL	GROWTH	LM	PASS	FULL	Jan-88
Economic Development (Total Secondary Effects)	HLP-11.3	RES/COM	BOTH	ALL	GROWTH	LM	PASS	FULL	Jan-88
Electric Motor	HLP-12.0	IND	EXIST	MOTR	GROWTH	LM	PASS	PROP	Jan-89
Facade Lighting (MGS)	HLP-13.1	COM	EXIST	LITE	FILL	LM	PASS	FULL	Jan-88
Facade Lighting (LGS)	HLP-13.2	COM	EXIST	LITE	FILL	LM	PASS	FULL	Jan-88
Industrial Load Retention	HLP-14.0	IND	EXIST	ALL	GROWTH	LM	PASS	PROP	Jan-89
Interruptible Rates (Maintain Current)	HLP-15.0	IND	EXIST	ALL	FLEX	RATE	ACTIVE	FULL	Jan-67
Nightshift Lighting	HLP-16.0	COM/IND	EXIST	LITE	FILL	LM	PASS	FULL	Jan-88
Industrial Heat Pumps	HLP-17.0	IND	EXIST	PRHEAT	GROWTH	LM	PASS	PILOT	Jan-90
Residential Air Conditioning Control	HLP-18.0	RES	BOTH	COOL	CLIP	LM	ACTIVE	PILOT	Jan-89
Residential Soft Control	HLP-19.0	RES	BOTH	ALL	FLEX	LM	PASS	PILOT	Jan-91
Standby Generation (Maintain current)	HLP-20.0	COM	EXIST	ALL	FLEX	LM	PASS	FULL	Jan-84
Thermal Storage (MGS-Hotels)	HLP-21.1	COM	EXIST	COOL	SHIFT	LM	PASS	PROP	Jan-89
Thermal Storage (MGS-Retail)	HLP-21.2	COM	EXIST	COOL	SHIFT	LM	PASS	PROP	Jan-89
Thermal Storage (MGS-Banks)	HLP-21.3	COM	EXIST	COOL	SHIFT	LM	PASS	PROP	Jan-89
Thermal Storage (LGS-Hotels)	HLP-21.4	COM	EXIST	COOL	SHIFT	LM	PASS	PROP	Jan-89
Thermal Storage (LGS-Malls)	HLP-21.5	COM	EXIST	COOL	SHIFT	LM	PASS	PROP	Jan-89
Thermal Storage (LGS-Office Buildings)	HLP-21.6	COM	EXIST	COOL	SHIFT	LM	PASS	PROP	Jan-92
Air Conditioner Cycling	LCR-01.0	RES/COM	EXIST	COOL	CLIP	LM	ACTIVE	FULL	Jul-86
Water Heater Cycling (summer)	LCR-02.1	RES/COM	EXIST	WATER	CLIP	LM	ACTIVE	FULL	Jul-86
Water Heater Cycling (winter)	LCR-02.2	RES/COM	EXIST	WATER	CLIP	LM	ACTIVE	FULL	Jul-86
Cooling Efficiency Program (Phase II)	LCR-03.1	RES/COM	BOTH	COOL	CON	CON	PASS	FULL	Sep-83
Cooling Efficiency Program (Phase III & IV)	LCR-03.2	RES/COM	BOTH	COOL	CON	CON	PASS	PROP	Jan-89
Good Cents Home	LCR-04.0	RES/COM	NEW	COOL/HEAT	CON	CON	PASS	FULL	May-86
Commercial Lighting Rebate	LCR-05.0	COM/IND	EXIST	LITE	CON	CON	PASS	FULL	Dec-86
Power Saver Purchase	LCR-06.0	WHL	EXIST	ALL	CON	LM	PASS	PROP	Apr-87
Energy Efficient Home (EEH) Program -- AC	SPS-01.1	RES	NEW	COOL	CON	CON	PASS	FULL	Jan-76
Energy Efficient Home (EEH) Program -- HP	SPS-01.2	RES	NEW	COOL	FILL	CON	PASS	FULL	Jan-76
Dual-Fuel (Add-On) Heat Pump Program	SPS-02.0	RES	EXIST	COOL	FILL	LM	PASS	FULL	Jan-82
Residential Conservation Service (RCS)	SPS-03.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Jan-81
Interruptible Rate (Maintain current)	SPS-04.0	IND	EXIST	ALL	FLEX	RATE	ACTIVE	FULL	Jan-75
Wholesale Customer Load Management	SPS-05.0	WHL	X	X	CLIP	LM	ACTIVE	FULL	Jan-00

continued . . .

(Table 1 continued . . .)

PROGNAME	CODE	CLASS	SUBCLASS	ENDUSE	LSOBJ	TYPE	LMTYPE	SCALE	INITDATE
Improved Energy Efficient Home	SWP-01.0	RES	NEW	COOL	FILL	LM	PASS	FULL	Jan-76
Air Conditioner Maintenance	SWP-02.0	RES	EXIST	COOL	CON	CON	PASS	FULL	Mar-83
Residential Conservation Service Audits	SWP-03.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Jan-82
Interruptible Load	SWP-04.0	IND	EXIST	ALL	FLEX	RATE	ACTIVE	FULL	Jan-84
Energy Checked Efficiency Home	TNP-01.0	RES	BOTH	COOL	CON	CON	PASS	FULL	Jan-75
Interruptible Irrigation Service (Maint. Current)	TNP-02.0	AGR	EXIST	PUMP	SHIFT	RATE	ACTIVE	FULL	Jan-83
EA New Single Family ("Home"; thru 1991)	TUE-01.1	RES	NEW	COOL	CON	CON	PASS	FULL	Jan-81
EA New Single Family ("w/Heat Pump"; thru 1991)	TUE-01.2	RES	NEW	COOL	FILL	LM	PASS	FULL	Jan-81
EA New Single Family ("Plus Home"; thru 1991)	TUE-01.3	RES	NEW	COOL	CON	LM	PASS	FULL	Jan-81
EA New Single Family ("Home"; 1992-97)	TUE-01.4	RES	NEW	COOL	CON	CON	PASS	PROP	Jan-92
EA New Single Family ("w/Heat Pump"; 1992-97)	TUE-01.5	RES	NEW	COOL	CON	CON	PASS	PROP	Jan-92
EA New Single Family ("Plus Home"; 1992-97)	TUE-01.6	RES	NEW	COOL	CON	CON	PASS	PROP	Jan-92
EA New Multi-Family (w/AC; 1988-91)	TUE-02.1	RES	NEW	COOL	CON	CON	PASS	FULL	Jan-81
EA New Multi-Family (w/HP; 1988-91)	TUE-02.2	RES	NEW	COOL	FILL	LM	PASS	FULL	Jan-81
EA New Multi-Family (w/AC; 1992-97)	TUE-02.3	RES	NEW	COOL	CON	CON	PASS	PROP	Jan-92
EA New Multi-Family (w/HP; 1992-97)	TUE-02.4	RES	NEW	COOL	CON	LM	PASS	PROP	Jan-92
EA New Non-Residential	TUE-03.0	COM	NEW	COOL	FILL	LM	PASS	FULL	Jan-87
EA Existing Single Family (AC)	TUE-04.1	RES	EXIST	COOL	CON	CON	PASS	FULL	Jan-81
EA Existing Single Family (HP)	TUE-04.2	RES	EXIST	COOL	FILL	LM	PASS	FULL	Jan-81
EA Existing Multi-Family (AC)	TUE-05.1	RES	EXIST	COOL	CON	CON	PASS	FULL	Jan-81
EA Existing Multi-Family (HP)	TUE-05.2	RES	EXIST	COOL	FILL	LM	PASS	FULL	Jan-81
EA Existing Non-Residential (AC)	TUE-06.1	COM	EXIST	COOL	CON	CON	PASS	FULL	Jan-82
EA Existing Non-Residential (HP)	TUE-06.2	COM	EXIST	COOL	FILL	LM	PASS	FULL	Jan-82
EA Room Unit (Residential)	TUE-07.1	RES	EXIST	COOL	CON	CON	PASS	FULL	Jan-81
EA Room Unit (Commercial)	TUE-07.2	COM	EXIST	COOL	CON	CON	PASS	FULL	Jan-81
EA Electric Water Heater Assist (Solar)	TUE-08.1	RES/COM	BOTH	WATER	CON	CON	PASS	FULL	Jan-81
EA Electric Water Heater Assist (Heat Recovery)	TUE-08.2	RES/COM	BOTH	WATER	CON	CON	PASS	FULL	Jan-81
EA Geothermal Heat Pump (1988)	TUE-09.1	RES	BOTH	COOL	FILL	LM	PASS	PILOT	Jan-88
EA Geothermal Heat Pump (1989-91)	TUE-09.2	RES	BOTH	COOL	FILL	LM	PASS	PROP	Jan-89
EA Geothermal Heat Pump (1992-97)	TUE-09.3	RES	BOTH	COOL	FILL	LM	PASS	PROP	Jan-92
EA Thermal Storage (Large)	TUE-10.1	COM	BOTH	COOL	SHIFT	LM	PASS	FULL	Jan-82
EA Thermal Storage (Intermediate)	TUE-10.2	COM	BOTH	COOL	SHIFT	LM	PASS	FULL	Jan-82
EA Thermal Storage (Small)	TUE-10.3	COM/RES	BOTH	COOL	SHIFT	LM	PASS	PROP	Jan-89
EA Lighting	TUE-11.0	COM	BOTH	LITE	CON	CON	PASS	FULL	Jan-82

continued . . .

(Table 1 continued . . .)

PROGNAME	CODE	CLASS	SUBCLASS	ENDUSE	LSOBJ	TYPE	LMTYPE	SCALE	INITDATE
Residential Conservation Service	TUE-12.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Jan-81
EA Interruptible Load (Maintain current)	TUE-13.1	IND	EXIST	ALL	FLEX	RATE	ACTIVE	FULL	Jun-83
EA Interruptible Load (New contracts)	TUE-13.2	IND	EXIST	ALL	FLEX	RATE	ACTIVE	FULL	Jun-83
EA Operation Load Shift	TUE-14.0	COM/IND	BOTH	ALL	SHIFT	RATE	PASS	FULL	Jan-84
Heat Pump Replacement Program	TUE-15.0	RES	EXIST	HEAT	CON	CON	PASS	PROP	Jan-88
Direct Load Control Program-HVAC	TUE-16.1	ALL	EXIST	COOL	CLIP	LM	ACTIVE	PILOT	Jan-86
Direct Load Control Program-Water Heater	TUE-16.2	ALL	EXIST	WATER	CLIP	LM	ACTIVE	PROP	Jan-92
Residential Lighting Program	TUE-17.0	RES	EXIST	LITE	CON	CON	PASS	PROP	Jan-91
Non-Incentive HVAC	TUE-18.0	RES/COM	BOTH	COOL	CON	CON	PASS	FULL	Jan-81
Future Technology	TUE-19.0	X	X	X	X	X	X	PROP	Jan-00
ESP Residential Central Heat Pump	WTU-01.0	RES	BOTH	COOL	FILL	LM	PASS	FULL	Jan-83
ESP Residential Central Air Conditioning	WTU-02.0	RES	BOTH	COOL	CON	CON	PASS	FULL	Jan-83
ESP Resid. Window or Through-the-Wall Heat Pump	WTU-03.0	RES	BOTH	COOL	FILL	LM	PASS	FULL	Jan-83
ESP Residential Window Air Conditioning Units	WTU-04.0	RES	BOTH	COOL	CON	CON	PASS	FULL	Jan-83
ESP Resid. Heat-Recovery Units Inst'd on CAC & HP	WTU-05.0	RES	BOTH	WATER	CON	CON	PASS	FULL	Jan-83
ESP Residential Solar Water Heating	WTU-06.0	RES	BOTH	WATER	CON	CON	PASS	FULL	Jan-83
ESP Free-Stand'g HP Water Heater Attchd to Res WH	WTU-07.0	RES	BOTH	WATER	CON	CON	PASS	FULL	Jan-86
Residential Conservation Service Program	WTU-08.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Mar-82
Quick Energy Savings Test (QUEST)	WTU-09.0	RES	EXIST	ALL	CON	CON	PASS	FULL	Apr-85
ESP Commercial Central Heat Pumps	WTU-10.0	COM	BOTH	COOL	FILL	LM	PASS	FULL	Dec-86
ESP Commercial Central Air Conditioners	WTU-11.0	COM	BOTH	COOL	CON	CON	PASS	FULL	Dec-86
ESP Commer. Window and Through-the-Wall Heat Pumps	WTU-12.0	COM	BOTH	COOL	FILL	LM	PASS	FULL	Dec-86
ESP Commercial Window Air Conditioners	WTU-13.0	COM	BOTH	COOL	CON	CON	PASS	FULL	Dec-86
Commercial Walk-Through Energy Audit	WTU-14.0	COM	EXIST	ALL	CON	CON	PASS	FULL	Jan-83
Industrial Energy Audit	WTU-15.0	IND	EXIST	ALL	CON	CON	PASS	FULL	Jul-84
Time-of-Day Irrigation Rate	WTU-16.0	AGR	EXIST	PUMP	CLIP	RATE	ACTIVE	FULL	Jan-84

TABLE 2

PROGNAME	CODE	DATADATE	LIFE	TECH1	TECH2	TECH3	EFFSTD	IMPLEM1	IMPLEM2
Good Cents Residential	CPL-01.0	Dec-87	30	BLDGERS	-	-	-	ALLY	-
Centsable Home Residential	CPL-02.0	Dec-87	15	BLDGERS	-	-	-	CONTACT	ALLY
Heat Pump Incentive Residential (with Good Cents)	CPL-03.1	Dec-87	15	HP	-	-	8.0	INC	ALLY
Heat Pump Incentive Residential (with Centsable)	CPL-03.2	Dec-87	15	HP	-	-	8.0	INC	ALLY
Heat Pump Incentive Resid. (Typical SF/Multi-)	CPL-03.3	Dec-87	15	HP	-	-	8.0	INC	ALLY
Residential Conservation Service Program	CPL-04.0	Dec-87	15	BLDG2	-	-	-	CONTACT	-
Lighting Design Assistance Program	CPL-05.0	Dec-87	5	FLUO	HID	-	-	CONTACT	-
Commercial HVAC Design Assistance Program	CPL-06.0	Dec-87	15	AC	-	-	-	CONTACT	-
Irrigation/Munic. Water Pumping Plant Effic. Test	CPL-07.0	Dec-87	15	MOTR	IRRG	-	-	CONTACT	-
Better Thermal Utilization -- Industrial (BTU)	CPL-08.0	Dec-87	15	HPINDUS	-	-	-	CONTACT	-
Good Cents Commercial	CPL-09.0	Dec-87	15	FLUO	AC	BLDGERS	NONE	ALLY	CONTACT
Interruptible Load	CPL-10.0	Dec-87	25	LM	-	-	??	RATE	-
Residential Conservation Service	EPE-01.0	Mar-88	10	BLDG2	WHWRAP	-	-	CONTACT	-
Walk-Through Audits	EPE-02.0	Mar-88	10	BLDG2	WHWRAP	-	-	CONTACT	-
Commercial Cool Storage	EPE-03.0	Mar-88	20	STORCOOL	-	-	-	INC	CONTACT
Comfort Conditioning Rebates (Existing)	GSU-01.1	Dec-87	10	HP	-	-	8.5	INC	ALLY
Comfort Conditioning Rebates (New)	GSU-01.2	Dec-87	10	HP	-	-	8.5	INC	ALLY
Efficient Water Heating Rebates	GSU-02.0	Dec-87	10	WHHP	WHRECOV	-	-	INC	ALLY
Good Cents New Home (AC)	GSU-03.1	Dec-87	20	BLDGERS	AC	-	10.0	ALLY	RATE
Good Cents New Home (HP)	GSU-03.2	Dec-87	20	BLDGERS	HP	-	8.5	ALLY	RATE
Interruptible Load -- Texas	GSU-04.0	Dec-87	25	LM	-	-	??	RATE	-
Electric Dryer (Single Family)	HLP-01.1	Dec-87	13	DRYER	-	-	NONE	INC	ALLY
Electric Dryer (Multi-Family)	HLP-01.2	Dec-87	13	DRYER	-	-	NONE	INC	ALLY
Freezer	HLP-02.0	Dec-87	15	REFG	-	-	NONE	INC	ADV
Good Cents New Home	HLP-03.0	Aug-88	20	BLDGERS?	HP	-	10.0	INC	RATE
Heat Pumps (Single Family)	HLP-04.1	Aug-88	20	HP	-	-	9.0	INC	ALLY
Heat Pumps (Small Commercial)	HLP-04.3	Aug-88	20	HP	-	-	9.0	INC	ALLY
Residential Security Lighting	HLP-05.0	Dec-87	10	HID	-	-	HID	CONTACT	ADV
Residential Conservation Service	HLP-06.0	Dec-87	20	BLDG2	-	-	-	CONTACT	ADV
Weatherization Assistance	HLP-07.0	Dec-87	7.5	BLDG2	-	-	-	ALLY	-
Commercial Cooking	HLP-08.0	Dec-87	20	COOK	-	-	-	INC	ALLY
Commercial HVAC (Electric Chillers)	HLP-09.1	Dec-87	20	AC	-	-	NONE	CONTACT	-
Commercial HVAC (Electric Heating)	HLP-09.2	Dec-87	20	RESIST	-	-	-	CONTACT	-
Commercial Load Retention (MGS)	HLP-10.1	Dec-87	20	ALL	-	-	-	CONTACT	-

continued . . .

