TABLE 4.2

RESIDENTIAL RATE STRUCTURES IN TEXAS FOR MAJOR UTILITIES (AS OF OCTOBER 1992)

Utility	Customer Charge	Residential Service Energy Charge ($/KWH)	Residential Space Heating Rider ($/KWH)
TU Electric	$6.00	Summer Charge (May - Oct.) i) All KWH: $.0550	
		Winter Charge (Nov. - April) i) 0 to 600 KWH: $.0550 ii) Beyond 600 KWH: $.0265	
HL&P	$6.81	Summer Charge (May - Oct.) i) 0 to 250 KWH: $.023545 ii) Beyond 250 KWH: $.082608	
		Winter Charge (Nov. - April) i) 0 to 250 KWH: $.023545 ii) 251 to 800 KWH: $.082608 iii) Beyond 800 KWH: $.047232	
GSU	$6.24	Summer Charge (May - Oct.) i) All KWH: $.05896	
	$6.24	Winter Charge (Nov. - April) i) 0 to 1,000 KWH: $.05896 ii) Beyond 1,000 KWH: $.03896	
CPL	$7.04	Summer Charge (April - Nov.) i) All KWH: $.0573	Summer Charge (April - Nov.) i) All KWH: $.0573
	$7.04	Winter Charge (Dec. - March) i) All KWH: $.0481	Winter Charge (Dec. - March) i) 0 to 800 KWH: $.0481 ii) Beyond 800 KWH: $.0298
SPS	$4.66	i) All KWH: $.0393	Winter Charge (Nov. - May) i) 0 to 500 KWH: $.0393 ii) Beyond 500 KWH: $.0086
SWEPCO	$7.00	Summer Charge (May - Oct.) i)All KWH: $.0453	
		Winter Charge (Nov. - April) i) 0 to 600 KWH: $.0352 ii) 601 to 2500 KWH: $.0203 iii) Beyond 2500 KWH: $.0352	
LCRA	$8.00	i) All KWH: $.04238	

TABLE 4.2
(continued)

RESIDENTIAL RATE STRUCTURES IN TEXAS FOR MAJOR UTILITIES (AS OF OCTOBER 1992)

Utility	Customer Charge	Residential Service Energy Charge ($/KWH)	Residential Space Heating Rider ($/KWH)
COA	$3.00	Summer Charge (May - Oct.) i) 0 to 500 KWH: $.0275 ii) Beyond 500 KWH: $.0782	
		Winter Charge (Nov. - April) i) 0 to 500 KWH: $.0275 ii) Beyond 500 KWH: $.0582	
WTU	$6.50	Summer Charge (May - Oct.) i) All KWH: $.0572	Summer Charge (May - Oct.) i) All KWH: $.0572
	$6.50	Winter Charge (Nov. - April) i) All KWH: $.0472	Winter Charge (Nov. - April) i) 0 to 500 KWH: $.0472 ii) Beyond 500 KWH: $.0297
EPE	$4.50	Summer Charge (June - Sept.) i) All KWH: $.08123	
	$4.50	Winter Charge (Oct. - May) i) All KWH: $.07623	
TNP*	$5.50	Summer Charge (May - Oct.) i) 0 to 400 KWH: $.04646 ii) Beyond 400 KWH: $.09906	
	$5.50	Winter Charge (Nov. - April) i) 0 to 400 KWH: $.04646 ii) Beyond 400 KWH: $.09156	
SESCO**	$7.50	Summer Charge (June - Nov.) i) All KWH: $.06505	
	$7.50	Winter Charge (Dec. - May) i) 0 to 800 KWH: $.06505 ii) Beyond 800 KWH: $.0492	

* Bonded rates

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

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

TABLE 4.3

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

	1992	2000
HL&P	851	417
TU Electric	453	588
CPL	318	367
GSU	91	91
SWEPCO	58	58
SPS	22	73
LCRA	15	50
TNP	2	2
BEPC	1	93
WTU	0	0
CPS	0	0
TOTAL	1,811	1,739

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

As indicated in Table 4.3, most of the large generating utilities in Texas serve a portion of their large industrial customer load under interruptible rates. These utilities reduced their capacity requirements by a combined 1,800 MW in 1992 through their interruptible rate programs. The design of interruptible rates varies considerably among these utilities.

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

HL&P now offers a number of interruptible rates, including: IS-30, where the customer is required to curtail service within 30 minutes of notification; IS-10, where 10-minute notice is provided to the customer; and IS-I, a new instantaneous interruptible service similar to TU

Electric's. HL&P expects use of interruptible service to decrease over time as reserve margins decline and curtailments increase in frequency. Future use of interruptible service will also be affected by the status of the utility's cogeneration contracts, self-generation activity, the differential between the prices of firm and interruptible service, and changes in tariff terms and conditions.

GSU offers interruptible rates with 30- and 5-minute notice requirements, and also has a no-notice interruptible rate.

CPL offers three interruptible service riders. The first provides for the automatic interruption upon a specified drop in system frequency and the second provides for interruption based on the discretion of CPL but not due to under-frequency relay control equipment. CPL will, however, try to provide at least 15-minute advance notice for instantaneous service interruption. CPL also offers "true" advance-notice interruptible service where customers are provided 15-minute notice when a service interruption is deemed necessary.

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

SPS offers instantaneous interruptible contracts under two categories: (1) wholesale interruptible loads, where SPS sells 30 MW of interruptible power to El Paso Electric Company and 100 MW of interruptible power to Public Service Company of New Mexico; and (2) wholesale non-firm energy where SPS sells energy to several utilities for resale. Additionally, SPS offers customer-notification interruptible contracts to wholesale rural electric cooperative customers participating in Irrigation Scheduling Load Management Program and an Interruptible Irrigation Program, electrical-melting-service customers, and the Canadian River Municipal Water Authority.

SWEPCO offers five interruptible contracts: one instantaneous; and four customer-notification. The company is expected to provide at least 30-minute notice in most instances.

LCRA does not offer instantaneous interruptible service. However, the company offers interruptible service upon 120-minute verbal notice.

WTU offers both instantaneous and 15-minute-notice interruptible services to its customers.

TNP offers interruptible service to customers taking service under industrial and irrigation service tariffs. The notification and interruption parameters for industrial customers are subject to contractual negotiations. The irrigation service customers agree not to operate during the company's peak hours during the months of June through September and their interruption time will be limited to eight hours a day.

BEPC offers interruptible service which can be interrupted with or without notice to the customers.

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

HL&P's IS-B rate, a predecessor to the current IS-I and IS-10 tariffs, served between 10 and 15 large industrial customers between 1985 and 1987. Most of these customers also took service under one of the utility's firm rates, and many also had their own generating capability which they could rely upon in the event of an interruption or anticipated high prices. Prices were determined by hourly system marginal costs calculated by the company's GENSOM production costing model. A problem with this rate was that the customers did not know the exact prices they were facing until after the fact (the marginal cost calculations were made ex post). Distrust of the utility's marginal cost calculations motivated changes in the structure of this rate. In 1987, this was modified into a more traditional time-of-use rate. However, the idea of basing HL&P's new interruptible rates on real-time pricing concepts is now being explored again.

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

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

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

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

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

In their current forecasts, the utilities in Texas have reduced their peak demand forecasts by 1,739 MW in the year 2000 for interruptible service programs. The Commission staff has evaluated these projections and generally recommends their adoption as adjustments to the Commission staff's peak demand forecast. A further discussion is provided in Chapter 5.

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

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

1990 Amendments to the Clean Air Act Compliance Strategy

Request 9.02 was included for the first time in the 1991 Long-Term Electric Peak Demand and Capacity Resource Forecast filings. This request was designed to obtain information from the electric utilities in Texas concerning their preliminary plans for compliance with the 1990 Amendments to the Clean Air Act. The following is a summary of the responses to questions in request 9.02.

Identify New Units Phase I emission limitations for existing units[1] specifically identified in Section 403 of the Act are effective January 1, 1995. These units are required to reduce SO_X emissions to 2.5 lbs per MMBtu multiplied by baseline[2] fuel consumption, or hold sufficient allowances[3] equal to unit emissions, by the effective date. No generating unit in Texas is an affected unit[4] in Phase I.

Phase II emission limitations for existing units are effective January 1, 2000. Essentially all Texas fossil fuel-fired generating units are affected units in Phase II. In Phase II, units which had 1985 emissions of more than 1.2 lbs of SO_X per MMBtu will be issued allowances limited to 1.2 lbs per MMBtu multiplied by baseline fuel consumption. Units which have 1985 emissions of less than 1.2 lbs of SO_X per MMBtu will generally be issued allowances equal to the 1985 emission rate multiplied by baseline fuel consumption. Four units in Texas have 1985 emissions greater than 1.2 lbs per MMBtu. These units are all operated by TU Electric: Big Brown 1 and 2, and Monticello 1 and 2.

Certain units which were planned or under construction at the date of enactment of the amendments will be issued partial annual allowances, as specified in Section 405(g) of the Act. In Texas, these units are TNP One 2 (TNP), Spruce 1 (CPS), Twin Oak 1 and 2 (TU Electric), and Malakoff 1 (HL&P).

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1 "Existing Unit" means a unit that commenced commercial operation before the date of enactment of the Clean Air Act Amendments of 1990. Existing units shall not include simple combustion turbines or units with a capacity of 25 MW or less.

2 "Baseline" means the annual quantity of fossil fuel consumed by an affected unit, measured in MMBtu. Generally, the baseline shall be the annual average quantity of MMBtu's consumed in fuel during calendar years 1985, 1986, and 1987.

3 "Allowance" means an authorization to emit, during or after a specified calendar year, one ton of sulfur dioxide (SO_2).

4 "Affected Unit" means a unit that is subject to emission reduction requirements or limitations under the Act.

New units[5] will not be issued allowances. The utility must acquire allowances for these units through self generation, purchase on the open market, purchase at auction, or other transactions. A utility is not permitted in any year to emit SO_X in amounts greater than the allowances held by the utility for that year.

Identify Compliance Strategy Generally, the utilities responding to this request have not yet finalized compliance plans. Most are waiting until the EPA publishes its final rules governing the implementation of the Act, and the final EPA allowance data base. Simply stated, the utilities intend to adopt strategies which will provide sufficient emission allowances to operate existing and planned units through reduction of emissions on existing units or through purchase of allowances, depending upon which is more cost effective.

In the near term, no utility in Texas foresees a significant shortfall in allowances. The industry warns of several factors which could greatly influence the need and availability of allowances in the future:

1. Given any significant increase in oil consumption due to gas availability or cost, additional allowances will be needed to meet existing electrical demand.
2. Additional electrical capacity to meet future growth will require associated allowances.
3. In order to meet the mandated 8.9 million ton annual limit on SO_X emissions, the EPA will "ratchet down" or decrease all basic allowance allocations on a pro rata basis. This "ratcheting down" may reach as high as 10 percent across the board for all units.
4. Possible regulatory restrictions on the movement of allowances between states.

Several utilities pointed out that other provisions of the Act will result in financial impacts:

- Title I will likely require emissions reductions related to air quality in nonattainment areas in Texas.
- Title II and current state laws could require conversion of centrally-fueled fleet vehicles to alternative fuels.
- Title III may require development and implementation of emissions controls for major sources of hazardous air pollutants.

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5 "New Unit" means a unit that commences commercial operation on or after the date of enactment of the Clean Air Act Amendments of 1990.

- Title IV also contains NO_X reduction and continuous emissions monitoring (CEM) requirements.
- Title V includes comprehensive permitting requirements and new permit fees.

Bonus Allowances

> **Section 404(f):** For emissions avoided through energy conservation and renewable energy programs implemented after January 1, 1992, a total of 300,000 bonus allowances are provided.

TU Electric and the City of Austin believe that they will qualify for these bonus allowances under the conservation plans that are currently in place. Most other utilities are not sure if their plans will qualify under the guidelines established in the Act. Many believe that these conservation and renewable bonuses will be consumed by utilities that are aggressively pursuing demand-side management and renewable energy options in states that have a formal least-cost planning process.

> **Sections 405(h)(2) and (3):** For oil- and gas-fired units whose average annual fuel consumption during the period 1980 through 1989 was less than 10 percent oil, provides annual bonus allowances equal to the unit's baseline fuel consumption multiplied by 0.050 lbs per MMBtu beginning in year 2000.

Most gas-fired units in Texas were eligible for these bonus allowances had the Governor not elected the bonuses under Section 406 instead.

> **Section 406:** Upon election of the Governor of any state with a 1985 state-wide annual SO_X emissions rate equal to, or less than, 0.80 lbs per MMBtu, annual allocation in an amount equal to 125,000 multiplied by the unit's pro rata share of electricity generated in calendar year 1985 at units in all states eligible for the election. These allowances will be allocated annually from year 2000 through 2009, and will be distributed in lieu of other bonus allowance allocations for which the unit is eligible.

The Governor has elected Section 406 treatment for Texas. Under this election, more allowances are allocated to Texas as a whole than under alternative bonus provisions in the Act. GSU, EPE, and several other utilities are allocated fewer allowances under Section 406 in Texas than under alternative bonus provisions. WTU will receive fewer allowances under a Section 406 election; however, the CSW system as a whole will receive more allowances under Section 406 than alternative bonus provisions.

Louisiana is eligible for Section 406 election, and it has made such an election. GSU is allocated more allowances in Louisiana under Section 406 than under alternative bonus provisions. New Mexico is also eligible for Section 406 election, and it has made such an election. EPE is allocated more allowances in New Mexico under Section 406 than under alternative bonus provisions.

Allowance Trading If an affected utility emits SO_X without corresponding allowances in a given year, the utility will be penalized $2,000 per ton, and the excess emissions must be offset in the next year.