(Table 2 continued . . .)

PROGNAME	CODE	DATADATE	LIFE	TECH1	TECH2	TECH3	EFFSTD	IMPLEM1	IMPLEM2
Commercial Load Retention (LGS)	HLP-10.2	Dec-87	20	ALL	-	-	-	CONTACT	-
Economic Development (Direct Load Effects-LGS)	HLP-11.1	Dec-87	20	ALL	-	-	-	CONTACT	RATE
Economic Development (Direct Load Effects-LOS-B)	HLP-11.2	Dec-87	20	ALL	-	-	-	CONTACT	RATE
Economic Development (Total Secondary Effects)	HLP-11.3	Dec-87	20	ALL	-	-	-	CONTACT	-
Electric Motor	HLP-12.0	Dec-87	29.3	MOTR	-	-	-	INC	CONTACT
Facade Lighting (MGS)	HLP-13.1	Dec-87	10	HID	-	-	-	CONTACT	-
Facade Lighting (LGS)	HLP-13.2	Dec-87	10	HID	-	-	-	CONTACT	-
Industrial Load Retention	HLP-14.0	Dec-87	20	ALL	-	-	-	CONTACT	-
Interruptible Rates (Maintain Current)	HLP-15.0	Dec-87	20	LM	-	-	-	RATE	CONTACT
Nightshift Lighting	HLP-16.0	Dec-87	20	HID	-	-	-	CONTACT	-
Industrial Heat Pumps	HLP-17.0	Dec-87	20	HPINDUS	-	-	-	CONTACT	-
Residential Air Conditioning Control	HLP-18.0	Dec-87	20	LM	-	-	-	INC	-
Residential Soft Control	HLP-19.0	Dec-87	20	LM	-	-	-	RATE	INC
Standby Generation (Maintain current)	HLP-20.0	Dec-87	20	LM	-	-	-	INC	RATE
Thermal Storage (MGS-Hotels)	HLP-21.1	Dec-87	20	STORCOOL	-	-	-	INC	RATE
Thermal Storage (MGS-Retail)	HLP-21.2	Dec-87	20	STORCOOL	-	-	-	INC	RATE
Thermal Storage (MGS-Banks)	HLP-21.3	Dec-87	20	STORCOOL	-	-	-	INC	RATE
Thermal Storage (LGS-Hotels)	HLP-21.4	Dec-87	20	STORCOOL	-	-	-	INC	RATE
Thermal Storage (LGS-Malls)	HLP-21.5	Dec-87	20	STORCOOL	-	-	-	INC	RATE
Thermal Storage (LGS-Office Buildings)	HLP-21.6	Dec-87	20	STORCOOL	-	-	-	INC	RATE
Air Conditioner Cycling	LCR-01.0	Mar-88	25	LM	-	-	-	CONTACT	EDUC
Water Heater Cycling (summer)	LCR-02.1	Mar-88	25	LM	-	-	-	CONTACT	EDUC
Water Heater Cycling (winter)	LCR-02.2	Mar-88	25	LM	-	-	-	CONTACT	EDUC
Cooling Efficiency Program (Phase II)	LCR-03.1	Mar-88	15	AC	ACROOM	HP	10.0	INC	ALLY
Cooling Efficiency Program (Phase III & IV)	LCR-03.2	Mar-88	15	AC	ACROOM	HP	11.5	INC	ALLY
Good Cents Home	LCR-04.0	Mar-88	30	BLDGERS	-	-	-	ALLY	ADV
Commercial Lighting Rebate	LCR-05.0	Mar-88	6	FLUO	-	-	HIGH-EFF	INC	CONTACT
Power Saver Purchase	LCR-06.0	Mar-88	10	ALL	-	-	-	INC	CONTACT
Energy Efficient Home (EEH) Program -- AC	SPS-01.1	Dec-87	20	BLDG2	AC	-	UNKN	ALLY	-
Energy Efficient Home (EEH) Program -- HP	SPS-01.2	Dec-87	20	BLDG2	HP	-	UNKN	INC	ALLY
Dual-Fuel (Add-On) Heat Pump Program	SPS-02.0	Dec-87	20	HP	-	-	NONE	INC	ALLY
Residential Conservation Service (RCS)	SPS-03.0	Dec-87	23	BLDG2	-	-	-	CONTACT	EDUC
Interruptible Rate (Maintain current)	SPS-04.0	Dec-87	25	LM	-	-	-	RATE	-
Wholesale Customer Load Management	SPS-05.0	Dec-87	10	X	X	X	-	X	-

continued . . .

(Table 2 continued . . .)

PROGNAME	CODE	DATADATE	LIFE	TECH1	TECH2	TECH3	EFFSTD	IMPLEM1	IMPLEM2
Improved Energy Efficient Home	SWP-01.0	Dec-87	15	BLDG2	HP	WHWRAP	9.0	ALLY	CONTACT
Air Conditioner Maintenance	SWP-02.0	Dec-87	1	AC	-	-	-	ALLY	ADV
Residential Conservation Service Audits	SWP-03.0	Dec-87	10	BLDG2	AC	-	-	CONTACT	-
Interruptible Load	SWP-04.0	Dec-87	25	LM	-	-	??	RATE	-
Energy Checked Efficiency Home	TNP-01.0	Apr-88	29	BLDG2	AC	RESIST	10.0	ALLY	ADV
Interruptible Irrigation Service (Maint. Current)	TNP-02.0	Apr-88	10	LM	-	-	-	RATE	CONTACT
EA New Single Family ("Home"; thru 1991)	TUE-01.1	Dec-87	15	BLDGERS	AC	RESIST	9.0	ALLY	-
EA New Single Family ("w/Heat Pump"; thru 1991)	TUE-01.2	Dec-87	15	BLDGERS	HP	-	9.0	INC	ALLY
EA New Single Family ("Plus Home"; thru 1991)	TUE-01.3	Dec-87	15	BLDGERS	HP	WHASST	10.0	INC	ALLY
EA New Single Family ("Home"; 1992-97)	TUE-01.4	Dec-87	15	BLDGERS	AC	-	UNKN	ALLY	-
EA New Single Family ("w/Heat Pump"; 1992-97)	TUE-01.5	Dec-87	15	BLDGERS	HP	-	UNKN	ALLY	-
EA New Single Family ("Plus Home"; 1992-97)	TUE-01.6	Dec-87	15	BLDGERS	HP	WHASST	UNKN	INC	ALLY
EA New Multi-Family (w/AC; 1988-91)	TUE-02.1	Dec-87	15	BLDG2	AC	-	9.5	ALLY	-
EA New Multi-Family (w/HP; 1988-91)	TUE-02.2	Dec-87	15	BLDG2	HP	-	9.0	INC	ALLY
EA New Multi-Family (w/AC; 1992-97)	TUE-02.3	Dec-87	15	BLDG2	AC	-	UNKN	ALLY	-
EA New Multi-Family (w/HP; 1992-97)	TUE-02.4	Dec-87	15	BLDG2	HP	-	UNKN	ALLY	-
EA New Non-Residential	TUE-03.0	Dec-87	15	BLDGERS	HP	-	9.0	INC	ALLY
EA Existing Single Family (AC)	TUE-04.1	Dec-87	15	AC	-	-	9.0	INC	ALLY
EA Existing Single Family (HP)	TUE-04.2	Dec-87	15	HP	-	-	9.0	INC	ALLY
EA Existing Multi-Family (AC)	TUE-05.1	Dec-87	15	AC	-	-	9.0	INC	ALLY
EA Existing Multi-Family (HP)	TUE-05.2	Dec-87	15	HP	-	-	9.0	INC	ALLY
EA Existing Non-Residential (AC)	TUE-06.1	Dec-87	15	AC	-	-	9.0	INC	ALLY
EA Existing Non-Residential (HP)	TUE-06.2	Dec-87	15	HP	-	-	9.0	INC	ALLY
EA Room Unit (Residential)	TUE-07.1	Dec-87	10	ACROOM	HPROOM	-	9.0	INC	CONT
EA Room Unit (Commercial)	TUE-07.2	Dec-87	10	ACROOM	HPROOM	-	9.0	INC	CONT
EA Electric Water Heater Assist (Solar)	TUE-08.1	Dec-87	15	WHSOLAR	-	-	75%SUMMER	INC	CONT
EA Electric Water Heater Assist (Heat Recovery)	TUE-08.2	Dec-87	15	WHRECOV	-	-	75%SUMMER	INC	CONT
EA Geothermal Heat Pump (1988)	TUE-09.1	Dec-87	15	HPEARTH	-	-	11.0	INC	ALLY
EA Geothermal Heat Pump (1989-91)	TUE-09.2	Dec-87	15	HPEARTH	-	-	11.0	INC	ALLY
EA Geothermal Heat Pump (1992-97)	TUE-09.3	Dec-87	15	HPEARTH	-	-	11.0	INC	ALLY
EA Thermal Storage (Large)	TUE-10.1	Dec-87	20	STORCOOL	-	-	-	INC	RATE
EA Thermal Storage (Intermediate)	TUE-10.2	Dec-87	20	STORCOOL	-	-	-	INC	RATE
EA Thermal Storage (Small)	TUE-10.3	Dec-87	20	STORCOOL	-	-	-	INC	RATE
EA Lighting	TUE-11.0	Dec-87	8	FLUO	-	-	-	CONTACT	-

continued . . .

(Table 2 continued . . .)

PROGNAME	CODE	DATADATE	LIFE	TECH1	TECH2	TECH3	EFFSTD	IMPLEM1	IMPLEM2
Residential Conservation Service	TUE-12.0	Dec-87	23	BLDG2	WHWRAP	-	-	CONTACT	-
EA Interruptible Load (Maintain current)	TUE-13.1	Dec-87	25	LM	-	-	-	RATE	CONTACT
EA Interruptible Load (New contracts)	TUE-13.2	Dec-87	25	LM	-	-	-	RATE	CONTACT
EA Operation Load Shift	TUE-14.0	Dec-87	25	LM	-	-	-	RATE	CONTACT
Heat Pump Replacement Program	TUE-15.0	May-88	15	HP	-	-	-	X	X
Direct Load Control Program-HVAC	TUE-16.1	May-88	25	LM	-	-	-	RATE	CONTACT
Direct Load Control Program-Water Heater	TUE-16.2	May-88	25	LM	-	-	-	RATE	CONTACT
Residential Lighting Program	TUE-17.0	May-88	5	FLUO	-	-	-	EDUC	-
Non-Incentive HVAC	TUE-18.0	May-88	15	AC	-	-	-	EDUC	-
Future Technology	TUE-19.0	May-88	X	X	X	X	X	X	X
ESP Residential Central Heat Pump	WTU-01.0	Dec-87	17	HP	BLDG2	-	9.0	INC	ALLY
ESP Residential Central Air Conditioning	WTU-02.0	Dec-87	15	AC	BLDG2	-	10.0	INC	-
ESP Resid. Window or Through-the-Wall Heat Pump	WTU-03.0	Dec-87	10	HPROOM	-	-	8.5	INC	-
ESP Residential Window Air Conditioning Units	WTU-04.0	Dec-87	10	ACROOM	-	-	9.0	INC	-
ESP Resid. Heat-Recovery Units Inst'd on CAC & HP	WTU-05.0	Dec-87	10	WHRECOV	-	-	-	INC	-
ESP Residential Solar Water Heating	WTU-06.0	Dec-87	15	WHSOLAR	-	-	-	INC	-
ESP Free-Stand'g HP Water Heater Attchd to Res WH	WTU-07.0	Dec-87	15	WHHP	-	-	-	INC	-
Residential Conservation Service Program	WTU-08.0	Dec-87	15	BLDG2	-	-	-	CONTACT	-
Quick Energy Savings Test (QUEST)	WTU-09.0	Dec-87	15	BLDG2	-	-	-	CONTACT	-
ESP Commercial Central Heat Pumps	WTU-10.0	Dec-87	17	HP	BLDG2	-	9.0	INC	ALLY
ESP Commercial Central Air Conditioners	WTU-11.0	Dec-87	15	AC	BLDG2	-	10.0	INC	-
ESP Commer. Window and Through-the-Wall Heat Pumps	WTU-12.0	Dec-87	10	HPROOM	-	-	8.5	INC	-
ESP Commercial Window Air Conditioners	WTU-13.0	Dec-87	10	ACROOM	-	-	9.0	INC	-
Commercial Walk-Through Energy Audit	WTU-14.0	Dec-87	15	ALL	-	-	-	CONTACT	INC
Industrial Energy Audit	WTU-15.0	Dec-87	10	ALL	-	-	-	CONTACT	RATE
Time-of-Day Irrigation Rate	WTU-16.0	Dec-87	25	LM	-	-	-	RATE	-