Most utilities in Texas project that they will not generate a substantial number of excess allowances. However, because of the severe penalty for emitting SO_X without allowances, utilities will generally bank any excess allowances they may generate to insure against unexpected emission control upsets and for future units.

Costs and Revenues The utilities have not fully determined how they plan to treat compliance costs and revenues. Generally, however, they will include any required construction costs related to compliance in plant in service, and as such, the costs will be subject to depreciation. This depreciation expense will be included in cost of service with the undepreciated balance of the construction costs included in rate base. Additional O&M expense will be included in cost of service.

GSU believes that if it ultimately makes some allowance sales, any gains or losses on such sales should be shared appropriately between shareholders and ratepayers. Ratepayers should receive some benefit since they have paid compliance costs which result in having excess allowances available to be sold. However, utility shareholders should receive a large enough share of gains to provide an incentive for utilities to trade emission allowances.

SWEPCO proposes that the EPA's annual allocation of allowances to units in the rate base should belong to the ratepayer. When these allowances are consumed by the unit, it is at no cost to the ratepayer. If the unit receives allowances in excess of its needs (including a reserve margin) that are sold, the revenue could be booked against fuel expenses. If a unit increased operating expenses to generate allowances for sale, the net revenue could be credited to fuel.

A preliminary assessment of the number of allowances granted to selected utilities in Texas is shown in Table 4.4.

TABLE 4.4

BASIC EMISSIONS ALLOWANCES GRANTED UNDER THE CLEAN AIR ACT AMENDMENTS OF 1990

Utility	Basic	Standard Bonus	Clean State Bonus
Central Power and Light	16,421	2,957	3,684
El Paso Electric	0	173	123
Gulf States Utilities	8	2,724	2,162
Houston Lighting and Power	114,979	6,598	10,503
Lower Colorado River Authority	30,930	767	1,468
Southwestern Electric Power	63,492	441	2,906
Southwestern Public Service	63,980	395	3,298
Texas-New Mexico Power	6,562	0	0
Texas Utilities	279,400	9,874	17,039
West Texas Utilities	5,413	956	803
Brazos Electric Power	8,513	385	654
South Texas Electric	8,510	0	291
City of Austin	18,934	557	1,349
City of San Antonio	35,173	1,614	2,314
Texas Municipal Power Agency	15,912	0	527
Total	668,227	27,441	47,121

Target Reserve Margin

Target reserve margin, the minimum reserve margin that a utility has to maintain annually to ensure the reliability of the electricity supply, is an important factor in determining the need for additional capacity, which can greatly affect the price of electricity. Statewide, every percent of the reserve margin may translate into more than $100 million annually to the ratepayers.

The major generating utilities serving Texas provided studies on target reserve margin. Except for TNP, which relies on its suppliers for reserves, utilities analyze the reserve margin requirements on a periodical basis. Most utilities, except HL&P, use the loss of load probability (LOLP) approach in their studies. HL&P recently started to employ a "value-based" technique in its analysis.

An LOLP approach relies on a probability that the system will not be able to fully meet its demand obligation. The unit of LOLP is expressed in days/year or hours/year. During any given hour, there is a probability that each of the power plants on-line may have to reduce output or be taken off line for maintenance or repair. Each hour, a small probability exists that several power plants will be out of service at the same time such that the remaining active power plants cannot fully meet the demand. The LOLP is the sum of this probability from every hour in a year. Note that an LOLP is only a mathematical index to measure the relative reliability of the system. It does not represent any projection of the system outages.

In the process of determining the LOLP, the expected unserved energy (EUE) can also be determined. From a system operating standpoint, EUE is the electric energy that has to be curtailed when shortages occur. In the valued-based approach, the total cost associated with all unserved energy is calculated. This cost estimates loss of manufacturing output, equipment damages, and other social costs due to outages. If the total cost of unserved energy exceeds the cost of additional supply, capacity is added. On the other hand, if the total cost of unserved energy is lower than that of additional supply, the amount of additional supply is reduced. In theory, the optimum reserve is found where the marginal cost of unserved energy is equated to the marginal cost of additional supply.

Utilities do not depend entirely on an LOLP study to make a final determination on the reserve margin requirements. There are other criteria set by various reliability councils with which the utilities must comply. Of the 13 utilities that reported reserve margin studies, EPE is a member of WSCC; GSU, SPS, and SWEPCO are members of SPP; and the remaining nine utilities are members of ERCOT.

For WSCC, one of the following conditions must be met: (1) 15% reserve margin or the largest unit plus 5%, (2) sum of the two largest contingencies, or (3) an LOLP of no more than 0.1 days per year. SPP requires the minimum reserve margin to be between 15% and 18%, depending on the capacity mix of the member utility. As reported by GSU and SWEPCO, SPP conducted a formal study using LOLP to support its 15-18% reserve margin requirement. ERCOT requires a minimum reserve margin of 15%.

The target reserve margins for the reporting utilities are summarized below:

TU Electric	18.0%
HL&P	18.0%
GSU	15.3%
CPL	18.0% or largest unit
CPS	17.0-18.0%
SPS	15.0%
SWEPCO	15.0%
LCRA	15.0%
COA	no more than 18.0%
WTU	15.0%
EPE	largest unit plus 5.0%
TNP	no requirement
BEPC	15.0% (combined reserve margin with Texas Municipal Power Pool)

Potential for Increased Power Transactions

Two studies conducted by the Electric Division staff suggest that there is a potential economic gain from an increase in power interchange among utilities and purchases from qualifying facilities. In the short term, these transactions may result in a more efficient use of resources to reduce fuel costs. In the long term, new capacity could be deferred.

Nine ERCOT utilities were requested to provide a study identifying the potential for increased transactions with other utilities and qualifying facilities. These utilities include TU Electric, HL&P, CPL, CPS, LCRA, COA, WTU, TNP, and BEPC. This request was limited to ERCOT utilities because they form a transmission network that is isolated from the other utilities serving Texas. Although a DC tie exists among the CSW companies, its capacity is too small to allow any significant interchange between utilities in ERCOT and utilities in other reliability councils.

No utility within the ERCOT system provided a comprehensive and quantitative study analyzing interutility transactions. Rather, the utilities provided only qualitative discussions. As indicated by CPL, a quantitative analysis of this type would be time consuming. Due to risks associated with uncertainty in price and availability in future markets, several utilities do not make any specific plans on purchased power.

Most utilities actively participate in the ERCOT economy programs for short-term interchange. The transmission network appears to be adequate to meet the current level of interchange. While inter-utility transactions are commonly used by ERCOT utilities to meet hour-to-hour system needs, no serious action has been taken by these utilities to enter into long-term power contracts.

For long-term planning purposes utilities continue to evaluate offers from qualifying facilities to satisfy their capacity needs. CPS's negotiations with potential QF suppliers failed to secure contracts because no offers were below the projected costs of its own power plant. BEPC had a similar experience. An unspecified amount of TU Electric future capacity needs will be met by non-utility generating sources.

Given the existence of about 6,000 MW of surplus capacity within ERCOT in 1992, inter-utility transactions could improve electric resource use within the state. There are restrictions however. Utilities with excess capacity, such as LCRA and COA, are not looking for potential suppliers or long-term buyers. Neither have enough capacity to sell under a long-term contract. Further, COA and CPS cannot freely sell excess capacity; doing so will result in the loss of tax-exempt status for their bonds. BEPC and other cooperatives have a similar restriction imposed by the REA in the use of funds.

Due to restrictions in long-term supply contracts between utilities, future external sources are more likely to come from QFs. In the next ten years, close to 2,500 MW of QF contracts will be expiring. These contracts could be renewed and displace several future units that are currently planned.

<u>CHAPTER FIVE</u>

DEMAND-SIDE RESOURCES

Introduction

For more than a decade, demand-side resources have made an economical contribution to the resource mix of major generating electric utilities by reducing peak demand requirements. Several electric utilities in Texas were innovators in the development of customer rebate programs for high-efficiency air conditioners starting in 1980 and 1981. TU Electric and HL&P found that they could slow the growth in peak demand, defer hundreds of megawatts of capacity, reduce their capital needs, and reduce electric generation at critical periods with these targeted conservation programs. These types of demand-side management (DSM) programs offer an additional resource option.

Integrated resource planning (IRP) represents the formal consideration of all resource options, both demand-side and supply-side, in an integrated framework. The IRP approach has received favor among utilities and regulatory agencies that hope to avoid the addition of unnecessary capacity. The IRP framework is also useful in analyzing a broad spectrum of issues such as external costs and competition.

The Texas Legislature's 1983 amendments to the Public Utility Regulatory Act (PURA) gave the Commission some guidance in the regulation of power plant licensing and long-term planning. The Commission incorporated the amendments to PURA through staff review of utility energy efficiency plans and load and capacity resource forecasts, the development of a statewide electrical energy plan, the processing of notice of intent applications, the licensing of power plants, and the approval of certain purchased power contracts.

Energy efficiency plans are required for the major utilities. These plans contain descriptions and cost-benefit analysis data for efficiency projects and programs including supply-side and demand-side resources. The Commission's notice of intent process is the first stage of a two-step power plant licensing procedure. The effectiveness of this ad hoc procedure has been limited by the lack of applications during the Texas recession, and a lack of definition regarding the purpose of the notice of intent and the certificate of convenience and necessity proceedings.

While Texas dealt with important nuclear-plant-in-service rate case issues, other state commissions grappled with cost-effectiveness issues and the disincentives associated with conservation programs. Regulators in Texas are now focused on these issues including the treatment of DSM expenditures, lost revenues, and regulatory incentives for DSM.

Definitions Demand-side management is the set of utility-initiated programs intended to economically alter the timing and magnitude of customer energy usage. DSM activities provide an expanded selection of electric service options for customers that want to control their energy costs, use new efficient devices, or otherwise modify their behavior to their advantage. DSM includes a system planning resource (e.g. lower peak demand or conserved energy) or a system impact (e.g. increased usage).

Just over ten years ago, the Electric Power Research Institute coined the term demand-side management to encompass utility-initiated demand-shaping actions. These include the traditional load shape objectives of shaving peak (now called peak clipping), peak shifting, and off-peak sales promotion (now called valley filling), as well as strategic additions (strategic load growth) and reductions in load (strategic conservation), and flexible load shape. These six load shape objectives are best illustrated with simple examples:

Load Shape Objective	Example
Peak Clipping	Appliance cycling by direct utility control
Load Shifting	Nighttime "cool storage" on the customer's premises
Valley Filling	Security lighting (nighttime) promotion and off-peak sales (winter) promotion through fuel-switching to electric heat pumps
Strategic Conservation	Equipment efficiency, which focuses on peak usage
Strategic Load Growth	Industrial electrification and economic development to increase usage and customer value
Flexible Load Shape	Interruptible loads, which allow control of system load shape throughout the year

Conservation generally refers to reduced use of natural resources. In the context of electric system planning, it refers to reduced energy usage *at any time*. Utility-sponsored *strategic* conservation programs focus on energy efficiency improvements during peak-demand periods. High-efficiency air conditioner promotion programs are called *strategic conservation* because hot Texas weather, specifically through space cooling loads, drives summer peak demands.

Energy efficiency refers to reducing the quantity of electricity needed to deliver a given level of energy services to customers. Demand-side efficiency focuses on the energy efficiency of electricity-consuming buildings, appliances, or industrial processes without any reduction in comfort or output. Supply-side efficiency results from reducing the losses in the generation, transmission, and distribution of electricity.

The term load management, as it is frequently used, refers to programs which reduce peak demand and which have little, if any, impact on energy consumption. For example, load shifting from peak to off-peak periods may not change annual energy usage. Some utility planners use load management to refer to all DSM. Depending on the context, load management refers to direct load control (peak clipping), load shifting, valley filling, or a combination of these and other activities.

It is useful to distinguish between active and passive DSM. Active DSM is dispatchable and includes the interruption of industrial, municipal, and agricultural loads or appliance cycling programs. These activities require a signal to a device or customer. Utility control may be direct (as in under-frequency relays for instantaneous interruptible loads), or indirect through telephone communication.

Passive DSM is typically not dispatchable and involves utility-initiated efforts on the front end. Once implemented, however, the utility merely monitors the effects. Building insulation is a good example of passive DSM: it has high availability and reliability; it is not subject to utility control or reversibility; and it is non-dispatchable (since it is always in place and has a persistent and predictable impact).

All resource decisions -- whether demand-side or supply-side -- are based on estimates of the future. DSM program planners begin with preliminary engineering estimates of program impacts and costs. Pilot programs allow a utility to monitor and verify these estimates. DSM program evaluation is an essential component of integrated resource planning. Evaluation requires nontraditional techniques and thus is unfamiliar to some system planners. (By comparison, the measurement of power plant success is so basic that we hardly mention it.) There are two basic types of DSM program evaluation: process evaluation and technical evaluation. Process evaluation examines the activities that a utility must undertake to implement and track a program. The interactions of the various departments and groups are examined to identify opportunities for streamlining the process and reducing bottlenecks. A market evaluation may be part of a process evaluation or it may be a separate exercise. Technical evaluation, also referred to as impact evaluation, is performed to improve the savings estimates. Improved technical evaluations are essential for the data used in utility planning decisions, cost recovery decisions, and regulatory treatment.

Energy Efficiency Goals for Texas

Electric utilities in Texas should assure the maintenance of a reliable electrical system capable of providing low-cost energy services to consumers. Demand-side resource alternatives should be included to increase energy efficiency.

The Commission should implement a regulatory review and power plant licensing process that assures that the public interest is served. The regulatory process should ensure that the utilities' forecasting and planning methods fairly assess all reasonable resource alternatives. Further, the Commission should encourage rational and orderly competition among the suppliers of end-use energy services.

The Commission is in many ways just beginning to establish long-term statewide planning goals. Current practice, with few exceptions, has been to rely on the utilities' planning goals. In the past, these goals have been to meet future electrical needs through the acquisition of generating capacity. Some utilities have added capacity from qualifying cogenerators and others have embraced load management programs; however, most utilities have tried to minimize rates and risk through their own construction programs. This approach is limited given a changing electricity market.

In 1986 the staff rejected the utilities' estimates of DSM program impacts and recommended that the major utilities achieve a 12 percent peak demand reduction over a 10-year period through conservation and load management programs. This explicit demand-side resource goal was rejected by the utilities in subsequent proceedings and received limited support from the Commission. Currently, staff believes that it is premature to once again recommend a comprehensive set of resource planning goals for Texas. The focus of recent staff efforts has instead been the establishment of an appropriate resource planning process.

In general, utilities in Texas lack a corporate commitment to demand-side resource acquisition. A review of current utility activities reveals limited implementation of appropriate energy efficiency objectives:

1. Few utilities have a comprehensive set of DSM programs with aggressive market penetration and participation rates.
2. Few utilities have explored alternative rate designs to improve retail pricing that encourages end-use energy efficiency.
3. Existing DSM efforts focus on peak demand reduction, not energy efficiency to reduce consumption and lower consumer bills.
4. Many utilities are implementing programs that increase sales, often without adequate attention to end-use energy efficiency of long-term system costs.
5. Many utilities are implementing fuel switching programs which encourage customers to replace fossil-fuel appliances with electrical appliances.
6. No utility has thoroughly investigated a reasonable set of renewable resource alternatives for customers such as passive solar heating.
7. No utility has thoroughly investigated DSM programs to defer transmission and distribution system investments.
8. Most utilities concentrate on residential programs while the commercial and industrial sectors frequently have greater DSM potential.
9. With the exception of LCRA, inadequate attention has been paid to the design of wholesale tariffs or to the provision of DSM programs for the retail customers of nongenerating utilities.

A commitment to energy efficiency is a prerequisite for the selection of demand-side resources and the implementation of effective DSM programs. Utilities should establish peak-demand reduction as a goal along with the reduction in usage generally.

Background

Barriers to Energy Efficiency

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

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

DSM programs play a role in overcoming these barriers by providing information about efficient technology and the efficient use of energy and by lowering the payback on energy efficiency investments to program participants through rebates or low interest loans. But under the prevailing regulatory climate, a utility is often penalized for providing these services. Typically, a utility engaged in large DSM programs will not receive a return on its DSM investments and will lose revenues due to DSM-related lost sales. One remedy is to allow utilities to profit from their DSM investments and recover their lost revenues.

Regulatory Incentives and Disincentives for Energy Efficiency

Traditional regulation inhibits the even-handed consideration of demand-side resources. Rate-of-return regulation results in utility incentives to promote sales and cut costs between rate cases. Lower sales decrease cash flow and profits, creating a disincentive for energy efficiency programs. This continues until the next rate case when the impact of conservation and promotional activities is "trued up." There is nothing surprising, or troubling, in this finding, particularly if you are comfortable with the notion that the business of electric utilities is the marketing of a commodity -- kilowatt-hours. The view of electricity as a commodity is unrealistic in an increasingly competitive world.

Electric utilities provide energy services, and the most competitive utilities will offer the lowest-cost energy services, not necessarily the lowest-cost per kilowatt-hour. An energy service view is consistent with the encouragement of demand-side efficiency.

A number of regulatory commissions have modified traditional practice to address the conflict between profitability and the encouragement of end-use energy efficiency. Numerous mechanisms encourage even-handed consideration of demand-side resources:

1. Provide full and timely recovery of DSM expenditures.

2. Allow utilities to capitalize DSM expenditures and earn a rate of return on such investments.
3. Allow utilities a bonus rate of return on DSM investments or on total rate base.
4. Allow utilities a share of the savings, whereby their shareholders retain a portion of the net benefits of DSM programs.
5. Allow utilities to recover the lost revenues associated with DSM programs.
6. Allow utilities to decouple profits from sales to eliminate the lost revenue problem.

The PUCT has some of these mechanisms in place and others under consideration. Staff is investigating a variety of DSM incentives to determine the appropriate regulatory mechanisms.

1. <u>DSM Cost Recovery</u>: The PUCT's energy efficiency plan rule allows recovery of these expenditures; however, some parties question the certainty and timeliness of recovery. An annual "DSM Cost Recovery Factor" would adjust revenues outside of a major rate case. The factor could include some of the items cited below.
2. <u>Capitalization</u>: The PUCT's energy efficiency plan rule allows capitalization to allow a return on these expenditures. Utilities prefer to expense DSM, however, in part because capitalization treatment is considered less certain than expensing.
3. <u>Bonus rate of return</u>: The PUCT's rules allow adjustment of the rate of return for achievements in the conservation of resources. This mechanism affects return dollars (and thus total return) and has been explicitly applied three times.
4. <u>Shared Savings</u>: Shared savings options have not been attempted for DSM in Texas. A share of net benefits could appear as an expense in a major rate case, as an adjustment to the rate of return, or as part of a "DSM Cost Recovery Factor."
5. <u>Lost Revenues</u>: Once tariffs are established, reductions in anticipated sales represent "lost revenues" from the utility's point of view. The calculation of lost revenues is non-trivial. Lost revenue recovery mechanisms are not currently part of the Texas regulatory scheme.
6. <u>Decoupling</u>: The decoupling of sales levels from profits and the re-coupling of customers (or some other factor) with profits will shift risk from the utility to the customers. Some states have instituted this mechanism to determine whether utilities have an incentive to reduce customers costs through conservation programs.

Integrating Demand-Side Resources into the Long-Term Plan

Once demand-side resources have been identified, they can be integrated into the resource plan sequentially or simultaneously. In a sequential approach, demand-side resources are selected first, and then supply-side resources are optimally committed. This approach is most common among utilities nationwide and in Texas. TU Electric, for example, commits to serve 20 percent of its growth in peak demand through demand-side resources. First, DSM programs are designed and financial resources are committed to achieve that level of peak-demand reduction. Next, supply-side resources are considered to serve the adjusted forecast -- the forecast net of the 20 percent of growth which will be served by the projected DSM activities.

The simultaneous approach relies on methodologies which select resources jointly based on a measure of cost effectiveness. HL&P uses this approach in its modeling activities to consider a variety of supply-side and demand-side resources simultaneously. HL&P considers two well-defined cost objectives, rate impact and total resource cost, which result in two possible mixes of supply-side and demand-side resources.

Staff relies on the sequential approach. This chapter presents the results of the staff analysis of end-use energy efficiency as a resource alternative. Staff has reviewed the utility goals and DSM program impacts to arrive at its recommendations. Consistent with the sequential approach, staff presents these demand-side resources as an adjustment to the peak demand and sales forecasts. The adjusted forecasts form the basis of the analysis of supply-side resources presented in Chapter Six.

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

Demand-side resources have unique characteristics that enhance and constrain their use within an electric utility resource plan. Risk and uncertainty have influenced the resource planning process to the extent that utilities are relying more on smaller, more flexible resources. A good resource plan is flexible enough to deal with a host of uncertainties. DSM programs represent an essential addition to resource plans because:

1. Implementation lead times can be relatively short.
2. Scale can be modest and adjustable.
3. Costs are controllable; large cost overruns are unlikely.
4. Changes in the rate of growth in sales can be automatically moderated to reduce uncertainty.

5. Large-scale failure is unlikely because failure can be detected and programs moderated.
6. Impact estimation is no more unreliable than many other data estimation functions required for long-term planning.

Demand-side programs can provide planning flexibility. Many programs, particularly passive demand-side programs, have short implementation lead times relative to some supply-side resource alternatives. Experienced utilities can initiate a new program within a matter of months, while less-experienced utilities can implement pilot programs within a year by replicating the successful DSM programs of other utilities. Further, the programs can be implemented on any scale, adding another aspect of flexibility in response to resource needs.

The scale of certain DSM programs automatically adjusts to moderate the impact of economic fluctuations on load growth. Programs targeted at new building efficiency will meet, exceed, or fall short of specified goals as the business cycle fluctuates. The market penetration will be highly correlated with economic growth. If growth is small, construction starts will be few and such programs will barely affect demand. In contrast, more rapid economic growth will result in greater participation and savings. In this manner, an effective set of DSM programs can moderate the risks asscoiated with uncertainty.

Electric utilities and reliability councils distinguish, as we have here, between the reliability of impact estimates for passive and active demand-side programs. There is uncertainty associated with active DSM because, although a customer may have a contractual agreement to cooperate, the contract is often short in duration and may not be renewed. Further, customers that take advantage of interruptible service during periods of surplus capacity may return to firm contracts when the frequency of interruptions increases.

Passive DSM is sometimes perceived as uncertain because planners do not consider the forecasts of program impacts reliable. This perception arises in part because efficiency gains cannot be measured in the manner that generating unit output is measured. However, the impact of thousands of efficient homes from thousands of DSM program participants is routinely measured and analyzed using statistical tools. Reliable DSM impact estimates are essential for a balanced consideration of demand-side resources. Effective evaluation includes and adjusts for customer behavior.

Summary of Demand-Side Adjustments

The staff, using the sequential method, prepares estimates of the impact of demand-side resources adjusting the unadjusted (raw) peak-demand and sales forecasts described in Chapter Three. These adjustments fall into three categories:

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

Exogenous factor adjustments include the effects of federal, state, and local regulations and customer actions beyond the control of the utility. Active and passive demand-side management (DSM) adjustments include the effects of utility-sponsored programs which are not reflected in the sales and peak demand forecasts.

During the review process, staff examines the adjustments to peak demand submitted by the utilities. These adjustments are accepted as submitted if they are documented and reasonable. Otherwise, an independent set of adjustments is prepared based on the program design and efficiency levels and the capabilities and intentions of the state's utilities.

Table 5.1 displays the adjustments made to the forecast on a statewide basis. Only the Texas portion of GSU, SPS, SWEPCO, and EPE are included in these tables. The peak demand adjustments are presented by category: passive DSM, active DSM, and exogenous factors. As will be explained more fully later, the peak demand forecasts include hundreds of megawatts of DSM which are embedded in the forecast. Passive DSM projections reflect only those activities which will add to the resource base, compared to that which is reflected in the unadjusted forecast. Passive DSM is expected to grow about 110 to 180 MW per year, reaching more than 2,500 MW by 2006. During the same period, active DSM is expected to increase from its current level of about 1,860 MW to more than 2,600 MW. The total of nearly 5,200 MW of DSM in Texas by 2006 (about 3,300 MW above current levels) represents a significant resource contribution.

Table 5.2 presents the energy adjustments by customer class. The energy adjustments are relatively small because most utilities focus on load management strategies, not the reduction of electricity consumption. Tables 5.3 and 5.4 show total system impacts including non-Texas portions of multi-jurisdictional utilities.

DSM Programs in Texas

Demand-side management programs have been offered in Texas since 1980. Table 5.5 provides a list of the historical DSM programs for the major utilities. The table is presented with the following categories of information:

1. Program name
2. Eligible customer class
3. The application (technology, device, or end-use)
4. The cumulative megawatt impact during the past decade
5. The cumulative MWH impact in 1991
6. The program operation dates

TABLE 5.1

DEMAND SIDE ADJUSTMENTS
TEXAS SYSTEMS
1992-2006
(MW)

Year	Exogenous	Active DSM	Passive DSM	Total
1992	7	(1,862)	(111)	(1,966)
1993	(19)	(1,995)	(228)	(2,242)
1994	(103)	(1,854)	(386)	(2,343)
1995	(169)	(2,022)	(573)	(2,765)
1996	(180)	(2,165)	(769)	(3,113)
1997	(229)	(2,252)	(989)	(3,471)
1998	(282)	(2,346)	(1,178)	(3,806)
1999	(285)	(2,438)	(1,382)	(4,104)
2000	(287)	(2,492)	(1,594)	(4,373)
2001	(289)	(2,535)	(1,806)	(4,630)
2002	(310)	(2,570)	(1,991)	(4,871)
2003	(309)	(2,591)	(2,167)	(5,067)
2004	(309)	(2,613)	(2,356)	(5,278)
2005	(308)	(2,634)	(2,543)	(5,484)
2006	(308)	(2,655)	(2,757)	(5,719)

TABLE 5.2

DEMAND SIDE ADJUSTMENTS
TEXAS SYSTEMS
1992-2006
(MWH)

Year	Residential	Commercial	Industrial	Wholesale	Total
1992	(90,003)	(102,327)	(103,761)	1,708,732	1,412,641
1993	(210,645)	(222,157)	(109,694)	2,266,271	1,723,775
1994	(335,479)	(406,547)	(125,779)	2,525,527	1,657,722
1995	(434,287)	(618,489)	(176,409)	2,725,486	1,496,301
1996	(529,853)	(848,180)	(205,790)	2,766,113	1,182,290
1997	(609,576)	(1,134,964)	(244,431)	2,790,180	801,209
1998	(694,665)	(1,414,738)	(284,335)	2,809,863	416,125
1999	(717,714)	(1,725,878)	(327,483)	2,831,309	60,234
2000	(729,380)	(2,063,816)	(370,080)	2,848,171	(315,105)
2001	(739,037)	(3,052,994)	(1,067,835)	2,859,836	(2,000,030)
2002	(788,040)	(3,380,154)	(1,099,980)	2,726,155	(2,542,019)
2003	(843,149)	(3,685,882)	(1,131,113)	2,766,086	(2,894,058)
2004	(901,006)	(3,980,256)	(1,161,683)	2,801,273	(3,241,672)
2005	(961,805)	(4,294,444)	(1,191,801)	2,848,875	(3,599,175)
2006	(1,026,069)	(4,613,066)	(1,223,164)	2,892,076	(3,970,223)