TABLE 3

PROGNAME	CODE	PART97	PEAKKW	PEAKKWH	OPEAKKWH	PARTINC	DEALINC	COST88	COST89
Good Cents Residential	CPL-01.0	18,169	2.18	824	3999	$0	$0	$300	$200
Centsable Home Residential	CPL-02.0	10,935	1.75	265	2506	$0	$0	$500	$350
Heat Pump Incentive Residential (with Good Cents)	CPL-03.1	600	0.992	212	2005	$0	$463	$147	$0
Heat Pump Incentive Residential (with Centsable)	CPL-03.2	100	0.992	212	2005	$300	$75	$147	$0
Heat Pump Incentive Resid. (Typical SF/Multi-)	CPL-03.3	800	0.992	212	2005	$188	$50	$147	$0
Residential Conservation Service Program	CPL-04.0	2,000	0.44	95	627	$0	$0	$574	$161
Lighting Design Assistance Program	CPL-05.0	250	4	1959	8350	$0	$0	$200	$200
Commercial HVAC Design Assistance Program	CPL-06.0	250	2.97	570	2430	$0	$0	$200	$200
Irrigation/Munic. Water Pumping Plant Effic. Test	CPL-07.0	500	2.94	4265	28950	$0	$0	$45	$45
Better Thermal Utilization -- Industrial (BTU)	CPL-08.0	110	-98.64	-58960	-446510	$0	$0	$12,667	$6,000
Good Cents Commercial	CPL-09.0	1,138	5.69	3393	14352	$0	$0	$200,000	$0
Interruptible Load	CPL-10.0	1	171000	0	0	$0	$0	$0	$0
Residential Conservation Service	EPE-01.0	2,100	0.112	70	133	$0	$0	$42	$42
Walk-Through Audits	EPE-02.0	2,400	0.056	35	66	$0	$0	$0	$0
Commercial Cool Storage	EPE-03.0	51	166	86418	-86418	$33,200	$0	$16,368	$16,368
Comfort Conditioning Rebates (Existing)	GSU-01.1	720	1.22	1725	4025	$240	$65	$393	$393
Comfort Conditioning Rebates (New)	GSU-01.2	1,080	0.25	1171	2732	$240	$65	$393	$393
Efficient Water Heating Rebates	GSU-02.0	120	0	922	922	$240	$65	$185	$185
Good Cents New Home (AC)	GSU-03.1	450	1.8	1584	3697	$522	$0	$900	$900
Good Cents New Home (HP)	GSU-03.2	50	1.38	2517	5874	$522	$0	$900	$900
Interruptible Load -- Texas	GSU-04.0	1	92000	0	0	$0	$0	$0	$0
Electric Dryer (Single Family)	HLP-01.1	38,757	-0.105	-874	-153	$100	$5	$0	$130
Electric Dryer (Multi-Family)	HLP-01.2	13,784	-0.105	-720	-130	$100	$5	$0	$137
Freezer	HLP-02.0	73,700	-0.145	-1024	-185	$100	$0	$0	$263
Good Cents New Home	HLP-03.0	63,380	-0.348	-1650	-2497	$1,000	$300	$3,613	$1,316
Heat Pumps (Single Family)	HLP-04.1	135,987	0	-1732	-1028	$0	$500	$353	$170
Heat Pumps (Small Commercial)	HLP-04.3	11,314	0	0	-12000	$0	$500	$567	$568
Residential Security Lighting	HLP-05.0	166,882	0	-355	-72	$0	$0	$45	$27
Residential Conservation Service	HLP-06.0	6,000	0.3	581	103	$0	$0	$83	$87
Weatherization Assistance	HLP-07.0	30,000	0	74	0	$26	$0	$78	$82
Commercial Cooking	HLP-08.0	4,248	-21	-51767	-51767	$1,050	$420	$0	$636
Commercial HVAC (Electric Chillers)	HLP-09.1	40	-420	-567000	-378000	$0	$0	$10,916	$13,054
Commercial HVAC (Electric Heating)	HLP-09.2	47	0	0	-732708	$0	$0	$0	$52,215
Commercial Load Retention (MGS)	HLP-10.1	26	-200	-268056	-1308744	$0	$0	$50,398	$33,416

continued . . .

(Table 3 continued . . .)

PROGNAME	CODE	PART97	PEAKKW	PEAKKWH	OPEAKKWH	PARTINC	DEALINC	COST88	COST89
Commercial Load Retention (LGS)	HLP-10.2	42	-500	-707370	-3453630	$0	$0	$27,199	$16,708
Economic Development (Direct Load Effects-LGS)	HLP-11.1	77	-1000	-893520	-4362480	$0	$0	$0	$0
Economic Development (Direct Load Effects-LOS-B)	HLP-11.2	47	-5000	-5956800	-2.9E+07	$0	$0	$0	$0
Economic Development (Total Secondary Effects)	HLP-11.3	31,317	-14.89	0	-55500	$0	$0	$1,262	$1,120
Electric Motor	HLP-12.0	11	-7771	-1.1E+07	-5.4E+07	$500,000	$0	$0	$209,116
Facade Lighting (MGS)	HLP-13.1	270	0	0	-12045	$0	$0	$5,138	$2,408
Facade Lighting (LGS)	HLP-13.2	54	0	0	-60225	$0	$0	$3,787	$2,550
Industrial Load Retention	HLP-14.0	6	-36667	-5.4E+07	-2.6E+08	$0	$0	$0	$0
Interruptible Rates (Maintain Current)	HLP-15.0	29	10690	84839089	-9.7E+07	$0	$0	$0	$0
Nightshift Lighting	HLP-16.0	44,500	0	0	-1187	$0	$0	$394	$332
Industrial Heat Pumps	HLP-17.0	2	-2611	-3499471	-1.7E+07	$0	$0	$82,033	$168,635
Residential Air Conditioning Control	HLP-18.0	52,400	0.8	80	-80	$167	$0	$0	$290
Residential Soft Control	HLP-19.0	46,500	1.2	120	-108	$167	$0	$0	$0
Standby Generation (Maintain current)	HLP-20.0	1	600	60000	0	$7,200	$0	$5,240	$5,240
Thermal Storage (MGS-Hotels)	HLP-21.1	16	120	50000	-57500	$40,000	$0	$0	$21,000
Thermal Storage (MGS-Retail)	HLP-21.2	26	105	37500	-43125	$30,000	$0	$0	$15,750
Thermal Storage (MGS-Banks)	HLP-21.3	16	60	37500	-43125	$30,000	$0	$0	$15,750
Thermal Storage (LGS-Hotels)	HLP-21.4	22	240	100000	-115000	$60,000	$0	$0	$42,000
Thermal Storage (LGS-Malls)	HLP-21.5	41	280	100000	-115000	$60,000	$0	$0	$42,000
Thermal Storage (LGS-Office Buildings)	HLP-21.6	37	200	125000	-143750	$75,000	$0	$0	$0
Air Conditioner Cycling	LCR-01.0	87,900	1.12	0	0	$0	$0	$161	$129
Water Heater Cycling (summer)	LCR-02.1	58,500	0.5	0	0	$0	$0	$161	$129
Water Heater Cycling (winter)	LCR-02.2	58,500	1.2	0	0	$0	$0	$161	$129
Cooling Efficiency Program (Phase II)	LCR-03.1	8,200	0.39	506	40	$150	$102	$27	$0
Cooling Efficiency Program (Phase III & IV)	LCR-03.2	106,700	0.5586	724	57	$150	$102	$0	$11
Good Cents Home	LCR-04.0	9,900	1.55	2004	158	$0	$0	$7,382	$2,092
Commercial Lighting Rebate	LCR-05.0	523	8.34	20850	4404	$1,043	$167	$1,802	$1,591
Power Saver Purchase	LCR-06.0	1	0	0	0	$150	$0	$0	$0
Energy Efficient Home (EEH) Program -- AC	SPS-01.1	3,942	1.4	1565	3569	$0	$0	$212	$218
Energy Efficient Home (EEH) Program -- HP	SPS-01.2	0	1.4	1565	3569	$0	$496	$212	$218
Dual-Fuel (Add-On) Heat Pump Program	SPS-02.0	4,364	1.55	1464	-5768	$200	$300	$212	$218
Residential Conservation Service (RCS)	SPS-03.0	695	0.174	114	217	$0	$0	$245	$253
Interruptible Rate (Maintain current)	SPS-04.0	1	17000	0	0	$0	$0	$0	$0
Wholesale Customer Load Management	SPS-05.0	1	14000	0	0	$0	$0	$0	$0

continued . . .

(Table 3 continued . . .)

PROGNAME	CODE	PART97	PEAKKW	PEAKKWH	OPEAKKWH	PARTINC	DEALINC	COST88	COST89
Improved Energy Efficient Home	SWP-01.0	5,608	1.17	449	1064	$0	$0	$755	$676
Air Conditioner Maintenance	SWP-02.0	540,000	0.28	108	1021	$0	$0	$0	$0
Residential Conservation Service Audits	SWP-03.0	605	0	0	0	$0	$0	$76	$127
Interruptible Load	SWP-04.0	1	90000	0	0	$0	$0	$0	$0
Energy Checked Efficiency Home	TNP-01.0	4,571	1.03	2190	2530	$0	$0	$36	$37
Interruptible Irrigation Service (Maint. Current)	TNP-02.0	28	91.7	17888	-17888	$0	$0	$182	$191
EA New Single Family ("Home"; thru 1991)	TUE-01.1	57,510	0.845	346	1556	$0	$10	$39	$40
EA New Single Family ("w/Heat Pump"; thru 1991)	TUE-01.2	26,544	0.8	325	1805	$0	$235	$39	$40
EA New Single Family ("Plus Home"; thru 1991)	TUE-01.3	4,423	1.839	898	4933	$0	$485	$39	$40
EA New Single Family ("Home"; 1992-97)	TUE-01.4	114,321	0.334	127	1109	$0	$0	$0	$0
EA New Single Family ("w/Heat Pump"; 1992-97)	TUE-01.5	52,762	0.468	185	1362	$0	$0	$0	$0
EA New Single Family ("Plus Home"; 1992-97)	TUE-01.6	8,794	1.286	659	4044	$0	$50	$0	$0
EA New Multi-Family (w/AC; 1988-91)	TUE-02.1	37,029	0.377	165	1087	$0	$0	$16	$17
EA New Multi-Family (w/HP; 1988-91)	TUE-02.2	1,543	0.375	164	934	$0	$35	$16	$17
EA New Multi-Family (w/AC; 1992-97)	TUE-02.3	66,249	0.104	36	751	$0	$0	$0	$0
EA New Multi-Family (w/HP; 1992-97)	TUE-02.4	2,761	0.104	36	353	$0	$0	$0	$0
EA New Non-Residential	TUE-03.0	1,000	1.007	386	2207	$0	$300	$44	$45
EA Existing Single Family (AC)	TUE-04.1	50,408	1.057	451	920	$20	$50	$46	$47
EA Existing Single Family (HP)	TUE-04.2	5,602	0.951	407	1976	$20	$100	$46	$47
EA Existing Multi-Family (AC)	TUE-05.1	3,881	0.487	229	602	$20	$50	$21	$22
EA Existing Multi-Family (HP)	TUE-05.2	79	0.319	150	680	$20	$100	$21	$22
EA Existing Non-Residential (AC)	TUE-06.1	11,463	1.327	579	1762	$20	$50	$56	$57
EA Existing Non-Residential (HP)	TUE-06.2	2,865	1.064	464	2349	$20	$100	$56	$57
EA Room Unit (Residential)	TUE-07.1	46,692	0.275	117	239	$20	$0	$12	$12
EA Room Unit (Commercial)	TUE-07.2	2,458	0.275	117	239	$20	$0	$12	$12
EA Electric Water Heater Assist (Solar)	TUE-08.1	2,763	0.382	348	2252	$50	$20	$17	$17
EA Electric Water Heater Assist (Heat Recovery)	TUE-08.2	781	0.406	512	278	$50	$20	$17	$17
EA Geothermal Heat Pump (1988)	TUE-09.1	50	0.896	384	2401	$125	$400	$39	$0
EA Geothermal Heat Pump (1989-91)	TUE-09.2	1,100	0.896	384	2401	$125	$400	$0	$40
EA Geothermal Heat Pump (1992-97)	TUE-09.3	3,000	0.279	128	1153	$125	$400	$0	$0
EA Thermal Storage (Large)	TUE-10.1	11	1256	590347	-590347	$274,375	$0	$9,196	$3,466
EA Thermal Storage (Intermediate)	TUE-10.2	48	502	235951	-235951	$143,500	$0	$3,675	$1,385
EA Thermal Storage (Small)	TUE-10.3	604	67	31491	-31491	$23,100	$0	-	$185
EA Lighting	TUE-11.0	13,239	16.1	8522	33254	$0	$0	$708	$721

continued . . .

(Table 3 continued . . .)

PROGNAME	CODE	PART97	PEAKKW	PEAKKWH	OPEAKKWH	PARTINC	DEALINC	COST88	COST89
Residential Conservation Service	TUE-12.0	18,000	0.174	115	288	$0	$0	$162	$165
EA Interruptible Load (Maintain current)	TUE-13.1	9	17222	0	0	$0	$0	$0	$0
EA Interruptible Load (New contracts)	TUE-13.2	30	5000	0	0	$0	$0	$0	$0
EA Operation Load Shift	TUE-14.0	1,400	107.1	51000	-51000	$0	$0	$4,707	$4,801
Heat Pump Replacement Program	TUE-15.0	2,402	0	X	X	X	X		
Direct Load Control Program-HVAC	TUE-16.1	66,583	1.07	X	X	X	X		
Direct Load Control Program-Water Heater	TUE-16.2	22,757	0.535	X	X	X	X		
Residential Lighting Program	TUE-17.0	866,384	0.025	X	X	X	X		
Non-Incentive HVAC	TUE-18.0	6,297	0.626	X	X	$0	$0		
Future Technology	TUE-19.0	294,300	1	X	X	X	X		
ESP Residential Central Heat Pump	WTU-01.0	4,470	1.125	1148	813	$500	$100	$94	$99
ESP Residential Central Air Conditioning	WTU-02.0	9,032	1.125	1015	1127	$198	$0	$32	$34
ESP Resid. Window or Through-the-Wall Heat Pump	WTU-03.0	887	0.326	355	253	$75	$0	$32	$34
ESP Residential Window Air Conditioning Units	WTU-04.0	12,147	0.385	420	298	$40	$0	$32	$34
ESP Resid. Heat-Recovery Units Inst'd on CAC & HP	WTU-05.0	311	0.5	459	2601	$100	$0	$32	$34
ESP Residential Solar Water Heating	WTU-06.0	22	0.5	321	1821	$100	$0	$32	$34
ESP Free-Stand'g HP Water Heater Attchd to Res WH	WTU-07.0	38	0.25	398	2254	$100	$0	$32	$34
Residential Conservation Service Program	WTU-08.0	700	0.7	559	335	$0	$0	$275	$275
Quick Energy Savings Test (QUEST)	WTU-09.0	7,500	0.7	559	335	$0	$0	$20	$20
ESP Commercial Central Heat Pumps	WTU-10.0	2,368	3.33	4122	2918	$1,320	$100	$94	$99
ESP Commercial Central Air Conditioners	WTU-11.0	1,341	3	3774	2626	$500	$0	$32	$34
ESP Commer. Window and Through-the-Wall Heat Pumps	WTU-12.0	1,589	0.326	406	288	$75	$0	$32	$34
ESP Commercial Window Air Conditioners	WTU-13.0	915	0.385	480	340	$40	$0	$32	$34
Commercial Walk-Through Energy Audit	WTU-14.0	515	2.63	2656	2944	$600	$0	$93	$98
Industrial Energy Audit	WTU-15.0	100	7.6	21591	259909	$0	$0	$191	$191
Time-of-Day Irrigation Rate	WTU-16.0	10	580						

TABLE 4

PROGNAME	CODE	COST90	COST91	COST92	COST93	COST94	COST95	COST96	COST97
Good Cents Residential	CPL-01.0	$200	$200	$200	$200	$200	$200	$200	$200
Centsable Home Residential	CPL-02.0	$200	$150	$150	$150	$150	$150	$150	$150
Heat Pump Incentive Residential (with Good Cents)	CPL-03.1	$0	$0	$0	$0	$0	$0	$0	$0
Heat Pump Incentive Residential (with Centsable)	CPL-03.2	$0	$0	$0	$0	$0	$0	$0	$0
Heat Pump Incentive Resid. (Typical SF/Multi-)	CPL-03.3	$0	$0	$0	$0	$0	$0	$0	$0
Residential Conservation Service Program	CPL-04.0	$0	$0	$0	$0	$0	$0	$0	$0
Lighting Design Assistance Program	CPL-05.0	$0	$0	$0	$0	$0	$0	$0	$0
Commercial HVAC Design Assistance Program	CPL-06.0	$0	$0	$0	$0	$0	$0	$0	$0
Irrigation/Munic. Water Pumping Plant Effic. Test	CPL-07.0	$45	$45	$45	$0	$0	$0	$0	$0
Better Thermal Utilization -- Industrial (BTU)	CPL-08.0	$1,333	$1,333	$1,636	$3,273	$3,273	$0	$0	$0
Good Cents Commercial	CPL-09.0	$450	$450	$450	$450	$450	$450	$450	$450
Interruptible Load	CPL-10.0	$0	$0	$0	$0	$0	$0	$0	$0
Residential Conservation Service	EPE-01.0	$0	$0	$0	$0	$0	$0	$0	$0
Walk-Through Audits	EPE-02.0	$29	$30	$32	$34	$35	$37	$40	$42
Commercial Cool Storage	EPE-03.0	$17,269	$18,219	$19,221	$20,278	$21,393	$22,570	$23,811	$25,121
Comfort Conditioning Rebates (Existing)	GSU-01.1	$0	$0	$0	$0	$0	$0	$0	$0
Comfort Conditioning Rebates (New)	GSU-01.2	$0	$0	$0	$0	$0	$0	$0	$0
Efficient Water Heating Rebates	GSU-02.0	$0	$0	$0	$0	$0	$0	$0	$0
Good Cents New Home (AC)	GSU-03.1	$0	$0	$0	$0	$0	$0	$0	$0
Good Cents New Home (HP)	GSU-03.2	$0	$0	$0	$0	$0	$0	$0	$0
Interruptible Load -- Texas	GSU-04.0	$0	$0	$0	$0	$0	$0	$0	$0
Electric Dryer (Single Family)	HLP-01.1	$185	$148	$138	$144	$132	$150	$146	$173
Electric Dryer (Multi-Family)	HLP-01.2	$141	$132	$123	$115	$107	$101	$94	$90
Freezer	HLP-02.0	$129	$85	$85	$85	$85	$85	$86	$86
Good Cents New Home	HLP-03.0	$571	$246	$162	$114	$95	$77	$74	$63
Heat Pumps (Single Family)	HLP-04.1	$109	$72	$60	$52	$56	$57	$64	$85
Heat Pumps (Small Commercial)	HLP-04.3	$477	$262	$191	$152	$206	$111	$103	$95
Residential Security Lighting	HLP-05.0	$22	$19	$26	$57	$119	$124	$129	$135
Residential Conservation Service	HLP-06.0	$0	$0	$0	$0	$0	$0	$0	$0
Weatherization Assistance	HLP-07.0	$87	$92	$97	$102	$108	$114	$120	$126
Commercial Cooking	HLP-08.0	$350	$405	$390	$461	$436	$531	$483	$495
Commercial HVAC (Electric Chillers)	HLP-09.1	$13,772	$14,529	$15,328	$0	$0	$0	$0	$0
Commercial HVAC (Electric Heating)	HLP-09.2	$27,543	$23,246	$20,437	$21,562	$22,747	$23,999	$25,318	$26,711
Commercial Load Retention (MGS)	HLP-10.1	$17,627	$18,596	$39,238	$0	$0	$0	$0	$0

continued . . .

(Table 4 continued . . .)

PROGNAME	CODE	COST90	COST91	COST92	COST93	COST94	COST95	COST96	COST97
Commercial Load Retention (LGS)	HLP-10.2	$11,751	$12,398	$261,590	$0	$0	$0	$0	$0
Economic Development (Direct Load Effects-LGS)	HLP-11.1	$0	$0	$0	$0	$0	$0	$0	$0
Economic Development (Direct Load Effects-LOS-B)	HLP-11.2	$0	$0	$0	$0	$0	$0	$0	$0
Economic Development (Total Secondary Effects)	HLP-11.3	$1,012	$1,067	$1,126	$1,188	$1,253	$1,322	$1,395	$1,472
Electric Motor	HLP-12.0	$220,618	$232,752	$245,553	$518,116	$546,612	$576,676	$0	$0
Facade Lighting (MGS)	HLP-13.1	$2,540	$2,680	$2,828	$0	$0	$0	$0	$0
Facade Lighting (LGS)	HLP-13.2	$2,242	$2,365	$2,495	$0	$0	$0	$0	$0
Industrial Load Retention	HLP-14.0	$0	$0	$0	$0	$0	$0	$0	$0
Interruptible Rates (Maintain Current)	HLP-15.0	$0	$0	$0	$0	$0	$0	$0	$0
Nightshift Lighting	HLP-16.0	$310	$369	$419	$443	$467	$493	$520	$548
Industrial Heat Pumps	HLP-17.0	$125,160	$132,044	$139,306	$0	$0	$0	$0	$0
Residential Air Conditioning Control	HLP-18.0	$326	$416	$333	$403	$402	$492	$582	$672
Residential Soft Control	HLP-19.0	$0	$350	$360	$356	$363	$383	$403	$423
Standby Generation (Maintain current)	HLP-20.0	$5,240	$5,240	$5,240	$5,240	$5,240	$5,240	$5,240	$5,240
Thermal Storage (MGS-Hotels)	HLP-21.1	$21,000	$21,000	$21,000	$21,000	$21,000	$21,000	$21,000	$21,000
Thermal Storage (MGS-Retail)	HLP-21.2	$15,750	$15,750	$15,750	$15,750	$15,750	$15,750	$15,750	$15,750
Thermal Storage (MGS-Banks)	HLP-21.3	$15,750	$15,750	$15,750	$15,750	$15,750	$15,750	$15,750	$15,750
Thermal Storage (LGS-Hotels)	HLP-21.4	$42,000	$42,000	$42,000	$42,000	$42,000	$42,000	$42,000	$42,000
Thermal Storage (LGS-Malls)	HLP-21.5	$42,000	$42,000	$42,000	$42,000	$42,000	$42,000	$42,000	$42,000
Thermal Storage (LGS-Office Buildings)	HLP-21.6	$0	$0	$52,500	$52,500	$52,500	$52,500	$52,500	$52,500
Air Conditioner Cycling	LCR-01.0	$127	$125	$124	$122	$120	$118	$117	$115
Water Heater Cycling (summer)	LCR-02.1	$127	$125	$124	$122	$120	$118	$117	$115
Water Heater Cycling (winter)	LCR-02.2	$127	$125	$124	$122	$120	$118	$117	$115
Cooling Efficiency Program (Phase II)	LCR-03.1	$0	$0	$0	$0	$0	$0	$0	$0
Cooling Efficiency Program (Phase III & IV)	LCR-03.2	$55	$20	$16	$64	$24	$16	$63	$23
Good Cents Home	LCR-04.0	$622	$405	$276	$256	$203	$188	$160	$149
Commercial Lighting Rebate	LCR-05.0	$1,243	$1,123	$1,025	$1,025	$1,025	$1,025	$1,025	$1,025
Power Saver Purchase	LCR-06.0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Efficient Home (EEH) Program -- AC	SPS-01.1	$225	$232	$239	$246	$253	$261	$269	$277
Energy Efficient Home (EEH) Program -- HP	SPS-01.2	$225	$232	$239	$246	$253	$261	$269	$277
Dual-Fuel (Add-On) Heat Pump Program	SPS-02.0	$225	$232	$239	$246	$253	$261	$269	$277
Residential Conservation Service (RCS)	SPS-03.0	$0	$0	$0	$0	$0	$0	$0	$0
Interruptible Rate (Maintain current)	SPS-04.0	$0	$0	$0	$0	$0	$0	$0	$0
Wholesale Customer Load Management	SPS-05.0	$0	$0	$0	$0	$0	$0	$0	$0

continued . . .

(Table 4 continued . . .)

PROGNAME	CODE	COST90	COST91	COST92	COST93	COST94	COST95	COST96	COST97
Improved Energy Efficient Home	SWP-01.0	$618	$516	$490	$468	$451	$383	$376	$352
Air Conditioner Maintenance	SWP-02.0	$0	$0	$0	$0	$0	$0	$0	$0
Residential Conservation Service Audits	SWP-03.0	$0	$0	$0	$0	$0	$0	$0	$0
Interruptible Load	SWP-04.0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Checked Efficiency Home	TNP-01.0	$38	$40	$41	$43	$44	$45	$47	$48
Interruptible Irrigation Service (Maint. Current)	TNP-02.0	$201	$211	$221	$232	$244	$256	$269	$282
EA New Single Family ("Home"; thru 1991)	TUE-01.1	$40	$41	$20	$21	$21	$21	$22	$22
EA New Single Family ("w/Heat Pump"; thru 1991)	TUE-01.2	$40	$41	$20	$21	$21	$21	$22	$22
EA New Single Family ("Plus Home"; thru 1991)	TUE-01.3	$40	$41	$20	$21	$21	$21	$22	$22
EA New Single Family ("Home"; 1992-97)	TUE-01.4	$0	$0	$20	$21	$21	$21	$22	$22
EA New Single Family ("w/Heat Pump"; 1992-97)	TUE-01.5	$0	$0	$20	$21	$21	$21	$22	$22
EA New Single Family ("Plus Home"; 1992-97)	TUE-01.6	$0	$0	$20	$21	$21	$21	$22	$22
EA New Multi-Family (w/AC; 1988-91)	TUE-02.1	$17	$17	$0	$0	$0	$0	$0	$0
EA New Multi-Family (w/HP; 1988-91)	TUE-02.2	$17	$17	$0	$0	$0	$0	$0	$0
EA New Multi-Family (w/AC; 1992-97)	TUE-02.3	$0	$0	$6	$6	$6	$6	$6	$6
EA New Multi-Family (w/HP; 1992-97)	TUE-02.4	$0	$0	$6	$6	$6	$6	$6	$6
EA New Non-Residential	TUE-03.0	$46	$47	$0	$0	$0	$0	$0	$0
EA Existing Single Family (AC)	TUE-04.1	$48	$49	$0	$0	$0	$0	$0	$0
EA Existing Single Family (HP)	TUE-04.2	$48	$49	$0	$0	$0	$0	$0	$0
EA Existing Multi-Family (AC)	TUE-05.1	$22	$23	$0	$0	$0	$0	$0	$0
EA Existing Multi-Family (HP)	TUE-05.2	$22	$23	$0	$0	$0	$0	$0	$0
EA Existing Non-Residential (AC)	TUE-06.1	$58	$59	$0	$0	$0	$0	$0	$0
EA Existing Non-Residential (HP)	TUE-06.2	$58	$59	$0	$0	$0	$0	$0	$0
EA Room Unit (Residential)	TUE-07.1	$13	$13	$0	$0	$0	$0	$0	$0
EA Room Unit (Commercial)	TUE-07.2	$13	$13	$0	$0	$0	$0	$0	$0
EA Electric Water Heater Assist (Solar)	TUE-08.1	$18	$18	$19	$19	$19	$20	$20	$20
EA Electric Water Heater Assist (Heat Recovery)	TUE-08.2	$18	$18	$19	$19	$19	$20	$20	$20
EA Geothermal Heat Pump (1988)	TUE-09.1	$0	$0	$0	$0	$0	$0	$0	$0
EA Geothermal Heat Pump (1989-91)	TUE-09.2	$41	$42	$0	$0	$0	$0	$0	$0
EA Geothermal Heat Pump (1992-97)	TUE-09.3	$0	$0	$14	$14	$14	$14	$14	$15
EA Thermal Storage (Large)	TUE-10.1	$2,728	$1,541	$1,045	$761	$606	$586	$574	$552
EA Thermal Storage (Intermediate)	TUE-10.2	$1,090	$616	$418	$304	$242	$234	$229	$220
EA Thermal Storage (Small)	TUE-10.3	$146	$82	$56	$41	$32	$31	$31	$29
EA Lighting	TUE-11.0	$736	$751	$766	$781	$797	$813	$829	$846

continued . . .

(Table 4 continued . . .)

PROGNAME	CODE	COST90	COST91	COST92	COST93	COST94	COST95	COST96	COST97
Residential Conservation Service	TUE-12.0	$0	$0	$0	$0	$0	$0	$0	$0
EA Interruptible Load (Maintain current)	TUE-13.1	$0	$0	$0	$0	$0	$0	$0	$0
EA Interruptible Load (New contracts)	TUE-13.2	$0	$0	$0	$0	$0	$0	$0	$0
EA Operation Load Shift	TUE-14.0	$4,897	$4,995	$5,095	$5,197	$5,301	$5,407	$5,515	$5,625
Heat Pump Replacement Program	TUE-15.0								
Direct Load Control Program-HVAC	TUE-16.1								
Direct Load Control Program-Water Heater	TUE-16.2								
Residential Lighting Program	TUE-17.0								
Non-Incentive HVAC	TUE-18.0								
Future Technology	TUE-19.0								
ESP Residential Central Heat Pump	WTU-01.0	$104	$109	$114	$120	$126	$132	$139	$146
ESP Residential Central Air Conditioning	WTU-02.0	$35	$37	$39	$41	$43	$45	$47	$50
ESP Resid. Window or Through-the-Wall Heat Pump	WTU-03.0	$35	$37	$39	$41	$43	$45	$47	$50
ESP Residential Window Air Conditioning Units	WTU-04.0	$35	$37	$39	$41	$43	$45	$47	$50
ESP Resid. Heat-Recovery Units Inst'd on CAC & HP	WTU-05.0	$35	$37	$39	$41	$43	$45	$47	$50
ESP Residential Solar Water Heating	WTU-06.0	$35	$37	$39	$41	$43	$45	$47	$50
ESP Free-Stand'g HP Water Heater Attchd to Res WH	WTU-07.0	$35	$37	$39	$41	$43	$45	$47	$50
Residential Conservation Service Program	WTU-08.0	$0	$0	$0	$0	$0	$0	$0	$0
Quick Energy Savings Test (QUEST)	WTU-09.0	$25	$25	$30	$30	$35	$35	$40	$40
ESP Commercial Central Heat Pumps	WTU-10.0	$104	$109	$114	$120	$126	$132	$139	$146
ESP Commercial Central Air Conditioners	WTU-11.0	$35	$37	$39	$41	$43	$45	$47	$50
ESP Commer. Window and Through-the-Wall Heat Pumps	WTU-12.0	$35	$37	$39	$41	$43	$45	$47	$50
ESP Commercial Window Air Conditioners	WTU-13.0	$35	$37	$39	$41	$43	$45	$47	$50
Commercial Walk-Through Energy Audit	WTU-14.0	$103	$108	$113	$119	$125	$131	$137	$144
Industrial Energy Audit	WTU-15.0	$191	$191	$191	$191	$191	$191	$191	$191
Time-of-Day Irrigation Rate	WTU-16.0								