TABLE 5.3

DEMAND SIDE ADJUSTMENTS
TOTAL SYSTEMS
1992-2006
(MW)

Year	Exogenous	Active DSM	Passive DSM	Total
1992	(44)	(1,897)	(111)	(2,053)
1993	(82)	(2,031)	(228)	(2,340)
1994	(176)	(1,889)	(386)	(2,452)
1995	(264)	(2,058)	(573)	(2,894)
1996	(279)	(2,200)	(769)	(3,248)
1997	(333)	(2,288)	(989)	(3,610)
1998	(390)	(2,381)	(1,178)	(3,949)
1999	(393)	(2,473)	(1,382)	(4,248)
2000	(395)	(2,528)	(1,594)	(4,517)
2001	(397)	(2,585)	(1,806)	(4,788)
2002	(418)	(2,621)	(1,991)	(5,029)
2003	(417)	(2,641)	(2,167)	(5,225)
2004	(417)	(2,663)	(2,356)	(5,436)
2005	(416)	(2,684)	(2,543)	(5,643)
2006	(416)	(2,705)	(2,757)	(5,878)

TABLE 5.4

DEMAND SIDE ADJUSTMENTS
TOTAL SYSTEMS
1992-2006
(MWH)

Year	Residential	Commercial	Industrial	Wholesale	Total
1992	(99,377)	(108,160)	(216,009)	1,708,732	1,285,186
1993	(231,975)	(235,598)	(239,462)	2,266,271	1,559,236
1994	(368,765)	(427,645)	(257,737)	2,525,527	1,471,380
1995	(476,338)	(647,294)	(345,159)	2,725,486	1,256,695
1996	(580,666)	(884,745)	(374,540)	2,766,113	926,162
1997	(667,091)	(1,179,341)	(413,181)	2,790,180	530,567
1998	(758,883)	(1,466,981)	(453,085)	2,809,863	130,914
1999	(781,932)	(1,778,121)	(496,233)	2,831,309	(224,977)
2000	(793,598)	(2,116,059)	(538,830)	2,848,171	(600,316)
2001	(803,255)	(3,105,237)	(1,236,585)	2,859,836	(2,285,241)
2002	(852,258)	(3,432,397)	(1,268,730)	2,726,155	(2,827,230)
2003	(907,367)	(3,738,125)	(1,299,863)	2,766,086	(3,179,269)
2004	(965,224)	(4,032,499)	(1,330,433)	2,801,273	(3,526,883)
2005	(1,026,023)	(4,346,687)	(1,360,551)	2,848,875	(3,884,386)
2006	(1,090,287)	(4,665,309)	(1,391,914)	2,892,076	(4,255,434)

TABLE 5.5
DEMAND-SIDE MANAGEMENT PROGRAMS

Texas Utilities Elextric Company

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
EA Structure Program	Residential	Building envelope	(84)	(168,000)	1981-1987
EA Lighting Program	Commercial, Industrial	Efficient lighting equipment	0	(863,460)	1982-1990
New Nonresidential Heat Pump	Commercial, Industrial	Heat pump, air conditioner	(4)	(11)	1987-1991
Existing Nonresidential HVAC	Commercial, Industrial	Heat pump, air conditioner	(38)	(66,180)	1982-1991
EA New Single Family	Residential	Building envelope, heat pump, air conditioner (multi-fuel new homes)	(151)	(296,415)	1981-1991
EA New Multifamily	Residential	Building envelope, heat pump, air conditioner (multi-fuel new homes)	(85)	(308,845)	1981-1991
EA Existing Single Family	Residential	Heat pump, air conditioner	(162)	(231,526)	1981-1991
EA Existing Multifamily	Residential	Heat pump, air conditioner	(7)	(14,136)	1981-1991
EA Room Unit	All	Heat pump, air conditioner	(61)	(78,232)	1981-1991
EA Efficient Water Heating	All	water heater	(2)	(6,305)	1981-1991
EA Thermal Cool Storage	All	Commercial cool storage	(65)	0	1982-1991
EA On-Peak Load Shift	Nonresidential	load shifting	(149)	0	1991
EA On-Peak Efficiency Improvement	Industrial	Efficient equipment	(14)	(65,289)	1991
EA Off-Peak Lighting	All	lighting	NA	NA	1981-1991
Interruptible Rates	Industrial	Interruption of Service	(403)	0	1991
		Passive Programs	(822)	(2,098,399)	
		Promotional Activities	0	0	
		Net Passive	(822)	(2,098,399)	
		Active Programs	(403)	0	

Houston Lighting and Power Company

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Commercial Electric Chiller	Commercial	Cooling systems	20	69,966	1988-1989
Economic Development	Commercial, Industrial	Various industrial applications	228	1,134,799	1988-1990
New Construction Incentive	Residential	HVAC	(45)	(71,881)	1982-1985
Weatherization Rebate	Residential	Building envelope	(1)	(4,704)	1983-1986
Commercial Cooking	Commercial	cooking equipment	1	3,021	1989
COMQUEST	Commercial	Energy audits	(1)	(7,688)	1986-1987
Industrial Motor	Industrial	electric motors	42	349	1989-1990
Large Commercial Air Cond. Control	Commercial	air conditioning	0	0	1984-1987
Commercial Electric Heating	Commercial	heating	0	365	1989-1990
Good Cents Home (1988-1990)	Residential	Building envelope, heat pump, air conditioner	2	(2,408)	1988-1990
Heat Pump	Residential, Commercial	Heat pump	(2)	196	1988-1990
High Efficiency Bonus	Residential	air conditioners, heat pumps	(102)	(109,640)	1982-1985
Heat Pump Bonus (New Construction)	Residential	Heat pump	0	(131)	1986
Business Audit	Commercial, Industrial	Energy audit	(29)	(150,154)	1982-1987
Heat Pump Bonus (Retrofit)	Residential	Heat pump	(1)	(579)	1986
Residential Security Lighting	Residential	Security lighting	0	831	1988-1991
Good Cents New Home	Residential	Building envelope, heat pump, air conditioner (multi-fuel new homes)	(3)	(1,456)	1991
Energy Efficiency HVAC	Residential	air conditioner, heat pump	(3)	901	1991
Good Cents Apartment	Residential	Building envelope, heat pump, air conditioner	(1)	(3,422)	1990-1991
Energy Efficient HVAC	Residential	air conditioner, heat pump	0	(687)	1991
Energy Check-up	Residential	Energy audit	0	(872)	1989-1991

HL&P (Cont'd)

Program Name	Class	Application	Cumulative MW Impact	Cumulative Impact	Program Dates
Energy Efficient HVAC (Retrofit)	Residential	air conditioner, heat pump	(3)	(8,951)	1991
Contract Lighting Service	all	Security/area efficient lighting	0	6,817	1987
Commercial Efficiency Improvement	Commercial	Building envelope, lighting	(1)	(5,579)	1991
Commercial Cool Storage	Commercial, Industrial	cool storage	(4)	1,532	1990
Interruptible Service	Industrial	Interruption of Service	(693)	0	1983-1991
Time of Day Residential Service	Residential	Load Shifting	0	(598)	1981-1991
		Passive Programs	(196)	(363,116)	
		Promotional Programs	292	1,213,740	
		Net Passive	96	850,624	
		Active Programs	(693)	(598)	

Gulf States Utilities Company

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Texas Tune Up	Residential	Air conditioner tune up	0	(2,047)	1985
Water Heater Wrap Up	Residential	Water heater wraps	0	(2,247)	1985
Weatherization	Residential	Weatherization for low-income customers	0	(86)	1985
High Efficiency Equipment Rebates	Residential	Heat pump, water heater	(1)	(84,075)	1985-1987
Existing Home Energy Audits	Residential	Energy audit	0	(20,313)	1985
N.E.W. 100+ and Bonus Homes	Residential	Building envelope, heat pump, air conditioner	(1)	(15,476)	1985
Commercial Energy Management Assistance	Commercial	Energy audit	0	(1,662)	1985
Good Cents Homes	Residential	Building envelope, heat pump, air conditioner, electric furnace (all-electric new homes)	(1)	(7,106)	1987-1991

GSU (Cont'd)

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Centsable Heating	Residential	Heat pump	(1)	(8,353)	1985-1991
Centsable Water Heating	Residential	Water heater	1	23,478	1990-1991
Centsable Leased Lighting	All	Outdoor lighting	0	9,673	1983-1991
Centsable Retail Lighting	Residential	Outdoor lighting	0	(149)	1989-1991
Centsable Commercial AC	Commercial	Air conditioner, heat pump	0	(498)	1991
Centsable Commercial Equipment	Commercial	Water heater, cooking equipment	3	18,731	1991
Interruptible Service-Metal Melting	Industrial	Interruption of service	(31)	0	1985-1991
Interruptible Service	Commercial, Industrial	Interruption of service	(107)	0	1981-1991
		Passive Programs	(5)	(141,365)	
		Promotional Programs	4	51,235	
		Net Passive	(1)	(90,130)	
		Active Programs	(138)	0	

Central Power and Light Company

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Heat Pump Incentive	Residential	Heat pump	(5)	(11,344)	1986-1990
Residential A/C Checkup	Residential	Air conditioner	(1)	(1,344)	1991
Good Cents	Residential	Building envelope, heat pump (new all-electric homes)	(12)	(23,375)	1983-1991
Centsable	Residential	Building envelope	(5)	(9,916)	1986-1991
Commercial Cooking	Commercial	Range	1	2,603	1991
Efficient Electrotechnologies	Commercial, Industrial	electrotechnologies	2	10,168	1991
Outdoor Lighting	Commercial	lighting	0	0	1987
HVAC and Lighting Audits	Commercial	energy audit	(2)	(6,216)	1986-1991
Better Thermal Utilization	Commercial, Industrial	energy audit	0	0	1988-1991
Commercial Heating	Commercial (Schools)	Heat pump	(13)	(19,898)	1990-1991

CPL (Cont'd)

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Irrigation District	Irrigation	Pumping	0	0	1990-1991
High Efficiency AC Incentive	Residential	Air conditioner	0	(827)	1991
Interruptible Service					
ISI	Industrial	Interruption of service	0	0	1991
ISPS	Industrial	Interruption of service	(5)	0	1991
ISA	Industrial	Interruption of service	(11)	0	1991
ISB	Industrial	Interruption of service	(351)	0	1991
		Passive Programs	(37)	(72,920)	
		Promotional Programs	3	12,771	
		Net Passive	(34)	(60,149)	
		Active Programs	(367)	0	

City Public Service Board of San Antonio

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Home Energy Improvement Loan Program	Residential	Building envelope, AC, etc.	NA	NA	1983-1991
Appliance Efficiency Incentive Program	Residential	Appliance efficiency	NA	NA	1983-1990
Interruptible Service	Industrial	Interruption of service	NA	NA	1991
Time of Day Service	Industrial	Load shifting	NA	NA	1991

Southwestern Public Service Company

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Dual Fuel Heat Pump	Residential	Heat pump	(8)	47,738	1982-1991
Energy Efficient Home Program	Residential	Building envelope, heat pump, electric furnace (new all-electric)	(7)	87,383	1976-1991
Electric Heat Pump	Residential	Heat pump	(3)	21,554	1987-1991
New Commercial Design Assistance	General Service	Building envelope	0	0	1990-1991

SPS (Cont'd)

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Residential Energy Audit	Residential	Building envelope, misc. measures	0	(146)	1989-1991
Add-on Heat Pump	Residential	Heat pump	0	(299)	1982-1991
Residential Security Lighting	Residential	Outdoor lighting	0	161	1990-1991
Leased Lighting	Commercial/ Industrial	Outdoor lighting	0	244	1991
Irrigation Sched. Load Management	Wholesale	Load scheduling	0	0	1990-1991
Interruptible Irrigation Program	Wholesale	Load shifting	0	0	1990-1991
Experimental Interruptible	Commercial	Interruption of service	(5)	0	1988-1991
CRMWA Interruptible	Municipal	Interruption of service	(18)	0	1991
Wholesale Interruptible	Wholesale	Interruption of service	(130)	0	1984-1991
		Passive Programs	(17)	156,231	
		Promotional Programs	0	405	
		Net Passive	(17)	156,635	
		Active Programs	(153)	0	

Southwestern Electric Power Company

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Improved Energy Efficient Home	Residential	Building envelope (all-electric new home)	(2)	(5,022)	1976-1991
Residential Conservation Service	Residential	Energy audit	NA	NA	1982-1984, 1988-1990
QUEST	Residential	Building envelope, misc. measures	NA	NA	1985-1987
Existing Home Heat Pump Replacement	Residential	Heat pump	0	(72)	1989-1991

SWEPCO (Cont'd)

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Interruptible Service	Industrial	Interruption of Service	(60)	NA	1984-1991
		Passive Programs	(2)	(5,094)	
		Promotional Programs	0	0	
		Net Passive	(2)	(5,094)	
		Active Programs	(60)	NA	

Lower Colorado River Authority

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Good Cents Home	Residential	Building envelope, air conditioner (multi-fuel new homes)	0	(2,916)	1986-1991
AC/Water Heater Cycling	Residential, Commercial	Air conditioner, heat pump, water heater cycling	(22)	0	1987-1991
Commercial Lighting Rebate	Commercial, Municipal	lighting	(2)	(5,498)	1987-1991
Commercial Load Control	Commercial, Municipal	energy system load control	(1)	0	1991
Commercial/Municipal Efficiency	Commercial, Municipal	Municipal and public buildings	(1)	(1)	1991
Energy Fitness	Residential, Commercial	Improved thermal envelopes, HVAC equipment	0	(267)	1990-1991
Cooling Efficiency	Residential, Commercial	Heat pump, air conditioner	(35)	(49)	1983-1991
		Passive Programs	(61)	(8,732)	