TABLE 5

PROGNAME	CODE	PARTCOST	CUSTELIG	HISTPART	HISTMW	HISTMWH	POSTCTRL	PERM	SWITCH
Good Cents Residential	CPL-01.0	$1,079	NONE	1906	4.25	8563	NEITH	HIGH	MED
Centsable Home Residential	CPL-02.0	$600	NONE	78	0.154	216	NEITH	HIGH	LOW
Heat Pump Incentive Residential (with Good Cents)	CPL-03.1	$579	NONE	1305	0.7	2084	CUST	MED	MED
Heat Pump Incentive Residential (with Centsable)	CPL-03.2	$579	NONE	-	-	-	CUST	MED	MED
Heat Pump Incentive Resid. (Typical SF/Multi-)	CPL-03.3	$579	NONE	-	-	-	CUST	MED	MED
Residential Conservation Service Program	CPL-04.0	$35	NONE	1587	NA	NA	CUST	MED	NONE
Lighting Design Assistance Program	CPL-05.0	$600	NONE	85	0.337	876	CUST	MED	NONE
Commercial HVAC Design Assistance Program	CPL-06.0	$0	X	80	0.21	240	CUST	MED	NONE
Irrigation/Munic. Water Pumping Plant Effic. Test	CPL-07.0	$1,000	NONE	77	0	0	CUST	MED	NONE
Better Thermal Utilization -- Industrial (BTU)	CPL-08.0	$43,200	THERMALLO	-	-	-	CUST	MED	HIGH
Good Cents Commercial	CPL-09.0	$1,280	NONE	-	-	-	CUST	MED	LOW
Interruptible Load	CPL-10.0	$0	> ??	??	77	-	CUST	LOW	NONE
Residential Conservation Service	EPE-01.0	$154	INDIV-MTR	1,118	-	-	CUST	HIGH	NONE
Walk-Through Audits	EPE-02.0	$154	INDIV-MTR	212	-	-	CUST	HIGH	NONE
Commercial Cool Storage	EPE-03.0	$7,350	COM/IND	1	0.25	-	CUST	MED	NONE
Comfort Conditioning Rebates (Existing)	GSU-01.1	$450	CENTRALUN	1,889	1.22	11617	CUST	MED	MED
Comfort Conditioning Rebates (New)	GSU-01.2	$450	CENTRALUN	-	-	-	CUST	MED	MED
Efficient Water Heating Rebates	GSU-02.0	$750	NONE	49	0	129	CUST	MED	MED
Good Cents New Home (AC)	GSU-03.1	$1,525	SFDU,TOWN	1,015	1.53	18000	NEITH	HIGH	MED
Good Cents New Home (HP)	GSU-03.2	$1,525	SFDU,TOWN	-	-	-	NEITH	HIGH	MED
Interruptible Load -- Texas	GSU-04.0	$0	> ??	??	92	-	CUST	LOW	NONE
Electric Dryer (Single Family)	HLP-01.1	($40)	SFDU	-	-	-	CUST	MED	HIGH
Electric Dryer (Multi-Family)	HLP-01.2	$256	MULTI-	-	-	-	CUST	MED	HIGH
Freezer	HLP-02.0	$508	SFDU	-	-	-	CUST	MED	NONE
Good Cents New Home	HLP-03.0	$1,500	AE-SFDU	-	-	-	CUST	MED	HIGH
Heat Pumps (Single Family)	HLP-04.1	$1,000	MF-SFDU	-	-	-	CUST	MED	HIGH
Heat Pumps (Small Commercial)	HLP-04.3	$1,000	MF-SMALLC	-	-	-	CUST	MED	HIGH
Residential Security Lighting	HLP-05.0	$250	SF&MULTI	-	-	-	CUST	MED	NONE
Residential Conservation Service	HLP-06.0	$331	NONE	43,419	13.026	29699	CUST	MED	NONE
Weatherization Assistance	HLP-07.0	$0	INCOME-AG	7,670	0	568	CUST	MED	NONE
Commercial Cooking	HLP-08.0	$0	SIC58	-	-	-	CUST	MED	HIGH
Commercial HVAC (Electric Chillers)	HLP-09.1	$61,000	GASABSORB	-	-	-	CUST	MED	HIGH
Commercial HVAC (Electric Heating)	HLP-09.2	-625000	-	-	-	-	CUST	MED	HIGH
Commercial Load Retention (MGS)	HLP-10.1	-264000	SELFGENPO	-	-	-	CUST	MED	HIGH

continued . . .

(Table 5 continued . . .)

PROGNAME	CODE	PARTCOST	CUSTELIG	HISTPART	HISTMW	HISTMWH	POSTCTRL	PERM	SWITCH
Commercial Load Retention (LGS)	HLP-10.2	-600000	SELFGENPO	-	-	-	CUST	MED	HIGH
Economic Development (Direct Load Effects-LGS)	HLP-11.1	$0	-	-	-	-	CUST	MED	HIGH
Economic Development (Direct Load Effects-LOS-B)	HLP-11.2	$0	-	-	-	-	CUST	MED	HIGH
Economic Development (Total Secondary Effects)	HLP-11.3	$0	-	-	-	-	CUST	MED	HIGH
Electric Motor	HLP-12.0	-7.1E+06	>1k-HP;GA	-	-	-	CUST	MED	HIGH
Facade Lighting (MGS)	HLP-13.1	$7,435	-	-	-	-	CUST	MED	NONE
Facade Lighting (LGS)	HLP-13.2	$42,720	-	-	-	-	CUST	MED	NONE
Industrial Load Retention	HLP-14.0	-1.9E+07	SELFGENPO	-	-	-	CUST	MED	HIGH
Interruptible Rates (Maintain Current)	HLP-15.0	$0	> 5 MW	29	310	0	CUST	LOW	HIGH
Nightshift Lighting	HLP-16.0	$0	NONE	-	-	-	BOTH	MED	NONE
Industrial Heat Pumps	HLP-17.0	1750000	LARGEIND	-	-	-	CUST	MED	HIGH
Residential Air Conditioning Control	HLP-18.0	$0	CAC	-	-	-	UTIL	LOW	NONE
Residential Soft Control	HLP-19.0	$0	X	-	-	-	BOTH	LOW	NONE
Standby Generation (Maintain current)	HLP-20.0	$0	NONE	3	0	0	CUST	LOW	NONE
Thermal Storage (MGS-Hotels)	HLP-21.1	$70,000	CHILLER	-	-	-	CUST	MED	NONE
Thermal Storage (MGS-Retail)	HLP-21.2	$52,500	CHILLER	-	-	-	CUST	MED	NONE
Thermal Storage (MGS-Banks)	HLP-21.3	$52,500	CHILLER	-	-	-	CUST	MED	NONE
Thermal Storage (LGS-Hotels)	HLP-21.4	$140,000	CHILLER	-	-	-	CUST	MED	NONE
Thermal Storage (LGS-Malls)	HLP-21.5	$140,000	CHILLER	-	-	-	CUST	MED	NONE
Thermal Storage (LGS-Office Buildings)	HLP-21.6	$175,000	CHILLER	-	-	-	CUST	MED	NONE
Air Conditioner Cycling	LCR-01.0	$0	RES-SIZED	2,000	-	-	UTIL	LOW	NONE
Water Heater Cycling (summer)	LCR-02.1	$0	40GAL	-	-	-	UTIL	LOW	NONE
Water Heater Cycling (winter)	LCR-02.2	$0	40GAL	-	-	-	UTIL	LOW	NONE
Cooling Efficiency Program (Phase II)	LCR-03.1	$250	NO	34,000	8.6	12000	CUST	MED	LOW
Cooling Efficiency Program (Phase III & IV)	LCR-03.2	$250	NO	-	-	-	CUST	MED	LOW
Good Cents Home	LCR-04.0	$1,500	SFD&MULTI	9	0.015	-	NEITH	HIGH	LOW
Commercial Lighting Rebate	LCR-05.0	$2,250	NONE	23	0.192	625	CUST	MED	NONE
Power Saver Purchase	LCR-06.0	$0	WHL-CUST	0	-	-	X	X	X
Energy Efficient Home (EEH) Program -- AC	SPS-01.1	$2,532	1-10 UNIT	3,501	NA	NA	CUST	HIGH	NONE
Energy Efficient Home (EEH) Program -- HP	SPS-01.2	$2,532	1-10 UNIT	-	-	-	CUST	HIGH	MED
Dual-Fuel (Add-On) Heat Pump Program	SPS-02.0	$1,803	EXIST-SFD	1,666	NA	NA	CUST	MED	MED
Residential Conservation Service (RCS)	SPS-03.0	$162	1-4 UNIT	965	NA	NA	CUST	HIGH	NONE
Interruptible Rate (Maintain current)	SPS-04.0	$0	LARGEIND	-	13	-	CUST	LOW	NONE
Wholesale Customer Load Management	SPS-05.0	$0	X	-	-	-	X	LOW	X

continued . . .

(Table 5 continued . . .)

PROGNAME	CODE	PARTCOST	CUSTELIG	HISTPART	HISTMW	HISTMWH	POSTCTRL	PERM	SWITCH
Improved Energy Efficient Home	SWP-01.0	$735	SFDU/TOWN	1,355	-	-	CUST	HIGH	MED
Air Conditioner Maintenance	SWP-02.0	$40	CAC	150,000	13.5	-	CUST	LOW	NONE
Residential Conservation Service Audits	SWP-03.0	$0	INDIV-MTR	896	-	-	NEITH	HIGH	NONE
Interruptible Load	SWP-04.0	$0	> ??	??	90	-	CUST	LOW	NONE
Energy Checked Efficiency Home	TNP-01.0	$950	AE,1-4 UN	8,478	8.31	33293	NEITH	MED	LOW
Interruptible Irrigation Service (Maint. Current)	TNP-02.0	$51	NA/ROW IR	50	5	0	CUST	LOW	NONE
EA New Single Family ("Home"; thru 1991)	TUE-01.1	$150	SFDU	135,879	130.884	-	CUST	MED	NONE
EA New Single Family ("w/Heat Pump"; thru 1991)	TUE-01.2	$347	SFDU	-	-	-	CUST	MED	MED
EA New Single Family ("Plus Home"; thru 1991)	TUE-01.3	$2,709	SFDU	-	-	-	CUST	MED	MED
EA New Single Family ("Home"; 1992-97)	TUE-01.4	($130)	SFDU	-	-	-	NEITH	HIGH	NONE
EA New Single Family ("w/Heat Pump"; 1992-97)	TUE-01.5	$133	SFDU	-	-	-	NEITH	HIGH	NONE
EA New Single Family ("Plus Home"; 1992-97)	TUE-01.6	$2,642	SFDU	-	-	-	NEITH	HIGH	NONE
EA New Multi-Family (w/AC; 1988-91)	TUE-02.1	$170	MULTIF	150,095	82.09	-	CUST	MED	NONE
EA New Multi-Family (w/HP; 1988-91)	TUE-02.2	$170	MULTIF	-	-	-	CUST	MED	LOW
EA New Multi-Family (w/AC; 1992-97)	TUE-02.3	($16)	MULTIF	-	-	-	NEITH	HIGH	NONE
EA New Multi-Family (w/HP; 1992-97)	TUE-02.4	($16)	MULTIF	-	-	-	NEITH	HIGH	NONE
EA New Non-Residential	TUE-03.0	$545	SMALLCOM	1,256	1.203	-	CUST	MED	LOW
EA Existing Single Family (AC)	TUE-04.1	$623	SFDU	94,163	137.095	-	CUST	MED	NONE
EA Existing Single Family (HP)	TUE-04.2	$623	SFDU	-	-	-	CUST	MED	LOW
EA Existing Multi-Family (AC)	TUE-05.1	$312	MULTIF	8,829	6.901	-	CUST	MED	NONE
EA Existing Multi-Family (HP)	TUE-05.2	$312	MULTIF	-	-	-	CUST	MED	LOW
EA Existing Non-Residential (AC)	TUE-06.1	$740	SMALLCOM	25,722	32.427	-	CUST	MED	NONE
EA Existing Non-Residential (HP)	TUE-06.2	$740	SMALLCOM	-	-	-	CUST	MED	LOW
EA Room Unit (Residential)	TUE-07.1	$47	NONE	112,423	54.648	-	CUST	MED	NONE
EA Room Unit (Commercial)	TUE-07.2	$47	NONE	-	-	-	CUST	MED	NONE
EA Electric Water Heater Assist (Solar)	TUE-08.1	$2,249	NONE	2,363	1.249	-	CUST	MED	NONE
EA Electric Water Heater Assist (Heat Recovery)	TUE-08.2	$622	NONE	-	-	-	CUST	MED	NONE
EA Geothermal Heat Pump (1988)	TUE-09.1	$2,868	NONE	-	-	-	CUST	MED	LOW
EA Geothermal Heat Pump (1989-91)	TUE-09.2	$2,868	NONE	-	-	-	CUST	MED	LOW
EA Geothermal Heat Pump (1992-97)	TUE-09.3	$2,357	NONE	-	-	-	CUST	MED	LOW
EA Thermal Storage (Large)	TUE-10.1	$403,000	NONE	43	27.338	-	CUST	MED	NONE
EA Thermal Storage (Intermediate)	TUE-10.2	$93,000	NONE	-	-	-	CUST	MED	NONE
EA Thermal Storage (Small)	TUE-10.3	$12,400	NONE	-	-	-	CUST	MED	NONE
EA Lighting	TUE-11.0	$2,443	NONE	4,982	119.029	-	CUST	MED	NONE

continued . . .

(Table 5 continued . . .)

PROGNAME	CODE	PARTCOST	CUSTELIG	HISTPART	HISTMW	HISTMWH	POSTCTRL	PERM	SWITCH
Residential Conservation Service	TUE-12.0	$154	INDIVMETR	35,914	6.249	-	NEITH	MED	NONE
EA Interruptible Load (Maintain current)	TUE-13.1	$0	>5MW	9	155	-	CUST	LOW	NONE
EA Interruptible Load (New contracts)	TUE-13.2	$36,306	>5MW	-	-	-	CUST	LOW	NONE
EA Operation Load Shift	TUE-14.0	$0	NONE	562	93.247	-	CUST	LOW	NONE
Heat Pump Replacement Program	TUE-15.0	X	ELEC RESI	-	-	-	CUST	MED	TO BE DET
Direct Load Control Program-HVAC	TUE-16.1	X	NONE	-	-	-	UTIL	LOW	NONE
Direct Load Control Program-Water Heater	TUE-16.2	X	NONE	-	-	-	UTIL	LOW	NONE
Residential Lighting Program	TUE-17.0	X	NONE	-	-	-	CUST	LOW	NONE
Non-Incentive HVAC	TUE-18.0	X	NONE	-	-	-	CUST	MED	NONE
Future Technology	TUE-19.0	X	X	-	-	-	X	X	X
ESP Residential Central Heat Pump	WTU-01.0	$2,066	NONE	1,965	2.95	1961	CUST	MED	X
ESP Residential Central Air Conditioning	WTU-02.0	$910	NONE	3,666	5.5	7853	CUST	MED	X
ESP Resid. Window or Through-the-Wall Heat Pump	WTU-03.0	$149	NONE	530	0.23	322	CUST	MED	X
ESP Residential Window Air Conditioning Units	WTU-04.0	$84	NONE	5,444	2.8	3909	CUST	MED	X
ESP Resid. Heat-Recovery Units Inst'd on CAC & HP	WTU-05.0	$793	NONE	102	0.34	312	CUST	MED	X
ESP Residential Solar Water Heating	WTU-06.0	$5,540	NONE	62	0.2	126	CUST	MED	X
ESP Free-Stand'g HP Water Heater Attchd to Res WH	WTU-07.0	$980	NONE	0	-	-	CUST	MED	X
Residential Conservation Service Program	WTU-08.0	$1,166	NONE	856	0.6	843	CUST	MED	X
Quick Energy Savings Test (QUEST)	WTU-09.0	$1,166	NONE	2,876	2	2833	CUST	MED	X
ESP Commercial Central Heat Pumps	WTU-10.0	$1,657	NONE	140	0.46	808	CUST	MED	X
ESP Commercial Central Air Conditioners	WTU-11.0	$1,221	NONE	61	0.183	390	CUST	MED	X
ESP Commer. Window and Through-the-Wall Heat Pumps	WTU-12.0	$148	NONE	77	0.025	54.3	CUST	MED	X
ESP Commercial Window Air Conditioners	WTU-13.0	$84	NONE	47	0.018	38.5	CUST	MED	X
Commercial Walk-Through Energy Audit	WTU-14.0	$1,921	HVAC-INCE	210	0.735	1176	CUST	MED	NONE
Industrial Energy Audit	WTU-15.0	$10,401	NONE	34	0.214	-	CUST	MED	NONE
Time-of-Day Irrigation Rate	WTU-16.0		X		1.46	-	CUST	LOW	NONE