City of Austin*

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Residential Loan	Residential	Building envelope, HVAC	(18)	NA	1983-1991
Whole House	Residential	Building envelope, HVAC	(6)	NA	1986-1991
New Home Efficiency Rating	Residential	Building envelope, HVAC	(2)	NA	1985-1991
Residential Appliance Efficiency	Residential	Air conditioner, heat pump water heater	(64)	NA	1982-1991

COA (Cont'd)

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Multi-Family	Residential	Building envelope, HVAC	(8)	NA	1990-1991
Direct Weatherization	Residential	Building envelope	(4)	NA	1982-1991
Commercial Appliance Efficiency	Commercial	Air conditioner, heat pump	(12)	NA	1982-1991
Commercial Energy Management	Commercial	Lighting, building envelope, HVAC	(22)	NA	1986-1991
New Construction Commercial	Commercial	Lighting, building envelope, HVAC	(2)	NA	1988-1991
Thermal Energy Storage	Commercial	Cool storage	0	NA	1989-1991
ElectriCredit	Residential	Appliance cycling	(5)	NA	1985-1991
Municipal	Municipal	Building envelope, HVAC, lighting	(2)	NA	1983-1991
Audits	Residential	Energy audits	(1)	NA	1982-1991
*Data is through FY 1990					
		Passive Programs	(140)	NA	
		Active Programs	(5)	NA	

West Texas Utilities Company

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Residential Conservation Service	Residential	Energy audit	(1)	922	1982-1989
Residential Window Air Conditioner	Residential	air conditioner	(4)	(4,499)	1983-1990
Commercial, Room Air Conditioner	Commercial	air conditioner	0	(195)	1987-1990
ESP - Residential	Residential	Building envelope, air conditioner heat pump, solar or heat recovery water heating (multi-fuel new)	(16)	(17,971)	1983-1991
Quick Energy Savings Test	Residential	Building envelope, misc. measures	(3)	(2,306)	1985-1191
ESP - Commercial	Commercial, Industrial	Building envelope, HVAC	(5)	(7,928)	1987-1991
Commercial Audit	Commercial	Building envelope, HVAC	(1)	(1,083)	1983-1991
Industrial Energy Audits	Industrial	Various	(4)	(23,915)	1984-1991
		Passive Programs	(33)	(56,975)	

El Paso Electric Company

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Commercial Cooking	Commercial	Cooking equipment	1	0	1987-1988
New Apartment Construction	Residential	Heat pumps, insulation, etc.	0	0	1985-1988
Builder Installation Allowances	Residential	Water heating, HVAC, etc.	NA	NA	1986-1988
Small C/I Installation Allowance	Commercial	Water heating, heating, etc.	(1)	0	1986-1988
Thermal Energy Storage	Commercial	Cool storage	(1)	0	1987-1991
Commercial/Industrial Audit	Commercial, Industrial	Energy audit	(1)	(8,689)	1988-1991
School Efficiency	Commercial, (Schools)	HVAC, lighting	(1)	(1,196)	1990-1991
Residential Audits	Residential	Energy audit	0	(90)	1989-1991
Low Income Weatherization	Residential	Building envelope	0	(29)	1990-1991
		Passive Programs	(3)	(10,003)	
		Promotional Programs	0	0	
		Net Passive	(3)	(10,003)	

Texas-New Mexico Power Company

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Energy Checked Efficiency Home Program (ECEH)	Residential	Building envelope, heat pump, air conditioner (electric homes)	(9)	(34,962)	1975-1989
Good Cents Home	Residential	Building envelope, heat pump, air conditioner (mult-fule new homes)	0	(193)	1990-1991
High Efficiency AC and Heat Pump	Residential, Commercial	Heat Pump, air conditioner	0	(339)	1990-1991
Interruptible Irrigation	Agricultural	Load Shifting	(2)	0	1983-1991

TNP (Cont'd)

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
High Pressure Sodium	Lighting	Lighting	8	(840)	1990-1991
		Passive Programs	(1)	(36,334)	
		Active Progrmas	(2)	0	

Brazos Electric Power Cooperative, Inc.

Program Name	Class	Application	Cumulative MW Impact	Cumulative MWH Impact	Program Dates
Centsable Cooling	Residential	Air conditioner	0	2	1991
		Promotional Program	0	2	
		Total Passive Programs	(1,318)	(2,636,707)	
		Total Promotional Programs	299	1,278,152	
		Total Net Passive	(1,019)	(1,358,555)	
		Total Active Programs	(1,820)	(598)	

Based on utility-reported data, the impact of DSM programs from 1980 through 1991 resulted in a peak-demand reduction of 1,338 MW from passive DSM and 1,820 MW through active DSM. The total promotional program impact (predominantly HL&P's economic development activities) increased peak by 299 MW during the same period. Energy usage was reduced by 3,486,687 MWH for passive DSM, while promotional programs increased usage by 1,278,152 MWH.

Figure 5.1 illustrates the utility-reported cost of DSM programs during the past decade. (Note that these data are for illustrative purposes. Reporting by utilities is not uniform.) These DSM expenditures are provided in two categories: 1) incentive payments to customers; and 2) other program expenses.

Each current and projected DSM program is listed in Table 5.6. This list provides the following categories of information:

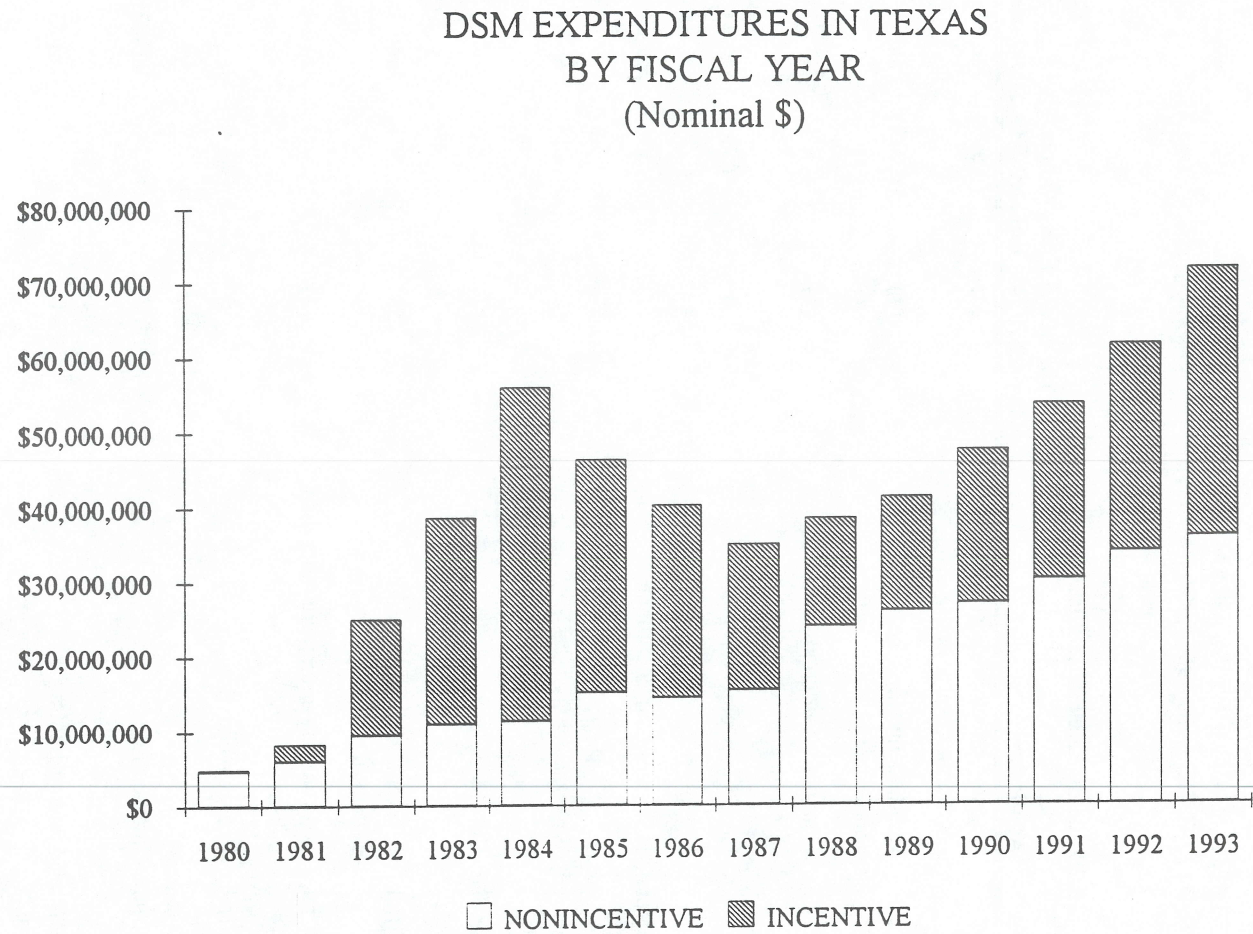
1. Program name
2. Eligible customer class
3. The application (technology, device, or end-use)
4. The cumulative megawatt impact from 1992-1994
5. The cumulative MWH impact in 1994
6. The date the program was initiated
7. The program status

The cumulative three-year impacts are provided to give a sense of the relative scale of programs. Program descriptions and more detailed data on past achievements, historic costs, projected participation, program technologies and efficiencies, and estimated impact per participant are provided in each utilities' energy efficiency plan.

Recommended Exogenous Factor Adjustments

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

FIGURE 5.1



Note: These expenditures include both the cost of conservation and promotional programs. Caution must therefore be exercized in relating these costs to the average cost of a saved kilowatt or kilowatt-hour. Projected data are used for 1992 and 1993. This figure is representative of the total DSM expenditures but it is incomplete. Several utilities did not report DSM cost data for 1980-83.

TABLE 5.6
DEMAND-SIDE MANAGEMENT PROGRAMS IN TEXAS
PROGRAM LISTING AND 1992-1994 INPACTS

Texas Utilities Elextric Company

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Energy Action New Single-Family	Residential	Building envelope, heat pump, air conditioner, water heater	(3)	(9,309)	Jan-81	Full Scale
Energy Action New Multi-Family	Residential	Building envelope, heat pump, air conditioner	(1)	(4,015)	Jan-81	Full Scale
Energy Action Existing Single-Family	Residential	Heat pump, air conditioner, Ceiling Insulation	(7)	(11,371)	Jan-81	Full Scale
Energy Action Existing Multi-Family	Residential	Heat pump, air conditioner, Ceiling Insulation	0	(586)	Jan-81	Full Scale
Energy Action Room Unit	Residential, Commercial, Industrial	Heat pump, air conditioner	(1)	(886)	Jan-81	Full Scale
Energy Action Efficient Water Heating	Residential, Commercial, Industrial, Municipal	Water heater	0	(888)	Jan-81	Full Scale
Energy Action Thermal Cool Storage	Residential, Commercial, Industrial, Municipal	Cool storage	(17)	0	Jan-82	Full Scale
Energy Action On-Peak Efficeincy Improvement	Commercial, Industrial, Municipal	Efficient equipment, building structural measures	(57)	(255,567)	Jan-91	Full Scale
Energy Action On-Peak Load Shift	Commercial, Industrial, Municipal	Load shifting equipment other than thermal energy storage	(42)	0	Jan-84	Proposed
Energy Action Commercial Audit	Commercial, Industrial, Municipal	Energy Audit	0	0	Jan-92	Full Scale
Energy Action Commercial Audit	Commercial, Industrial	Interruptible	(466)	0	Jan-83	Full Scale
Energy Action Commercial Audit	Residential, Commercial, Industrial, Municipal	Outdoor lighting	0	0	Jan-81	Full Scale

TU Electric (Cont'd)

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Other Passive Programs	Commercial, Industrial	Other	(48)	(95,785)	NA	Full Scale
Geothermal Heat Pump	Residential	Heat pump	(1)	(2,665)	Jan-88	Full Scale

Houston Lighting and Power Company

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Geothermal Heat Pump	Residential	Building envelope	(4)	(2,621)	Jan-91	Full Scale
Energy Efficient HVAC-Good Cents New Home	Residential	Heat pump,air conditioner	(2)	(6,951)	Jan-91	Full Scale
Geothermal Apartment	Residential	Building envelope	(1)	(1,531)	Oct-90	Full Scale
Energy Efficient HVAC-Good Cents Apartment	Residential	Heat pump,air conditioner	(2)	(6,951)	Jan-91	Full Scale
Energy Check-up	Residential	Energy audit	(1)	(3,778)	Jul-89	Full Scale
Energy Efficient HVAC - Retrofit	Residential	Heat pump,air conditioner	(15)	(28,690)	Jan-91	Full Scale
Contract Lighting Service	Residential, Commercial, Industrial	Security/area efficient lighting	0	14,531	Jun-87	Full Scale
Commercial Efficiency Improvement	Commercial	Various peak reducing technologies	(13)	(46,995)	Sep-91	Full Scale
Commercial Cool Storage	Commercial,, Industrial	Cool storage	(33)	12,669	Jan-90	Full Scale
Residential Direct Control	Residential	Heat pump, air conditioner	(70)	151	1992	Pilot
Good Cents Improved Home	Residential	Building envelope	(2)	(3,795)	Feb-92	Pilot
Industrial Efficiency Improvement Program	Industrial	Motors, variable speed drives, lighting, other efficient technologies, energy audit.	(35)	(6,466)	Jan-92	Pilot
Interruptible Rates	Commercial, Industrial	Interruptible services: 30 minutes, 10 minutes and instantaneous	(655)	0	Jan-67	Full Scale