TABLE 6

PROGNAME	CODE	NEW88	NEW89	NEW90	NEW91	NEW92	NEW93	NEW94	NEW95	NEW96	NEW97
Good Cents Residential	CPL-01.0	1000	1000	1200	1905	1631	1847	2055	2278	2508	2745
Centsable Home Residential	CPL-02.0	750	750	825	907	998	1098	1208	1329	1462	1608
Heat Pump Incentive Residential (with Good Cents)	CPL-03.1	600	0	0	0	0	0	0	0	0	0
Heat Pump Incentive Residential (with Centsable)	CPL-03.2	100	0	0	0	0	0	0	0	0	0
Heat Pump Incentive Resid. (Typical SF/Multi-)	CPL-03.3	800	0	0	0	0	0	0	0	0	0
Residential Conservation Service Program	CPL-04.0	1000	1000	0	0	0	0	0	0	0	0
Lighting Design Assistance Program	CPL-05.0	125	125	0	0	0	0	0	0	0	0
Commercial HVAC Design Assistance Program	CPL-06.0	125	125	0	0	0	0	0	0	0	0
Irrigation/Munic. Water Pumping Plant Effic. Test	CPL-07.0	100	100	100	100	100	0	0	0	0	0
Better Thermal Utilization -- Industrial (BTU)	CPL-08.0	6	6	27	27	22	11	11	0	0	0
Good Cents Commercial	CPL-09.0	0	0	62	78	97	121	151	189	210	230
Interruptible Load	CPL-10.0	1	CK NO.	0	0	0	0	0	0	0	0
Residential Conservation Service	EPE-01.0	1400	700	0	0	0	0	0	0	0	0
Walk-Through Audits	EPE-02.0	0	0	300	300	300	300	300	300	300	300
Commercial Cool Storage	EPE-03.0	6	5	5	5	5	5	5	5	5	5
Comfort Conditioning Rebates (Existing)	GSU-01.1	360	360	0	0	0	0	0	0	0	0
Comfort Conditioning Rebates (New)	GSU-01.2	540	540	0	0	0	0	0	0	0	0
Efficient Water Heating Rebates	GSU-02.0	60	60	0	0	0	0	0	0	0	0
Good Cents New Home (AC)	GSU-03.1	225	225	0	0	0	0	0	0	0	0
Good Cents New Home (HP)	GSU-03.2	25	25	0	0	0	0	0	0	0	0
Interruptible Load -- Texas	GSU-04.0	1	CK NO.	0	0	0	0	0	0	0	0
Electric Dryer (Single Family)	HLP-01.1	0	2880	4052	4907	5072	4712	5016	4278	4284	3556
Electric Dryer (Multi-Family)	HLP-01.2	0	1524	1414	1444	1481	1515	1550	1586	1625	1645
Freezer	HLP-02.0	0	3446	6780	9914	9589	9298	9038	8811	8536	8288
Good Cents New Home	HLP-03.0	869	2086	2992	4610	5653	8041	8900	9528	9920	10781
Heat Pumps (Single Family)	HLP-04.1	1457	4869	8009	12497	16255	19886	19379	19883	18738	15014
Heat Pumps (Small Commercial)	HLP-04.3	153	274	344	661	958	1272	989	1940	2195	2528
Residential Security Lighting	HLP-05.0	14168	22072	28748	34862	26904	13175	6608	6704	6780	6861
Residential Conservation Service	HLP-06.0	3000	3000	0	0	0	0	0	0	0	0
Weatherization Assistance	HLP-07.0	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
Commercial Cooking	HLP-08.0	0	270	518	472	517	461	515	446	517	532
Commercial HVAC (Electric Chillers)	HLP-09.1	8	8	8	8	8	0	0	0	0	0
Commercial HVAC (Electric Heating)	HLP-09.2	0	2	4	5	6	6	6	6	6	6
Commercial Load Retention (MGS)	HLP-10.1	2	4	8	8	4	0	0	0	0	0

continued . . .

(Table 6 continued . . .)

PROGNAME	CODE	NEW88	NEW89	NEW90	NEW91	NEW92	NEW93	NEW94	NEW95	NEW96	NEW97
Commercial Load Retention (LGS)	HLP-10.2	4	8	12	12	6	0	0	0	0	0
Economic Development (Direct Load Effects-LGS)	HLP-11.1	6	7	8	8	8	8	8	8	8	8
Economic Development (Direct Load Effects-LOS-B)	HLP-11.2	3	4	5	5	5	5	5	5	5	5
Economic Development (Total Secondary Effects)	HLP-11.3	2331	2802	3273	3273	3273	3273	3273	3273	3273	3273
Electric Motor	HLP-12.0	0	2	2	2	2	1	1	1	0	0
Facade Lighting (MGS)	HLP-13.1	30	60	60	60	60	0	0	0	0	0
Facade Lighting (LGS)	HLP-13.2	8	10	12	12	12	0	0	0	0	0
Industrial Load Retention	HLP-14.0	0	6	0	0	0	0	0	0	0	0
Interruptible Rates (Maintain Current)	HLP-15.0	29	0	0	0	0	0	0	0	0	0
Nightshift Lighting	HLP-16.0	2500	5000	8000	5000	4000	4000	4000	4000	4000	4000
Industrial Heat Pumps	HLP-17.0	0	0	2	0	0	0	0	0	0	0
Residential Air Conditioning Control	HLP-18.0	0	400	1000	1000	5000	5000	10000	10000	10000	10000
Residential Soft Control	HLP-19.0	0	0	0	500	1000	5000	10000	10000	10000	10000
Standby Generation (Maintain current)	HLP-20.0	1	0	0	0	0	0	0	0	0	0
Thermal Storage (MGS-Hotels)	HLP-21.1	0	1	1	2	2	2	2	2	2	2
Thermal Storage (MGS-Retail)	HLP-21.2	0	1	1	2	2	4	4	4	4	4
Thermal Storage (MGS-Banks)	HLP-21.3	0	1	1	2	2	2	2	2	2	2
Thermal Storage (LGS-Hotels)	HLP-21.4	0	1	1	2	3	3	3	3	3	3
Thermal Storage (LGS-Malls)	HLP-21.5	0	1	1	3	6	6	6	6	6	6
Thermal Storage (LGS-Office Buildings)	HLP-21.6	0	0	0	0	1	4	6	6	10	10
Air Conditioner Cycling	LCR-01.0	4500	5800	6600	7500	8500	9300	10100	11000	11800	12800
Water Heater Cycling (summer)	LCR-02.1	3600	4400	4800	5300	5700	6100	6500	7000	7300	7800
Water Heater Cycling (winter)	LCR-02.2	3600	4400	4800	5300	5700	6100	6500	7000	7300	7800
Cooling Efficiency Program (Phase II)	LCR-03.1	8200	0	0	0	0	0	0	0	0	0
Cooling Efficiency Program (Phase III & IV)	LCR-03.2	0	15800	4200	12700	19400	4700	12800	19000	4800	13300
Good Cents Home	LCR-04.0	100	300	500	700	900	1100	1300	1500	1600	1900
Commercial Lighting Rebate	LCR-05.0	39	43	47	52	57	57	57	57	57	57
Power Saver Purchase	LCR-06.0	1	0	0	0	0	0	0	0	0	0
Energy Efficient Home (EEH) Program -- AC	SPS-01.1	287	311	335	359	382	406	430	454	477	501
Energy Efficient Home (EEH) Program -- HP	SPS-01.2	Not reported separately.									
Dual-Fuel (Add-On) Heat Pump Program	SPS-02.0	274	301	331	364	401	441	485	534	587	646
Residential Conservation Service (RCS)	SPS-03.0	348	347	0	0	0	0	0	0	0	0
Interruptible Rate (Maintain current)	SPS-04.0	1	0	0	0	0	0	0	0	0	0
Wholesale Customer Load Management	SPS-05.0	1	Not reported.								

continued . . .

(Table 6 continued . . .)

PROGNAME	CODE	NEW88	NEW89	NEW90	NEW91	NEW92	NEW93	NEW94	NEW95	NEW96	NEW97
Improved Energy Efficient Home	SWP-01.0	283	330	377	471	518	566	613	754	801	895
Air Conditioner Maintenance	SWP-02.0	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000
Residential Conservation Service Audits	SWP-03.0	378	227	0	0	0	0	0	0	0	0
Interruptible Load	SWP-04.0	1	CK NO.	0	0	0	0	0	0	0	0
Energy Checked Efficiency Home	TNP-01.0	372	389	406	424	444	464	484	506	529	553
Interruptible Irrigation Service (Maint. Current)	TNP-02.0	28	0	0	0	0	0	0	0	0	0
EA New Single Family ("Home"; thru 1991)	TUE-01.1	11923	14318	15265	16004	0	0	0	0	0	0
EA New Single Family ("W/Heat Pump"; thru 1991)	TUE-01.2	5503	6608	7046	7387	0	0	0	0	0	0
EA New Single Family ("Plus Home"; thru 1991)	TUE-01.3	917	1101	1174	1231	0	0	0	0	0	0
EA New Single Family ("Home"; 1992-97)	TUE-01.4	0	0	0	0	16788	17620	18506	19446	20447	21514
EA New Single Family ("W/Heat Pump"; 1992-97)	TUE-01.5	0	0	0	0	7748	8132	8541	8975	9437	9929
EA New Single Family ("Plus Home"; 1992-97)	TUE-01.6	0	0	0	0	1291	1355	1424	1496	1573	1655
EA New Multi-Family (W/AC; 1988-91)	TUE-02.1	7677	9218	9829	10305	0	0	0	0	0	0
EA New Multi-Family (W/HP; 1988-91)	TUE-02.2	320	384	410	429	0	0	0	0	0	0
EA New Multi-Family (W/AC; 1992-97)	TUE-02.3	0	0	0	0	9729	10212	10723	11268	11849	12468
EA New Multi-Family (W/HP; 1992-97)	TUE-02.4	0	0	0	0	405	425	447	470	494	520
EA New Non-Residential	TUE-03.0	100	200	300	400	0	0	0	0	0	0
EA Existing Single Family (AC)	TUE-04.1	12137	12434	12752	13085	0	0	0	0	0	0
EA Existing Single Family (HP)	TUE-04.2	1349	1382	1417	1454	0	0	0	0	0	0
EA Existing Multi-Family (AC)	TUE-05.1	943	960	979	999	0	0	0	0	0	0
EA Existing Multi-Family (HP)	TUE-05.2	19	20	20	20	0	0	0	0	0	0
EA Existing Non-Residential (AC)	TUE-06.1	2795	2841	2889	2938	0	0	0	0	0	0
EA Existing Non-Residential (HP)	TUE-06.2	699	710	722	734	0	0	0	0	0	0
EA Room Unit (Residential)	TUE-07.1	11363	11564	11773	11992	0	0	0	0	0	0
EA Room Unit (Commercial)	TUE-07.2	598	609	620	631	0	0	0	0	0	0
EA Electric Water Heater Assist (Solar)	TUE-08.1	249	254	258	263	272	279	285	293	301	309
EA Electric Water Heater Assist (Heat Recovery)	TUE-08.2	70	72	73	74	77	79	81	83	85	87
EA Geothermal Heat Pump (1988)	TUE-09.1	50	0	0	0	0	0	0	0	0	0
EA Geothermal Heat Pump (1989-91)	TUE-09.2	0	200	400	500	0	0	0	0	0	0
EA Geothermal Heat Pump (1992-97)	TUE-09.3	0	0	0	0	500	500	500	500	500	500
EA Thermal Storage (Large)	TUE-10.1	2	1	1	1	1	1	1	1	1	1
EA Thermal Storage (Intermediate)	TUE-10.2	4	6	4	4	4	5	5	5	5	6
EA Thermal Storage (Small)	TUE-10.3	0	10	16	33	52	74	97	102	107	113
EA Lighting	TUE-11.0	998	1268	1289	1312	1334	1358	1382	1407	1432	1459

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(Table 6 continued . . .)

PROGNAME	CODE	NEW88	NEW89	NEW90	NEW91	NEW92	NEW93	NEW94	NEW95	NEW96	NEW97
Residential Conservation Service	TUE-12.0	9000	9000	0	0	0	0	0	0	0	0
EA Interruptible Load (Maintain current)	TUE-13.1	9	0	0	0	0	0	0	0	0	0
EA Interruptible Load (New contracts)	TUE-13.2	3	3	3	3	3	3	3	3	3	3
EA Operation Load Shift	TUE-14.0	50	60	80	120	150	170	180	190	200	200
Heat Pump Replacement Program	TUE-15.0	213	218	224	230	236	242	249	256	263	271
Direct Load Control Program-HVAC	TUE-16.1	923	943	2893	4933	5050	7759	10602	10872	11155	11453
Direct Load Control Program-Water Heater	TUE-16.2	0	0	0	0	2020	3104	4241	4349	4462	4581
Residential Lighting Program	TUE-17.0	0	0	0	44084	90326	138885	142453	146202	150143	154291
Non-Incentive HVAC	TUE-18.0	1406	1561	1634	1696	0	0	0	0	0	0
Future Technology	TUE-19.0	0	0	0	24000	26000	28100	30500	57000	61800	66900
ESP Residential Central Heat Pump	WTU-01.0	545	470	400	380	390	425	435	450	475	500
ESP Residential Central Air Conditioning	WTU-02.0	950	925	860	850	870	835	900	922	945	975
ESP Resid. Window or Through-the-Wall Heat Pump	WTU-03.0	75	88	83	76	85	87	91	97	105	100
ESP Residential Window Air Conditioning Units	WTU-04.0	1207	1300	1250	1180	1210	1150	1175	1200	1225	1250
ESP Resid. Heat-Recovery Units Inst'd on CAC & HP	WTU-05.0	20	22	18	24	27	30	35	40	45	50
ESP Residential Solar Water Heating	WTU-06.0	1	2	4	3	2	3	1	3	2	1
ESP Free-Stand'g HP Water Heater Attchd to Res WH	WTU-07.0	2	1	3	2	4	1	3	5	7	10
Residential Conservation Service Program	WTU-08.0	500	200	0	0	0	0	0	0	0	0
Quick Energy Savings Test (QUEST)	WTU-09.0	750	750	750	750	750	750	750	750	750	750
ESP Commercial Central Heat Pumps	WTU-10.0	175	193	210	225	240	245	255	265	275	285
ESP Commercial Central Air Conditioners	WTU-11.0	85	93	102	112	123	135	149	164	180	198
ESP Commer. Window and Through-the-Wall Heat Pumps	WTU-12.0	100	110	121	133	146	160	176	194	214	235
ESP Commercial Window Air Conditioners	WTU-13.0	60	65	70	75	85	95	105	110	120	130
Commercial Walk-Through Energy Audit	WTU-14.0	55	55	60	45	50	40	60	55	40	55
Industrial Energy Audit	WTU-15.0	10	10	10	10	10	10	10	10	10	10
Time-of-Day Irrigation Rate	WTU-16.0	1	1	1	1	1	1	1	1	1	1

APPENDIX B

INVENTORY OF ELECTRIC GENERATING UNITS

APPENDIX B
INVENTORY OF OPERATING ELECTRIC GENERATING UNITS IN TEXAS

COAL-FIRED UNITS

There are 19 coal-fired units in Texas, with a total Net Dependable Capacity (NDC) of 9,447 MW. Fayette units 1 & 2 are co-owned by The City of Austin (COA) and the Lower Colorado River Authority (LCRA), and operated by LCRA. The Oklaunion unit 1 is co-owned by West Texas Utilities Company (WTU), Brownsville Municipal Public Utilities Board (BMPUB), Central Power & Light Company (CPL), and Public Service Company of Oklahoma (PSO). WTU operates the unit. The age is Calculated as of October 1, 1988. The average age is 7.5 years.