Gulf States Utilities Company

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Good Cents Home	Residential	Building envelope, heat pump, air conditioner, electric furnace	0	0	Jan-87	Full Scale
Centsable Heating	Residential	Heat Pump	0	0	Jan-85	Full Scale
Centsable Water Heating	Residential	Water heater	0	0	Mar-90	Full Scale
Centsable Leased Lighting	All classes	Outdoor lighting	0	0	Jan-83	Full Scale
Centsable Retail Lighting	Residential	Outdoor lighting	0	0	Jan-89	Full Scale
Centsable Commercial Air Conditioning	Commercial	Heat pump, air conditioners	0	0	Jan-91	Full Scale
Centsable Commercial Equipment	Commercial	Water heater, range	0	0	Jan-91	Full Scale
Industrial Rates	Industrial	Interruptible service	0	0	1979	Full Scale

Central Power and Light Company

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Residential High Efficiency Air Conditioning Incentive Program	Residential	Heat pump, air conditioner	0	(3,010)	Jan-91	Full Scale
Air Conditioning Check-Up	Residential	Air conditioner maintenance	(3)	(8,323)	Mar-91	Full Scale
Good Cents	Residential	Building envelope, heat pump, air conditioner, water heater	(7)	(15,101)	Jun-83	Full Scale
Centsable	Residential	Building envelope, heat pump, air conditioner, water heater	(6)	(10,677)	1986	Full Scale
Commercial Cooking	Commercial	Range	0	0	Jan-91	Full Scale
Efficient Electrotechnologies	Commercial, Small Industrial	Industrial process	7	39,215	Jan-91	Full Scale
Commercial Outdoor Lighting	All	Outdoor lighting	0	0	Jan-92	Full Scale
Commercial Unitary HVAC Program	Commercial, Industrial	Heat pump, air conditioner, resistance heat	(2)	(3,653)	Jan-92	Full Scale

CPL (Cont'd)

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Quest	Residential	Energy audit	0	0	Apr-92	Design stage
Thermal Energy Storage	Commercial, Small Industrial	Thermal energy storage systems	(5)	0	Apr-92	Pilot
High Efficiency Chiller	Commercial, Small Industrial	Chillers	(4)	(11,137)	Apr-92	Pilot
Interruptible Load	Industrial	Interruption	(338)	0	NA	Full Scale

City Public Service of San Antonio

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Interruptible Load	Industrial	Interruption	(10)	0	NA	Full Scale

Southwestern Public Service Company

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Residential	Residential	Building envelope, misc. measures	0	(82)	Jul-89	Full Scale
Energy Efficient Home	Residential	Building envelope, heat pump, electric furnace	0	27,249	Jan-76	Full Scale
Dual Fuel Heat Pump	Residential	Heat pump with gas back-up in replacement of AC with gas heat	0	42,379	Jan-82	Full Scale
Add-On Heat Pump	Residential	Heat pump in replacement of electric furnace	0	42,379	Aug-82	Full Scale
Electric Heat Pump	Residential	Heat pump in fuel switching applications	0	11,365	1987	Full Scale
Residential Security Lighting	Residential	Outdoor lighting	0	235	Jan-90	Full Scale
New Commercial Design Assistance	Commercial	Building envelope	0	235	Mar-90	Full Scale
Leased Lighting	Commercial, Industrial	Outdoor lighting	0	791	1991	Full Scale

SPS (Cont'd)

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Canadian River Municipal Water Authority Interruptible	Municipal	Interruption	(11)	0	1962	Full Scale
Interruptible Irrigation Loads	Wholesale (retail agric.)	Interruption	(40)	0	Jan-90	Full Scale
Experimental Interruptible	Industrial (metal melting)	Large industrial	(3)	0	Sep-88	Full Scale
Other Passive Programs	Commercial	Commercial	0	(182)	NA	Full Scale

Southwestern Electric Power Company

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Existing Home Heat Pump Replacement	Residential	Heat pump replacement of AC with gas heat	0	0	Jan-89	Full Scale
Good Cents New Home	Residential	Building envelope, heat pump, air conditioner, water heater	0	0	Jan-92	Pilot
High Efficiency Water Heater	Residential	Water pump	0	0	1992	Pilot
New Multi-Family Home Heat Pump	Residential	Heat pump	0	0	1992	Pilot
Existing Home Air Conditioner Replacement	Residential	Air Conditioner	0	0	Jan-92	Pilot
Interruptible Power Service	Industrial	Interruptible service	(58)	0	Feb-84	Full Scale
Off-Peak Service Rider	LP, LLP, MMS (1)	Interruptible service	0	0	Jul-87	Full Scale

Lower Colorado River Authority

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Good Cents Home	Residential	Building envelope, heat pump, air conditioner	(2)	(2,320)	May-86	Full Scale

(1) - LP - Lighting & Power Service, LPP - Large Lightng & Power Service, MMS - Metal Melting Service - Distribution Voltages

LCRA (Cont'd)

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Air Conditioner Cycling	Residential, Small Commercial	Heat pump, air conditioner	(17)	0	1997	Full Scale
Water Heater Cycling	Residential, Small Commercial	Water heater cycling	(6)	0	1997	Full Scale
Commercial Lighting Rebate	Comm., Municipal, Public Schools	Lighting	(1)	(1,890)	1997	Full Scale
Commercial Load Control	Comm., Industrial, Municipal	HVAC, water heating, motors, refrigeration	(6)	0	1991	Pilot
Commercial Municipal Efficiency	Municipal, Public Buildings	Lighting, HVAC, water heating, elec. range, refrigeration, motors	0	0	1991	Pilot
Energy Fitness	Residential	Building envelope, HVAC, water heating	(2)	(1,478)	1990	Full Scale
Cooling Efficiency	Residential, Small Commercial	Heat pump, air conditioner	(4)	(5,100)	Sep-83	Full Scale

City of Austin Electric Utility

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Resident Audit	Residential	Energy Audit	0	0	1982	Full Scale
Home Energy Loan	Residential	Building envelope, HVAC	(8)	(21,805)	1983	Full Scale
Whole House Rebate	Residential	Building envelope, HVAC	(13)	(40,719)	Jun-86	Full Scale
Multi-Family Incentive	Residential	Building envelope, HVAC, lighting	0	0	Aug-89	Full Scale
Energy Star Rating	Residential	Building envelope, HVAC, lighting water heater	0	0	1984	Full Scale
Green Builder	Residential	"Earth friendly" and energy-conserving building materials, and home appliances	0	0	1992	Pilot

COA (Cont'd)

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Appliance Efficiency Program	Residential, Commercial	Air conditioner/heat pump under 7.5 tons, water heater	(15)	(34,087)	1982	Full Scale
Direct Weatherization	Residential	Building envelope, minor repair	0	0	1983	Full Scale
Existing Commercial Program	Commercial	Lighting, building envelope, HVAC, motors	(21)	(88,052)	Sep-86	Full Scale
New Construction Commercial	Comm., Industrial	Lighting, building envelope, HVAC, motors	0	0	Jun-88	Full Scale
Large Customer Assistance	Comm., Industrial	Lighting, building envelope, HVAC, motors, ASD, EMS, VAV	0	0	1990	Full Scale
Thermal Energy Storage	Commercial	Cool storage	(2)	(5)	1988	Full Scale
ElectriCredit	Residential	Air conditioner, heat pump cycling	(8)	0	1985	Full Scale

West Texas Utility Company

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Energy Savings Plan - Residential	Residential	Building envelope, AC, HP, solar or heat recovery water heating	(2)	716	Jan-83	Full Scale
QUEST (audit)	Residential	Energy audit	0	(1,172)	Apr-85	Full Scale
Energy Savings Plan - Commercial	Comm.,Industrial	Building envelope, HVAC	0	0	Jan-87	Full Scale
Commercial Audit	Commercial	Energy audit	0	0	Jan-83	Full Scale
Industrial Energy Audit	Industrial	All electric equipment	(2)	(19,896)	1984	Full Scale
Energy Saving Plan - Res. Electric Water Heater with Time Clock	Residential	Water heater	0	0	Jan-92	Pilot
Commercial Leased Lighting	Comm.,Industrial	Outdoor Lighting	0	3,199	Jan-92	Pilot

El Paso Electric Company

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Thermal Energy Storage	Commercial	Col storage	(1)	0	Mar-87	Full Scale
Commercial/Industrial Audit	Commercial, Industrial	Energy audit	(3)	(5,871)	Jul-88	Full Scale
School Efficiency	School Districts	Lighting controls	0	0	Jan-90	Full Scale
Residential Audit	Residential	Energy audit	0	0	Jun-89	Full Scale
Low Income Weatherization	Residential	Building envelope	0	0	Sep-90	Full Scale

Texas-New Mexico Power Company

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Good Cents Home	Residential	Building envelope, heat pump, air conditioner	(3)	(1,635)	Jul-90	Full Scale
High Efficiency Air Conditioner and Heat Pump	Residential	Heat pump, air conditioner	(3)	(3,525)	Jul-90	Full Scale
Interruptible Irrigation	Agricultural	Load shifting	0	0	1983	Full Scale

Brazos Electric Power Cooperative

Program Name	Class	Application	Peak MW Impact 1994	Energy Impact 1994 MWH	Start Dates	Status
Centsible Cooling	Residential	Air conditioner, heat pump	(2)	(1,966)	1991	Full Scale
Centsible Water Heater	Residential	Water heater	0	0	Apr-92	Pilot
Centsible New Home Construction	Residential	Building envelope	0	0	1993	Design

The statewide impact of the National Appliance Energy Conservation Act of 1987 was estimated by staff in 1989 using the Residential End-Use Energy Planning System (REEPS). REEPS is well suited to consider the impact of appliance efficiency standards. The REEPS model explicitly considers end-use fuel, appliance type, and efficiency choice in new and replacement purchase decisions. Staff allocated the statewide estimate to the 13 major service areas using the ratio of service area residential appliance electricity consumption to statewide appliance consumption. Coincident-peak load factors were then applied to calculate the coincident-peak demand impact in megawatts from the sales impact. The adjustments for each service area are presented in Tables 5.7 and 5.8.

Customer growth and new industrial plant openings were a mainstay of the Texas economy in the 1970s and early 1980s. During the late 1980s, self-generation by industrial customers increased in Texas. The effects of self-generation and industrial growth are reflected in the historic data (for example, in historical sales to these customers and nonagricultural employment variables) used to prepare the staff's sales and peak demand forecasts. Staff believes that its forecasting models are sufficiently robust to account for both future self-generation and exceptional industrial load growth; therefore, no adjustments were made for these factors.

Firm standby customer contracts total 905 MW in the Texas portion of four generating utilities: HL&P, GSU, CPL, and TNP. Generally, these are contracts with customers who self-generate, but receive power on a stand-by basis when they experience an outage on their generators. Power demanded by standby customers must be available on the system; thus it is reasonable that utilities add a portion of standby contracts to their capacity planning requirements. Based on the probability of simultaneous outages of standby customers, staff has adjusted the forecast by about 12 percent of the total amount of contracted standby capacity.

Recommended Demand-Side Management Adjustments

Tables 5.9 to 5.42 summarize the demand-side adjustments for each utility service area. The peak-demand adjustments are presented by category: passive DSM, active DSM, and exogenous factors. The energy adjustments are presented by customer class.

TABLE 5.7

PEAK DEMAND IMPACTS OF THE NAECA
AT THE POINT OF GENERATION
1992-2001

Year	TU	HL&P	GSU-Texas	GSU-Total	CPL	CPS
1992	(21)	(7)	(1)	(3)	(3)	(2)
1993	(43)	(14)	(2)	(6)	(6)	(7)
1994	(81)	(25)	(5)	(10)	(11)	(11)
1995	(119)	(37)	(7)	(15)	(16)	(14)
1996	(148)	(45)	(9)	(19)	(20)	(18)
1997	(176)	(54)	(11)	(22)	(24)	(20)
1998	(201)	(61)	(12)	(25)	(27)	(23)
1999	(226)	(69)	(14)	(28)	(30)	(23)
2000	(226)	(69)	(14)	(28)	(30)	(23)
2001	(226)	(69)	(14)	(28)	(30)	(23)

Year	SPS-Texas	SPS-Total	SWEPCO-Texas	SWEPCO-Total	LCRA	COA
1992	(1)	(1)	(1)	(2)	(3)	0
1993	(1)	(2)	(2)	(4)	(5)	0
1994	(3)	(4)	(3)	(8)	(9)	0
1995	(4)	(6)	(5)	(11)	(13)	0
1996	(5)	(8)	(6)	(14)	(16)	0
1997	(6)	(9)	(7)	(16)	(20)	0
1998	(7)	(10)	(8)	(19)	(22)	0
1999	(8)	(11)	(9)	(21)	(25)	0
2000	(8)	(11)	(9)	(21)	(25)	0
2001	(8)	(11)	(9)	(21)	(25)	0

Year	WTU	EPE-Texas	EPE-Total	TNP	BEPC	Texas Total
1992	(1)	0	(1)	(1)	(1)	(42)
1993	(2)	(1)	(2)	(3)	(3)	(89)
1994	(4)	(1)	(2)	(5)	(5)	(163)
1995	(6)	(2)	(3)	(7)	(6)	(236)
1996	(7)	(3)	(4)	(9)	(8)	(294)
1997	(9)	(3)	(5)	(10)	(9)	(349)
1998	(10)	(3)	(5)	(12)	(11)	(397)
1999	(11)	(4)	(6)	(13)	(12)	(444)
2000	(11)	(4)	(6)	(13)	(12)	(444)
2001	(11)	(4)	(6)	(13)	(12)	(444)

TABLE 5.8

MWH IMPACTS OF THE NAECA
AT THE CUSTOMER METER
1992-2001

Year	TU	HL&P	GSU-Texas	GSU-Total	CPL	CPS
1992	(33,751)	(15,331)	(3,131)	(6,294)	(6,482)	(5,784)
1993	(67,502)	(30,662)	(6,262)	(12,587)	(12,964)	(13,570)
1994	(114,701)	(51,134)	(10,379)	(20,862)	(21,521)	(21,356)
1995	(161,899)	(71,606)	(14,496)	(29,137)	(30,077)	(27,091)
1996	(196,782)	(86,675)	(17,522)	(35,219)	(36,369)	(32,827)
1997	(231,665)	(101,744)	(20,548)	(41,301)	(42,660)	(37,331)
1998	(259,534)	(113,532)	(22,898)	(46,024)	(47,554)	(41,835)
1999	(287,403)	(125,319)	(25,247)	(50,746)	(52,449)	(41,835)
2000	(287,403)	(125,319)	(25,247)	(50,746)	(52,449)	(41,835)
2001	(287,403)	(125,319)	(25,247)	(50,746)	(52,449)	(41,835)

Year	SPS-Texas	SPS-Total	SWEPCO-Texas	SWEPCO-Total	LCRA	COA
1992	(1,853)	(2,564)	(1,487)	(3,665)	(4,308)	0
1993	(3,705)	(5,129)	(2,974)	(7,331)	(8,617)	0
1994	(5,641)	(7,807)	(4,882)	(12,035)	(13,961)	0
1995	(7,577)	(10,486)	(6,791)	(16,738)	(19,305)	0
1996	(8,965)	(12,408)	(8,190)	(20,188)	(23,212)	0
1997	(10,354)	(14,330)	(9,590)	(23,637)	(27,118)	0
1998	(11,294)	(15,630)	(10,663)	(26,283)	(30,063)	0
1999	(12,233)	(16,930)	(11,737)	(28,929)	(33,007)	0
2000	(12,233)	(16,930)	(11,737)	(28,929)	(33,007)	0
2001	(12,233)	(16,930)	(11,737)	(28,929)	(33,007)	0

Year	WTU	EPE-Texas	EPE-Total	TNP	BEPC	Texas Total
1992	(1,823)	(1,154)	(1,493)	(2,087)	(2,021)	(79,212)
1993	(3,646)	(2,307)	(2,985)	(4,175)	(4,043)	(160,427)
1994	(6,075)	(3,348)	(4,331)	(7,043)	(6,558)	(266,599)
1995	(8,504)	(4,389)	(5,677)	(9,912)	(9,073)	(370,720)
1996	(10,292)	(5,121)	(6,625)	(12,029)	(10,912)	(448,896)
1997	(12,079)	(5,854)	(7,572)	(14,145)	(12,751)	(525,839)
1998	(13,476)	(6,290)	(8,137)	(15,823)	(14,139)	(587,101)
1999	(14,873)	(6,727)	(8,702)	(17,501)	(15,527)	(643,858)
2000	(14,873)	(6,727)	(8,702)	(17,501)	(15,527)	(643,858)
2001	(14,873)	(6,727)	(8,702)	(17,501)	(15,527)	(643,858)

As indicated in past reports, Commission staff has conducted an independent program-by-program review to develop its DSM projections. The purpose of the review is to establish an estimate of the impact of the DSM activities not reflected in the staff's sales and peak demand forecast. These demand-side adjustments represent the likely impact of demand-side management programs based on the present capabilities and intentions of the utilities. In a few instances, the impact of future, undefined programs were adopted in recognition of the potential for additional DSM.

The Statewide Potential For Demand-Side Energy Efficiency

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

1. COA contracted for a technical potential study and a technical audit of its DSM programs in 1986-1987.
2. LCRA contracted for an estimate of conservation and load management potential in 1988-1989.
3. HL&P contracted for studies of DSM potential in 1989-1990, including industrial efficiency and electrification.

Several EPRI studies have attempted to estimate the energy savings associated with future energy efficiency improvements and DSM. In 1986, EPRI estimated that by the year 2000, utilities around the nation would save 5.7 percent[1] of total demand through DSM.[2]

In the first of three studies dealing with the impacts of energy-efficient technologies on the U.S. demand for electricity, EPRI concludes that the maximum technical potential for energy savings if all efficient technologies were implemented ranges from 24 percent to 44 percent of energy consumption in the year 2000.[3] The second report indicates that the forecast of electricity consumption in the year 2000 is already 8.5 percent lower than it would have been in the absence of efficiency improvements from efficiency standards,

1 If additional load-reducing programs such as interruptible and cogeneration as well as load building programs are included, demand and consumption savings are 6% and 8% of the total, respectively.

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

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

customer response to rising energy prices, and improved technologies.[4] The third EPRI report indicates that by the year 2000, DSM programs will have reduced the U.S. summer peak demand by 6.7 percent and annual electricity consumption by 3 percent.[5] By 2010, these reductions may be 9.6 percent and 5.8 percent, respectively.

Increased competition, interest in low-cost resources, and environmental concerns have heightened interest in demand-side resources. Although the estimated impacts of DSM described here include considerable uncertainty, the potential benefits should not be overlooked.

"Opportunities for Energy Efficiency in Texas" is a report on Phase I of a study conducted by the Center for Energy Studies (CES) of the University of Texas at Austin. This report presents a preliminary analysis of the opportunities for electrical energy savings in Texas for the next two decades. The study focuses on the residential and commercial sectors, which account for 61 percent of electrical energy consumption in Texas. The results reported in Phase I indicate that 99.7 million MWH, or 43 percent of the energy used by the residential and commercial sectors, could be conserved if all technically feasible efficiency measures were implemented.

The greatest potential impact on electricity consumption in the residential sector could be achieved through refrigerator-efficiency measures, freezer-efficiency measures, and automatic set back thermostats, while heating, ventilation, and air conditioning (HVAC) system improvements and high-efficiency cooling equipment may affect the commercial sector the most. If the relationships developed in the EPRI studies are reasonable for Texas, then about 30 percent of the technical potential savings, 12.9 percent of total usage, can be avoided through DSM programs by 2010. An additional one-third of the technically feasible savings might be achieved through appropriate changes in regulations, codes, and standards at various levels of government.

The table below compares historical DSM savings with two forecasts of expected DSM savings. More reliable figures for Texas will require further study, but certainly the potential for significant savings exists.

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

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

Comparison of Historical DSM Savings and Projected DSM Savings[6]

	Historical (Texas) 1980-1991 (%)	CES (Texas) 2010 (%)	EPRI (U.S.) 2010 (%)
Peak Demand	2.1	5.4	9.6
Energy Usage	0.1	12.9	5.8

6 The CES study addresses only the residential and commercial sectors. Historical data includes 1980 - 1991 (12 years), while the two forecasts address 20 years.

TABLE 5.9

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

TEXAS UTILITIES ELECTRIC COMPANY

Year	Passive	Active	Total DSM	Exogenous	Total
1992	(44)	(424)	(468)	61	(407)
1993	(100)	(452)	(552)	19	(533)
1994	(177)	(466)	(643)	(23)	(666)
1995	(266)	(490)	(756)	(55)	(811)
1996	(361)	(514)	(875)	(88)	(963)
1997	(477)	(538)	(1,015)	(118)	(1,133)
1998	(590)	(562)	(1,152)	(147)	(1,299)
1999	(716)	(587)	(1,303)	(152)	(1,455)
2000	(855)	(611)	(1,466)	(156)	(1,622)
2001	(993)	(635)	(1,628)	(161)	(1,789)
2002	(1,134)	(650)	(1,784)	(182)	(1,966)
2003	(1,269)	(665)	(1,934)	(181)	(2,115)
2004	(1,394)	(680)	(2,074)	(181)	(2,255)
2005	(1,529)	(695)	(2,224)	(180)	(2,404)
2006	(1,684)	(710)	(2,394)	(180)	(2,574)

TABLE 5.10

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

TEXAS UTILITIES ELECTRIC COMPANY

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(43,296)	(85,189)	(8,315)	0	1,681,042	1,544,242
1993	(100,269)	(186.065)	(18.718)	0	1,864,170	1,559,118
1994	(157,868)	(351,352)	(26.066)	0	2,114,533	1,579,247
1995	(203,152)	(536.281)	(47,145)	0	2,019,308	1,232,730
1996	(248,408)	(739,086)	(62,282)	0	2,043,276	993,500
1997	(286,625)	(997,030)	(80,226)	0	2,050,472	686,591
1998	(329,351)	(1,246,852)	(97.605)	0	2,052,821	379,013
1999	(344,187)	(1,531,443)	(117,257)	0	2,056,531	63,644
2000	(358,986)	(1,853,024)	(139,212)	0	2,055,223	(295,999)
2001	(373,408)	(2,172,028)	(160,901)	0	2,066,888	(639,449)
2002	(387,814)	(2,497,292)	(185.258)	0	1,933,207	(1,137,157)
2003	(405,753)	(2,801,123)	(208.603)	0	1,973,138	(1,442,341)
2004	(423,651)	(3,093,601)	(231.385)	0	2,008,325	(1,740,312)
2005	(441,442)	(3,405,893)	(254.715)	0	2,055,927	(2,046,123)
2006	(459,382)	(3,722,618)	(277.290)	0	2,099,128	(2,360,162)

TABLE 5.11

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

HOUSTON LIGHTING AND POWER COMPANY

Year	Passive	Active	Total DSM	Exogenous	Total
1992	(25)	(851)	(876)	(7)	(883)
1993	(62)	(895)	(957)	(18)	(975)
1994	(106)	(725)	(831)	(30)	(861)
1995	(171)	(858)	(1,029)	(38)	(1,067)
1996	(234)	(959)	(1,193)	(47)	(1,240)
1997	(302)	(1,002)	(1,304)	(54)	(1,358)
1998	(339)	(1,047)	(1,386)	(62)	(1,448)
1999	(376)	(1,090)	(1,466)	(62)	(1,528)
2000	(407)	(1,090)	(1,497)	(62)	(1,559)
2001	(442)	(1,090)	(1,532)	(62)	(1,594)
2002	(447)	(1,090)	(1,537)	(62)	(1,599)
2003	(453)	(1,090)	(1,543)	(62)	(1,605)
2004	(458)	(1,090)	(1,548)	(62)	(1,610)
2005	(464)	(1,090)	(1,554)	(62)	(1,616)
2006	(469)	(1,090)	(1,559)	(62)	(1,621)

TABLE 5.12

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

HOUSTON LIGHTING AND POWER COMPANY

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(25,202)	(6,246)	(3,426)	0	0	(34,874)
1993	(56,818)	(13,081)	(5,383)	0	0	(75,282)
1994	(90,204)	(19,795)	(6,466)	0	0	(116,465)
1995	(119,665)	(34,172)	(13,179)	0	0	(167,016)
1996	(144,803)	(50,197)	(20,791)	0	0	(215,791)
1997	(167,754)	(71,724)	(34,856)	0	0	(274,334)
1998	(191,275)	(94,210)	(50,749)	0	0	(336,234)
1999	(203,245)	(117,344)	(67,613)	0	0	(388,202)
2000	(203,245)	(130,198)	(81,623)	0	0	(415,066)
2001	(203,245)	(798,476)	(751,057)	0	0	(1,752,778)
2002	(203,245)	(798,476)	(752,213)	0	0	(1,753,934)
2003	(203,245)	(798,476)	(753,369)	0	0	(1,755,090)
2004	(203,245)	(798,476)	(754,525)	0	0	(1,756,246)
2005	(203,245)	(798,476)	(754,681)	0	0	(1,756,402)
2006	(203,245)	(798,476)	(756,837)	0	0	(1,758,558)

TABLE 5.13

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

GULF STATES UTILITIES COMPANY - TOTAL

Year	Passive	Active	Total DSM	Exogenous	Total
1992	0	(124)	(124)	(89)	(213)
1993	0	(124)	(124)	(100)	(224)
1994	0	(124)	(124)	(112)	(236)
1995	0	(124)	(124)	(138)	(262)
1996	0	(124)	(124)	(141)	(265)
1997	0	(124)	(124)	(143)	(267)
1998	0	(124)	(124)	(146)	(270)
1999	0	(124)	(124)	(146)	(270)
2000	0	(124)	(124)	(146)	(270)
2001	0	(139)	(139)	(146)	(285)
2002	0	(139)	(139)	(146)	(285)
2003	0	(139)	(139)	(146)	(285)
2004	0	(139)	(139)	(146)	(285)
2005	0	(139)	(139)	(146)	(285)
2006	0	(139)	(139)	(146)	(285)

TABLE 5.14

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

GULF STATES UTILITIES COMPANY - TOTAL

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(6,293)	0	(209,484)	0	0	(215,777)
1993	(14,568)	0	(227,004)	0	0	(241,572)
1994	(22,843)	0	(244,524)	0	0	(267,367)
1995	(28,925)	0	(297,522)	0	0	(326,447)
1996	(35,007)	0	(297,522)	0	0	(332,529)
1997	(39,730)	0	(297,522)	0	0	(337,252)
1998	(44,452)	0	(297,522)	0	0	(341,974)
1999	(44,452)	0	(297,522)	0	0	(341,974)
2000	(44,452)	0	(297,522)	0	0	(341,974)
2001	(44,452)	0	(297,522)	0	0	(341,974)
2002	(44,452)	0	(297,522)	0	0	(341,974)
2003	(44,452)	0	(297,522)	0	0	(341,974)
2004	(44,452)	0	(297,522)	0	0	(341,974)
2005	(44,452)	0	(297,522)	0	0	(341,974)
2006	(44,452)	0	(297,522)	0	0	(341,974)