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	Date of Commercial Operation	Age
Coleto Creek 1	CPL	IOU	605	605	Goliad	JUN-80	8.3
Fayette 1	COA	MUNI	590	295	Fayette	JUN-79	9.3
Fayette 1	LCRA	GOV	590	295	Fayette	JUN-79	9.3
Fayette 2	COA	MUNI	565	283	Fayette	MAY-80	8.4
Fayette 2	LCRA	GOV	565	283	Fayette	MAY-80	8.4
Fayette 3	LCRA	GOV	327	327	Fayette	APR-88	0.4
Harrington 1	SPS	IOU	346	346	Potter	AUG-76	12.2
Harrington 2	SPS	IOU	360	360	Potter	JUL-78	10.3
Harrington 3	SPS	IOU	360	360	Potter	JUL-80	8.3
J.T. Deely 1	CPS	MUNI	405	405	Bexar	AUG-77	11.2
J.T. Deely 2	CPS	MUNI	405	405	Bexar	MAY-78	10.4
Oklaunion 1	WTU	IOU	665.6	364	Wilbarger	DEC-86	1.8
Oklaunion 1	BMPUB	MUNI	665.6	67.6	Wilbarger	DEC-86	1.8
Oklaunion 1	CPL	IOU	665.6	51.9	Wilbarger	DEC-86	1.8
Tolk 1	SPS	IOU	540	540	Lamb	AUG-82	6.1
Tolk 2	SPS	IOU	540	540	Lamb	JUN-85	3.3
W A Parish 5	HLP	IOU	630	630	Fort Bend	DEC-77	10.8
W A Parish 6	HLP	IOU	630	630	Fort Bend	DEC-78	9.8
W A Parish 7	HLP	IOU	540	540	Fort Bend	JUN-80	8.3
W A Parish 8	HLP	IOU	535	535	Fort Bend	DEC-82	5.8
Welsh 1	SWP	IOU	528	528	Titus	MAR-77	11.5
Welsh 2	SWP	IOU	528	528	Titus	APR-80	8.5
Welsh 3	SWP	IOU	528	528	Titus	MAR-82	6.5

LIGNITE-FIRED UNIS

There are 14 Lignite-Fired units in Texas, with a total Net Dependable Capacity (NDC) of 8,255.4 MW. Henry Pirkey unit 1 is co-owned by Southwestern Electric Service Company (SWP) and Northeast Texas Electric Cooperative, Inc. (NTEC). The average age is 8.7 years.

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	Date of Commercial Operation	Age
Big Brown 1	TU	IOU	575	575	Freestone	DEC-71	16.8
Big Brown 2	TU	IOU	575	575	Freestone	DEC-72	15.8
Gibbons Creek 1	TMPA	MUNI	?	400	Grimes	OCT-84	4.0
Henry Pirkey 1	NTEC	COOP	650	76.05	Harrison	JAN-85	3.7
Henry Pirkey 1	SWP	IOU	650	558.35	Harrison	JAN-85	3.7
Limestone 1	HLP	IOU	720	720	Limestone	DEC-85	2.8
Limestone 2	HLP	IOU	720	720	Limestone	DEC-86	1.8
Martin Lake 1	TU	IOU	750	750	Rusk	MAY-77	11.4
Martin Lake 2	TU	IOU	750	750	Rusk	MAY-78	10.4
Martin Lake 3	TU	IOU	750	750	Rusk	APR-79	9.5
Monticello 1	TU	IOU	575	575	Titus	DEC-74	13.8
Monticello 2	TU	IOU	575	575	Titus	DEC-75	12.8
Monticello 3	TU	IOU	750	750	Titus	AUG-78	10.2
San Miguel 1	SMEC	COOP	391	391	Atascosa	JAN-82	6.7
Sandow 4	TU	IOU	545	90	Milam	MAY-81	7.4

NATURAL GAS-FIRED UINTS

There are 195 Natural Gas Units operating in Texas with a total Net Dependable Capacity (NDC) of 36,234 MW. The average is 24.6 years. All of these units are solely owned and operated by the reporting utility.

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	Date of Commercial Operation	Age
Barney Davis 1	CPL	IOU	334	334	Nueces	MAY-74	14.4
Barney Davis 2	CPL	IOU	338	338	Nueces	JUL-76	12.2
Bryan Municipal 6	BRYAN	MUNI	?	51	Brazos	APR-69	19.5
Cedar Bayou 1	HLP	IOU	750	750	Chambers	DEC-70	17.8
Cedar Bayou 2	HLP	IOU	750	750	Chambers	MAR-72	16.6
Cedar Bayou 3	HLP	IOU	750	750	Chambers	DEC-74	13.8
Collin 1	TU	IOU	153	153	Collin	JUN-55	33.3
Dallas 3	TU	IOU	75	75	Dallas	MAY-54	34.4
Dallas 9	TU	IOU	70	70	Dallas	FEB-51	37.6
Decker 1	COA	MUNI	310	310	Travis	AUG-70	18.2
Decker 2	COA	MUNI	400	400	Travis	AUG-77	11.2
DeCordova 1	TU	IOU	775	775	Hood	MAY-75	13.4

Natural Gas-Fired units Continued:

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	Date of Commercial Operation	Age
Deepwater 7	HLP	IOU	159	159	Harris	JUN-55	33.3
Denton 1	DMU	MUNI	11.5	11.5	Denton	JAN-54	34.7
Denton 2	DMU	MUNI	11.5	11.5	Denton	JAN-54	34.7
Denton 3	DMU	MUNI	26	26	Denton	JAN-63	25.7
Denton 4	DMU	MUNI	59	59	Denton	JAN-66	22.7
Denton 5	DMU	MUNI	61	61	Denton	JAN-73	15.7
E S Joslin 1	CPL	IOU	257	257	Calhoun	JUN-71	17.3
Eagle Mountain 1	TU	IOU	115	115	Tarrant	JUL-54	34.2
Eagle Mountain 2	TU	IOU	175	175	Tarrant	DEC-56	31.8
Eagle Mountain 3	TU	IOU	375	375	Tarrant	JUN-71	17.3
Fort Phantom 1	WTU	IOU	158	158	Jones	JUL-74	14.3
Fort Phantom 2	WTU	IOU	204	204	Jones	JUL-77	11.2
Graham 1	TU	IOU	240	240	Young	DEC-60	27.8
Graham 2	TU	IOU	375	375	Young	JUN-69	19.3
Greens Bayou 5	HLP	IOU	361	361	Harris	JUN-73	15.3
Handley 1	TU	IOU	45	45	Tarrant	APR-48	40.4
Handley 2	TU	IOU	80	80	Tarrant	DEC-50	37.8
Handley 3	TU	IOU	400	400	Tarrant	JUL-63	25.2
Handley 4	TU	IOU	425	425	Tarrant	OCT-76	11.9
Handley 5	TU	IOU	425	425	Tarrant	OCT-77	10.9
Holly 1	COA	MUNI	97	97	Travis	JUL-60	28.3
Holly 2	COA	MUNI	97	97	Travis	DEC-64	23.8
Holly 3	COA	MUNI	165	165	Travis	AUG-66	22.2
Holly 4	COA	MUNI	181	181	Travis	MAY-74	14.4
Holly St 1	LPL	MUNI	44	44	Lubbock	JAN-65	23.7
Holly St 2	LPL	MUNI	54	54	Lubbock	JAN-78	10.7
Jones 1	SPS	IOU	243	243	Lubbock	JUL-71	17.3
Jones 2	SPS	IOU	243	243	Lubbock	JUN-74	14.3
J.L. Bates 1	CPL	IOU	73	73	Hidalgo	JUN-58	30.3
J.L. Bates 2	CPL	IOU	110	110	Hidalgo	MAY-60	28.4
Knox Lee 2	SWP	IOU	38	38	Gregg	DEC-50	37.8
Knox Lee 3	SWP	IOU	36	36	Gregg	JUN-52	36.3
Knox Lee 4	SWP	IOU	83	83	Gregg	MAR-56	32.5
Knox Lee 5	SWP	IOU	344	344	Gregg	APR-74	14.4
La Palma 6	CPL	IOU	156	156	Cameron	MAY-70	18.3
Lake Creek 1	TU	IOU	87	87	McLennan	APR-53	35.4
Lake Creek 2	TU	IOU	230	230	McLennan	JUL-59	29.2
Lake Hubbard 1	TU	IOU	375	375	Dallas	JUN-70	18.3
Lake Hubbard 2	TU	IOU	515	515	Dallas	NOV-73	14.9
Laredo 1	CPL	IOU	33	33	Webb	MAY-51	37.4
Laredo 2	CPL	IOU	32	32	Webb	MAY-55	33.4
Laredo 3	CPL	IOU	104	104	Webb	AUG-75	13.1
Leon Creek 3	CPS	MUNI	65	65	Bexar	MAY-53	35.3
Leon Creek 4	CPS	MUNI	100	100	Bexar	MAY-59	29.4
Lewis Creek 1	GSU	IOU	265	265	Montgomery	DEC-70	17.8
Lewis Creek 2	GSU	IOU	265	265	Montgomery	MAY-71	17.4
Lon C. Hill 1	CPL	IOU	70	70	Nueces	MAR-54	34.6
Lon C. Hill 2	CPL	IOU	72	72	Nueces	MAR-56	32.5

Natural Gas-Fired units Continued:

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	Date of Commercial Operation	Age
Lon C. Hill 3	CPL	IOU	161	161	Nueces	MAY-59	29.4
Lon C. Hill 4	CPL	IOU	254	254	Nueces	MAY-69	19.4
Lone Star 1	SWP	IOU	50	50	Morris	MAR-54	34.6
Mission Road 3	CPS	MUNI	100	100	Bexar	JUN-58	30.3
Morgan Creek 2	TU	IOU	22	22	Mitchell	JUL-50	38.2
Morgan Creek 3	TU	IOU	44	44	Mitchell	JUL-52	36.3
Morgan Creek 4	TU	IOU	70	70	Mitchell	JUN-54	34.3
Morgan Creek 5	TU	IOU	175	175	Mitchell	JUN-59	29.3
Morgan Creek 6	TU	IOU	500	500	Mitchell	JUL-66	22.2
Mountain Creek 2	TU	IOU	33	33	Dallas	DEC-45	42.8
Mountain Creek 3	TU	IOU	70	70	Dallas	MAY-49	39.4
Mountain Creek 6	TU	IOU	115	115	Dallas	FEB-56	32.6
Mountain Creek 7	TU	IOU	125	125	Dallas	MAR-58	30.6
Mountain Creek 8	TU	IOU	550	550	Dallas	JUL-67	21.2
Newman 1	EPE	IOU	81.9	81.9	El Paso	MAY-60	28.4
Newman 2	EPE	IOU	81	81	El Paso	JUN-63	25.3
Newman 3	EPE	IOU	103	103	El Paso	MAR-66	22.5
Nichols 1	SPS	IOU	107	107	Potter	JUL-60	28.3
Nichols 2	SPS	IOU	106	106	Potter	SEP-62	26.1
Nichols 3	SPS	IOU	244	244	Potter	AUG-68	20.1
North Lake 1	TU	IOU	175	175	Dallas	DEC-59	28.8
North Lake 2	TU	IOU	175	175	Dallas	DEC-61	26.8
North Lake 3	TU	IOU	350	350	Dallas	JUL-64	24.2
North Main 4	TU	IOU	80	80	Tarrant	MAY-52	36.4
North Texas 1	BEPC	COOP	17	17	Parker	OCT-58	30.0
North Texas 2	BEPC	COOP	17	17	Parker	OCT-58	30.0
North Texas 3	BEPC	COOP	38	38	Parker	SEP-63	25.1
Nueces Bay 5	CPL	IOU	35	35	Nueces	JUL-49	39.3
Nueces Bay 6	CPL	IOU	161	161	Nueces	MAY-65	23.4
Nueces Bay 7	CPL	IOU	340	340	Nueces	JUL-72	16.2
Oak Creek 1	WTU	IOU	83	83	Coke	APR-62	26.4
O.W. Sommers 1	CPS	MUNI	430	430	Bexar	APR-72	16.4
O.W. Sommers 2	CPS	MUNI	420	420	Bexar	JAN-74	14.7
Paint Creek 3	WTU	IOU	54	54	Haskell	MAY-59	29.4
Paint Creek 4	WTU	IOU	112	112	Haskell	JUL-71	17.2
Parkdale 1	TU	IOU	87	87	Dallas	JUN-53	35.3
Parkdale 2	TU	IOU	115	115	Dallas	MAR-55	33.5
Parkdale 3	TU	IOU	125	125	Dallas	MAR-57	31.5
Pearsall 1	MEC	COOP	22	22	Frio	MAY-61	27.4
Pearsall 2	MEC	COOP	22	22	Frio	JUL-61	27.3
Pearsall 3	MEC	COOP	22	22	Frio	SEP-61	27.1
Permian Basin 5	TU	IOU	115	115	Ward	JUN-58	30.3
Permian Basin 6	TU	IOU	540	540	Ward	DEC-73	14.8
Plant X 1	SPS	IOU	48	48	Lamb	JUN-52	36.3
Plant X 2	SPS	IOU	102	102	Lamb	AUG-53	35.2
Plant X 3	SPS	IOU	103	103	Lamb	JUN-55	33.3
Plant X 4	SPS	IOU	189	189	Lamb	JUN-64	24.3
P.H. Robinson 1	HLP	IOU	441	441	Galveston	JUN-66	22.3
P.H. Robinson 2	HLP	IOU	441	441	Galveston	APR-67	21.5
P.H. Robinson 3	HLP	IOU	562	562	Galveston	DEC-68	19.8

Natural Gas-Fired units Continued:

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	Date of Commercial Operation	Age
P.H. Robinson 4	HLP	IOU	749	749	Galveston	DEC-73	14.8
Rio Pecos 5	WTU	IOU	37	37	Crockett	DEC-59	28.8
Rio Pecos 6	WTU	IOU	98	98	Crockett	MAY-69	19.4
River Crest 1	TU	IOU	110	110	Red River	JUN-54	34.3
R.C. Dansby 1	BRYAN	MUNI	?	100	Brazos	NOV-77	10.9
R.W. Miller 1	BEPC	COOP	75	75	Palo Pinto	OCT-68	20.0
R.W. Miller 2	BEPC	COOP	116	116	Palo Pinto	MAR-72	16.5
R.W. Miller 3	BEPC	COOP	200	200	Palo Pinto	AUG-75	13.2
Sabine 1	GSU	IOU	230	230	Orange	MAR-62	26.5
Sabine 2	GSU	IOU	230	230	Orange	DEC-62	25.8
Sabine 3	GSU	IOU	430	430	Orange	DEC-66	21.8
Sabine 4	GSU	IOU	568	568	Orange	AUG-74	14.2
Sabine 5	GSU	IOU	488	488	Orange	DEC-79	8.8
Sam Rayburn 3	STEC	COOP	26	26	Victoria	AUG-65	23.2
San Angelo 2	WTU	IOU	107	107	Tom Green	JUL-66	22.2
Seaholm 5	COA	MUNI	18	18	Travis	AUG-51	37.1
Seaholm 6	COA	MUNI	18	18	Travis	JUN-51	37.3
Seaholm 7	COA	MUNI	14	14	Travis	JUN-55	33.3
Seaholm 8	COA	MUNI	14	14	Travis	SEP-55	33.0
Seaholm 9	COA	MUNI	36	36	Travis	SEP-58	30.1
Silas Ray 5	BMPUB	MUNI	21	21	Cameron	JAN-51	37.7
Silas Ray 6	BMPUB	MUNI	21	21	Cameron	JAN-61	27.7
Sim Gideon 1	LCRA	GOV	135	135	Bastrop	MAY-65	23.4
Sim Gideon 2	LCRA	GOV	135	135	Bastrop	JAN-68	20.7
Sim Gideon 3	LCRA	GOV	330	330	Bastrop	MAR-72	16.6
Stryker Creek 1	TU	IOU	175	175	Cherokee	JUN-58	30.3
Stryker Creek 2	TU	IOU	500	500	Cherokee	DEC-65	22.8
S.R. Bertron 1	HLP	IOU	174	174	Harris	MAR-58	30.6
S.R. Bertron 2	HLP	IOU	174	174	Harris	APR-56	32.5
S.R. Bertron 3	HLP	IOU	230	230	Harris	APR-59	29.5
S.R. Bertron 4	HLP	IOU	230	230	Harris	MAR-60	28.6
Thomas Ferguson 1	LCRA	GOV	425	425	Burnet	AUG-74	14.1
Tradinghouse 1	TU	IOU	565	565	McLennan	APR-70	18.5
Tradinghouse 2	TU	IOU	775	775	McLennan	JUN-72	16.3
Trinidad 5	TU	IOU	70	70	Henderson	DEC-49	38.8
Trinidad 6	TU	IOU	240	240	Henderson	MAY-65	23.4
T.H. Wharton 2	HLP	IOU	229	229	Fort Bend	JUN-60	28.3
Valley 1	TU	IOU	175	175	Fannin	NOV-62	25.9
Valley 2	TU	IOU	550	550	Fannin	DEC-67	20.8
Valley 3	TU	IOU	375	375	Fannin	MAY-71	17.3
Victoria 5	CPL	IOU	169	169	Victoria	MAR-63	25.5
Victoria 6	CPL	IOU	246	246	Victoria	MAY-68	20.4
V.H. Braunig 1	CPS	MUNI	220	220	Bexar	MAR-66	22.5
V.H. Braunig 2	CPS	MUNI	230	230	Bexar	APR-68	20.5
V.H. Braunig 3	CPS	MUNI	400	400	Bexar	MAY-70	18.4
Webster 3	HLP	IOU	374	374	Harris	MAY-65	23.4
Wilkes 1	SWP	IOU	177	177	Marion	MAY-64	24.4
Wilkes 2	SWP	IOU	351	351	Marion	MAY-70	18.3
Wilkes 3	SWP	IOU	351	351	Marion	DEC-71	16.8
W.A. Parish 1	HLP	IOU	176	176	Fort Bend	JUN-58	30.3

Natural Gas-Fired units Continued:

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	Date of Commercial Operation	Age
W.A. Parish 2	HLP	IOU	176	176	Fort Bend	DEC-58	29.8
W.A. Parish 3	HLP	IOU	278	278	Fort Bend	MAR-61	27.6
W.A. Parish 4	HLP	IOU	552	552	Fort Bend	JUN-68	20.3
W.B. Tuttle 1	CPS	MUNI	65	65	Bexar	JUN-54	34.3
W.B. Tuttle 2	CPS	MUNI	100	100	Bexar	DEC-56	31.8
W.B. Tuttle 3	CPS	MUNI	100	100	Bexar	MAY-61	27.3
W.B. Tuttle 4	CPS	MUNI	160	160	Bexar	MAR-63	25.5
Diesel Plant 1	BMPL	MUNI	2	2	Terry	JAN-51	37.7
Diesel Plant 3	BMPL	MUNI	3	3	Terry	JAN-64	24.8
Diesel Plant 4	BMPL	MUNI	3	3	Terry	JAN-54	34.7
Diesel Plant 5	BMPL	MUNI	4	4	Terry	JAN-57	31.7
Diesel Plant 6	BMPL	MUNI	4	4	Terry	JAN-61	27.7
Copper 1	EPE	IOU	69.4	69.4	El Paso	JUL-80	8.3
Greens Bayou G73-74,81-84	HLP	IOU	334	334	Harris	DEC-76	11.8
Holly St GT1	LPL	MUNI	12.5	12.5	Lubbock	JAN-63	25.7
Holly St GT2	LPL	MUNI	18	18	Lubbock	JAN-71	17.7
Holly St GT3	LPL	MUNI	22	22	Lubbock	JAN-74	14.7
H.O. Clarke G1-6	HLP	IOU	78	78	Harris	JUN-68	20.3
La Palma 7	CPL	IOU	43	43	Cameron	OCT-75	13.0
P.H. Robinson G1	HLP	IOU	13	13	Galveston	JUL-67	21.3
Sam Rayburn 1	STEC	COOP	10	10	Victoria	MAR-63	25.6
Sam Rayburn 2	STEC	COOP	10	10	Victoria	MAR-63	25.6
Silas Ray 7	BMPUB	MUNI	10	10	Cameron	JAN-68	20.8
Silas Ray 8	BMPUB	MUNI	43	43	Cameron	AUG-73	15.2
S.R. Bertron G1-2	HLP	IOU	36	36	Harris	JUL-67	21.3
T.H. Wharton G1	HLP	IOU	13	13	Harris	JUL-67	21.3
T.H. Wharton G31-34,41,42	HLP	IOU	13	13	Harris	JUL-72	16.
T.H. Wharton G43,44	HLP	IOU	84	84	Harris	AUG-74	14.2
T.H. Wharton G51-56	HLP	IOU	348	348	Harris	NOV-75	12.9
Webster G1	HLP	IOU	13	13	Harris	JUL-67	21.3
W.A. Parish G1	HLP	IOU	13	13	Fort Bend	JUL-67	21.3
Newman 4	EPE	IOU	211.6	211.6	El Paso	JUN-75	13.3
Rio Pecos 4	WTU	IOU	4	4	Crockett	MAY-54	34.4
San Angelo 1	WTU	IOU	29	29	Tom Green	JUL-65	23.2
T.H. Wharton 3,4	HLP	IOU	164	164	Fort Bend	AUG-74	14.2

HYDRO ELECTRIC UNITS

There are 32 Hydroelectric units in Texas with a total Net Dependable Capacity (NDC) of 520 MW.The majority of the units are operated by the Lower Colorado River Authority (LCRA). There are only 3 units owned and operated by an investor owned utility, the Eagle Pass units of Central Power & Light Company (CPL). The remainder are owned and operated by state or federal agencies. The average of all the hydro units is 44.8 years.

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	Date of Commercial Operation	Age
Abbott (TP-3)	GBRA	GOV	2.8	2.8	Guadalupe	JAN-28	60.8
Austin 1	LCRA	GOV	7.5	7.5	Travis	APR-40	48.5
Austin 2	LCRA	GOV	7.5	7.5	Travis	APR-40	48.5
Buchanan 1	LCRA	GOV	12.5	12.5	Llano	JAN-38	50.7
Buchanan 2	LCRA	GOV	12.5	12.5	Llano	JAN-38	50.7
Buchanan 3	LCRA	GOV	12.5	12.5	Llano	MAY-50	38.4
Denison 1	SPA	GOV	35	35	Grayson	JAN-44	44.8
Denison 2	SPA	GOV	35	35	Grayson	JAN-49	39.7
Dunlap (TP-1)	GBRA	GOV	3.6	3.6	Guadalupe	JAN-28	60.8
Eagle Pass 1	CPL	IOU	2	2	Mavrick	AUG-32	56.2
Eagle Pass 2	CPL	IOU	2	2	Mavrick	AUG-32	56.2
Eagle Pass 3	CPL	IOU	2	2	Mavrick	AUG-32	56.2
H-4	GBRA	GOV	2.4	2.4	Gonzales	JAN-32	56.8
H-5	GBRA	GOV	2.4	2.4	Gonzales	JAN-31	57.7
Inks	LCRA	GOV	11.5	11.5	Llano	JAN-38	50.7
Marshall Ford 1	LCRA	GOV	34	34	Travis	JAN-41	47.7
Marshall Ford 2	LCRA	GOV	25	25	Travis	JAN-41	47.7
Marshall Ford 3	LCRA	GOV	34	34	Travis	JAN-41	47.7
Morris Sheppard 1	BRA	GOV	12.5	12.5	Palo Pinto	JAN-41	47.7
Morris Sheppard 2	BRA	GOV	12.5	12.5	Palo Pinto	JAN-41	47.7
Nolte (TP-5)	GBRA	GOV	2.48	2.48	Guadalupe	JAN-28	60.8
Sam Rayburn 1	SPA	GOV	26	26	Jasper	JAN-66	22.7
Sam Rayburn 2	SPA	GOV	26	26	Jasper	JAN-68	20.8
Seguin (TP-4)	GBRA	GOV	2.4	2.4	Guadalupe	JAN-31	57.7
Starke 1	LCRA	GOV	16	16	Burnet	OCT-51	37.0
Starke 2	LCRA	GOV	16	16	Burnet	SEP-51	37.0
Toledo Bend 1	SRA	GOV	40	40	Newton	JAN-68	20.8
Toledo Bend 2	SRA	GOV	40	40	Newton	JAN-68	20.8
Whitney 1	SPA	GOV	15	15	Hill	JAN-55	33.7
Whitney 2	SPA	GOV	15	15	Hill	JAN-55	33.7
Wirtz 1	LCRA	GOV	26	26	Burnet	JUN-51	37.3
Wirtz 2	LCRA	GOV	26	26	Llano	AUG-51	37.3

UNITS USING ALTERNATE SOURCES OF ENERGY

There are 11 units in Texas that currently use alternate sources of energy, with a total Net Dependable Capacity (NDC) of 102 MW. The majority of these units use fuel oil or desiel fuel in internal combustion engines. The Celanese units could be considered cogeneration units, but are included here because Southwestern Public Service Company (SPS) owns the turbine generators portion of the units and operates them as regular units. The average age of these units is 18.6 years.

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	Date of Commercial Operation	Age
Lake Creek D	TU	IOU	6	6	McLennan	AUG-66	22.1
Lone Star 2	SWP	IOU	13	13	Morris	MAY-68	20.4
Lone Star 3	SWP	IOU	13	13	Morris	MAY-68	20.3
Lone Star 4	SWP	IOU	14	14	Morris	JUN-68	20.3
Morgan Creek D	TU	IOU	2.272	2.272	Mitchell	JAN-67	21.7
Permian Basin D	TU	IOU	1.136	1.136	Ward	JAN-67	21.7
Stryker Creek D	TU	IOU	10	10	Cherokee	JUL-66	22.2
Trinidad D	TU	IOU	4	4	Henderson	AUG-66	22.1
Celanese 1	SPS	IOU	10	10	Gray	MAR-65	23.6
Celanese 2	SPS	IOU	29	29	Gray	AUG-79	9.2
PV300 1	COA	MUNI	0.3	0.3	Travis	SEP-87	1.0

OPERATING UNITS NOT LOCATED IN TEXAS

This Section includes all operating units units not in texas but owned and/or operated by utilities regulated by the Public Utilitiy Commission of Texas. There are 5 Coal-Fired Units with a Net Dependable Capacity (NDC) of 1,014.8 MW. There is one Lignite-Fired unit, with a Net Dependable Capacity (NDC) of 295 MW. There are 22 Natural Gas-Fired units with a total Net Dependable Capacity (NDC) of 3,939 MW. There are 4 Nuclear Units with a Net Dependable Capcity (NDC) of 1,255 MW.

Plant name	Reporting Utility	Utility Type	NDC	NDC Owned	County	State	Date of Comercial Operation	Age
Big Cajun II 3	GSU	IOU	540	226.8	Pointee Coupee	LA	SEP-83	5.1
Flint Creek 1	SWP	IOU	480	240	Benton	AR	MAY-78	10.4
Four Corners 4	EPE	IOU	55	55	San Jaun	NM	JUL-69	19.2
Four Corners 5	EPE	IOU	55	55	San Jaun	NM	JUL-70	18.2
Nelson 6	GSU	IOU	550	385	Calcasieu	LA	MAY-82	6.3
Nelson 6	SRGT	COOP	550	54	Calcascieu	LA	MAY-82	6.3
Dolet Hills 1	NTEC	COOP	640	38	Desoto	LA	APR-86	2.4
Dolet Hills 1	SWP	IOU	640	258	DeSoto	LA	APR-86	2.4
Arsenal Hill 5	SWP	IOU	113	113	Caddo	LA	APR-60	28.5
Carlsbad GT1	SPS	IOU	16	16	Eddy	NM	DEC-77	10.8
Cunningham 1	SPS	IOU	71	71	Lea	NM	JUL-57	31.3
Cunningham 2	SPS	IOU	196	196	Lea	NM	JUL-65	23.3
LA Sta. #1	GSU	IOU	145	145	E. Baton Rouge	LA	DEC-38	49.8
Lieberman 1	SWP	IOU	27	27	Caddo	LA	JUL-47	41.2
Lieberman 2	SWP	IOU	29	29	Caddo	LA	APR-49	39.4
Lieberman 3	SWP	IOU	111	111	Caddo	LA	JUN-57	31.3
Lieberman 4	SWP	IOU	109	109	Caddo	LA	MAY-59	29.4
Maddox	SPS	IOU	118	118	Lea	NM	JAN-67	21.7
Maddox GT	SPS	IOU	66	66	Lea	NM	JAN-76	12.8
Nelson 1	GSU	IOU	100	100	Calcasieu	LA	MAR-59	29.5
Nelson 2	GSU	IOU	100	100	Calcasieu	LA	JUN-59	29.3
Nelson 3	GSU	IOU	146	146	Calcasieu	LA	MAR-60	28.5
Nelson 4	GSU	IOU	500	500	Calcasieu	LA	JUL-70	18.2
Rio Grande 6	EPE	IOU	48	48	Donna Ana	NM	JUN-57	31.3
Willow Glen 1	GSU	IOU	146	146	Iberville	LA	MAR-60	28.5
Willow Glen 2	GSU	IOU	198	198	Iberville	LA	JAN-64	24.7
Willow Glen 3	GSU	IOU	500	500	Iberville	LA	DEC-68	19.8
Willow Glen 4	GSU	IOU	500	500	Iberville	LA	JUL-73	15.2
Willow Glen 5	GSU	IOU	550	550	Iberville	LA	JUL-76	12.2
Rio Grande 8	EPE	IOU	150	150	Donna Ana	NM	JUL-72	16.2
Palo Verde 1	EPE	IOU	1270	200	Maricopa	AZ	DEC-85	2.8
Palo Verde 2	EPE	IOU	1270	200	Maricopa	AZ	SEP-86	2.0
Palo Verde 3	EPE	IOU	1270	200	Maricopa	AZ	JAN-88	0.7
River Bend 1	GSU	IOU	936	655.2	W. Feliciana	LA	JUN-86	2.3