TABLE 5.15

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

GULF STATES UTILITIES COMPANY - TEXAS

Year	Passive	Active	Total DSM	Exogenous	Total
1992	0	(91)	(91)	(41)	(132)
1993	0	(91)	(91)	(44)	(135)
1994	0	(91)	(91)	(52)	(143)
1995	0	(91)	(91)	(61)	(152)
1996	0	(91)	(91)	(63)	(154)
1997	0	(91)	(91)	(64)	(155)
1998	0	(91)	(91)	(66)	(157)
1999	0	(91)	(91)	(66)	(157)
2000	0	(91)	(91)	(66)	(157)
2001	0	(91)	(91)	(66)	(157)
2002	0	(91)	(91)	(66)	(157)
2003	0	(91)	(91)	(66)	(157)
2004	0	(91)	(91)	(66)	(157)
2005	0	(91)	(91)	(66)	(157)
2006	0	(91)	(91)	(66)	(157)

TABLE 5.16

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

GULF STATES UTILITIES COMPANY - TEXAS

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(3,131)	0	(97,236)	0	0	(100,367)
1993	(7,248)	0	(97,236)	0	0	(104,484)
1994	(11,365)	0	(112,566)	0	0	(123,931)
1995	(14,391)	0	(128,772)	0	0	(143,163)
1996	(17,417)	0	(128,772)	0	0	(146,189)
1997	(19,767)	0	(128,772)	0	0	(148,539)
1998	(22,116)	0	(128,772)	0	0	(150,888)
1999	(22,116)	0	(128,772)	0	0	(150,888)
2000	(22,116)	0	(128,772)	0	0	(150,888)
2001	(22,116)	0	(128,772)	0	0	(150,888)
2002	(22,116)	0	(128,772)	0	0	(150,888)
2003	(22,116)	0	(128,772)	0	0	(150,888)
2004	(22,116)	0	(128,772)	0	0	(150,888)
2005	(22,116)	0	(128,772)	0	0	(150,888)
2006	(22,116)	0	(128,772)	0	0	(150,888)

TABLE 5.17

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

CENTRAL POWER AND LIGHT COMPANY

Year	Passive	Active	Total DSM	Exogenous	Total
1992	(7)	(318)	(325)	(3)	(328)
1993	(14)	(333)	(347)	(8)	(355)
1994	(23)	(338)	(361)	(13)	(374)
1995	(35)	(343)	(378)	(17)	(395)
1996	(46)	(348)	(394)	(21)	(415)
1997	(55)	(353)	(408)	(24)	(432)
1998	(65)	(357)	(422)	(27)	(449)
1999	(76)	(362)	(438)	(27)	(465)
2000	(88)	(367)	(455)	(27)	(482)
2001	(99)	(372)	(471)	(27)	(498)
2002	(112)	(377)	(489)	(27)	(516)
2003	(116)	(381)	(497)	(27)	(524)
2004	(141)	(386)	(527)	(27)	(554)
2005	(158)	(391)	(549)	(27)	(576)
2006	(181)	(396)	(577)	(27)	(604)

TABLE 5.18

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

CENTRAL POWER AND LIGHT COMPANY

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(17,720)	(6,572)	11.848	0	0	(12,444)
1993	(38,638)	(13,263)	24.907	0	0	(26,994)
1994	(60,765)	(20,087)	39.215	0	0	(41,637)
1995	(81,932)	(27,051)	39.215	0	0	(69,768)
1996	(104,542)	(32,131)	39.215	0	0	(97,458)
1997	(127,220)	(33,559)	39.215	0	0	(121,564)
1998	(151,584)	(35,034)	39,215	0	0	(147,403)
1999	(172,847)	(36,556)	39.215	0	0	(170,188)
2000	(196,062)	(38,148)	39,215	0	0	(194,995)
2001	(221,393)	(38,148)	39.215	0	0	(220,326)
2002	(249,031)	(38,148)	39,215	0	0	(247,964)
2003	(279,183)	(38,148)	39,215	0	0	(278,116)
2004	(312,064)	(38,148)	39.215	0	0	(310,997)
2005	(347,931)	(38,148)	39.215	0	0	(346,864)
2006	(387,051)	(38,148)	39.215	0	0	(385,984)

TABLE 5.19

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

CITY PUBLIC SERVICE OF SAN ANTONIO

Year	Passive	Active	Total DSM	Exogenous	Total
1992	0	(10)	(10)	(2)	(12)
1993	0	(10)	(10)	(7)	(17)
1994	0	(10)	(10)	(11)	(21)
1995	0	(10)	(10)	(14)	(24)
1996	0	(10)	(10)	(18)	(28)
1997	0	(10)	(10)	(20)	(30)
1998	0	(10)	(10)	(23)	(33)
1999	0	(10)	(10)	(23)	(33)
2000	0	(10)	(10)	(23)	(33)
2001	0	(10)	(10)	(23)	(33)
2002	0	(10)	(10)	(23)	(33)
2003	0	(10)	(10)	(23)	(33)
2004	0	(10)	(10)	(23)	(33)
2005	0	(10)	(10)	(23)	(33)
2006	0	(10)	(10)	(23)	(33)

TABLE 5.20

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

CITY PUBLIC SERVICE OF SAN ANTONIO

Year	Residential	Commercial	Industriai	Other	Wholesale	Total
1992	(5,784)	0	0	0	0	(5,784)
1993	(13,570)	0	0	0	0	(13,570)
1994	(21,356)	0	0	0	0	(21,356)
1995	(27,091)	0	0	0	0	(27,091)
1996	(32,827)	0	0	0	0	(32,827)
1997	(37,331)	0	0	0	0	(37,331)
1998	(41,835)	0	0	0	0	(41,835)
1999	(41,835)	0	0	0	0	(41,835)
2000	(41,835)	0	0	0	0	(41,835)
2001	(41,835)	0	0	0	0	(41,835)
2002	(41,835)	0	0	0	0	(41,835)
2003	(41,835)	0	0	0	0	(41,835)
2004	(41,835)	0	0	0	0	(41,835)
2005	(41,835)	0	0	0	0	(41,835)
2006	(41,835)	0	0	0	0	(41,835)

TABLE 5.21

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Passive	Active	Total DSM	Exogenous	Total
1992	0	(15)	(15)	8	(7)
1993	0	(54)	(54)	60	6
1994	0	(54)	(54)	58	4
1995	0	(54)	(54)	57	3
1996	0	(54)	(54)	109	55
1997	0	(54)	(54)	111	57
1998	0	(54)	(54)	112	58
1999	0	(54)	(54)	114	60
2000	0	(54)	(54)	116	62
2001	0	(54)	(54)	119	65
2002	0	(54)	(54)	119	65
2003	0	(54)	(54)	119	65
2004	0	(54)	(54)	119	65
2005	0	(54)	(54)	119	65
2006	0	(54)	(54)	119	65

TABLE 5.22

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

SOUTHWESTERN PUBLIC SERVICE COMPANY - TOTAL

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	23,427	313	0	0	27,690	51,430
1993	47,782	335	0	0	402,101	450,218
1994	73,224	609	0	0	410,994	484,827
1995	100,541	894	0	0	706,178	807,613
1996	128,965	1,188	0	0	722,837	852,990
1997	159,287	1,496	0	0	739,708	900,491
1998	190,935	1,817	0	0	757,042	949,794
1999	225,140	2,091	0	0	774,778	1,002,009
2000	260,710	2,438	0	0	792,948	1,056,096
2001	297,706	2,799	0	0	792,948	1,093,453
2002	297,706	3,160	0	0	792,948	1,093,814
2003	297,706	3,521	0	0	792,948	1,094,175
2004	297,706	3,882	0	0	792,948	1,094,536
2005	297,706	4,243	0	0	792,948	1,094,897
2006	297,706	4,604	0	0	792,948	1,095,258

TABLE 5.23

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Passive	Active	Total DSM	Exogenous	Total
1992	0	(15)	(15)	9	(6)
1993	0	(54)	(54)	61	7
1994	0	(54)	(54)	60	6
1995	0	(54)	(54)	60	6
1996	0	(54)	(54)	112	58
1997	0	(54)	(54)	114	60
1998	0	(54)	(54)	115	61
1999	0	(54)	(54)	117	63
2000	0	(54)	(54)	119	65
2001	0	(54)	(54)	122	68
2002	0	(54)	(54)	122	68
2003	0	(54)	(54)	122	68
2004	0	(54)	(54)	122	68
2005	0	(54)	(54)	122	68
2006	0	(54)	(54)	122	68

TABLE 5.24

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

SOUTHWESTERN PUBLIC SERVICE COMPANY - TEXAS

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	24,140	313	0	0	27,690	52,143
1993	49,237	335	0	0	402,101	451,673
1994	75,422	609	0	0	410,994	487,025
1995	103,273	894	0	0	706,178	810,345
1996	132,230	1,188	0	0	722,837	856,255
1997	162,912	1,496	0	0	739,708	904,116
1998	194,921	1,817	0	0	757,042	953,780
1999	229,126	2,091	0	0	774,778	1,005,995
2000	264,696	2,438	0	0	792,948	1,060,082
2001	301,692	2,799	0	0	792,948	1,097,439
2002	301,692	3,160	0	0	792,948	1,097,800
2003	301,692	3,521	0	0	792,948	1,098,161
2004	301,692	3,882	0	0	792,948	1,098,522
2005	301,692	4,243	0	0	792,948	1,098,883
2006	301,692	4,604	0	0	792,948	1,099,244

TABLE 5.25

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

Year	Passive	Active	Total DSM	Exogenous	Total
1992	0	(61)	(61)	(5)	(66)
1993	0	(61)	(61)	(11)	(72)
1994	0	(61)	(62)	(19)	(80)
1995	(1)	(61)	(62)	(25)	(86)
1996	(1)	(61)	(62)	(30)	(92)
1997	(1)	(61)	(62)	(36)	(98)
1998	(1)	(61)	(62)	(42)	(104)
1999	(2)	(61)	(63)	(42)	(105)
2000	(2)	(61)	(63)	(42)	(105)
2001	(2)	(61)	(63)	(42)	(105)
2002	(3)	(61)	(64)	(42)	(106)
2003	(3)	(61)	(64)	(42)	(106)
2004	(3)	(61)	(64)	(42)	(106)
2005	(4)	(61)	(65)	(42)	(107)
2006	(4)	(61)	(65)	(42)	(107)

TABLE 5.26

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

SOUTHWESTERN ELECTRIC POWER COMPANY - TOTAL

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(9,165)	(8,974)	0	0	0	(18,139)
1993	(20,925)	(20,678)	0	0	0	(41,603)
1994	(32,683)	(32,458)	0	0	0	(65,141)
1995	(41,308)	(44,316)	0	0	0	(85,624)
1996	(49,930)	(56,254)	0	0	0	(106,184)
1997	(56,545)	(68,273)	0	0	0	(124,818)
1998	(63,160)	(80,374)	0	0	0	(143,534)
1999	(63,160)	(80,374)	0	0	0	(143,534)
2000	(63,160)	(80,374)	0	0	0	(143,534)
2001	(63,160)	(80,374)	0	0	0	(143,534)
2002	(63,160)	(80,374)	0	0	0	(143,534)
2003	(63,160)	(80,374)	0	0	0	(143,534)
2004	(63,160)	(80,374)	0	0	0	(143,534)
2005	(63,160)	(80,374)	0	0	0	(143,534)
2006	(63,160)	(80,374)	0	0	0	(143,534)

TABLE 5.27

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Passive	Active	Total DSM	Exogenous	Total
1992	0	(58)	(59)	(2)	(60)
1993	0	(58)	(59)	(4)	(63)
1994	0	(58)	(59)	(7)	(66)
1995	(1)	(58)	(59)	(9)	(68)
1996	(1)	(58)	(59)	(11)	(71)
1997	(1)	(58)	(60)	(14)	(73)
1998	(1)	(58)	(60)	(16)	(75)
1999	(2)	(58)	(60)	(16)	(76)
2000	(2)	(58)	(60)	(16)	(76)
2001	(2)	(58)	(61)	(16)	(76)
2002	(3)	(58)	(61)	(16)	(77)
2003	(3)	(58)	(61)	(16)	(77)
2004	(3)	(58)	(62)	(16)	(77)
2005	(4)	(58)	(62)	(16)	(78)
2006	(4)	(58)	(62)	(16)	(78)

TABLE 5.28

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

SOUTHWESTERN ELECTRIC POWER COMPANY - TEXAS

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(3,666)	(3,141)	0	0	0	(6,807)
1993	(8,370)	(7,237)	0	0	0	(15,607)
1994	(13,073)	(11,360)	0	0	0	(24,433)
1995	(16,523)	(15,511)	0	0	0	(32,034)
1996	(19,972)	(19,689)	0	0	0	(39,661)
1997	(22,618)	(23,896)	0	0	0	(46,514)
1998	(25,264)	(28,131)	0	0	0	(53,395)
1999	(25,264)	(28,131)	0	0	0	(53,395)
2000	(25,264)	(28,131)	0	0	0	(53,395)
2001	(25,264)	(28,131)	0	0	0	(53,395)
2002	(25,264)	(28,131)	0	0	0	(53,395)
2003	(25,264)	(28,131)	0	0	0	(53,395)
2004	(25,264)	(28,131)	0	0	0	(53,395)
2005	(25,264)	(28,131)	0	0	0	(53,395)
2006	(25,264)	(28,131)	0	0	0	(53,395)

TABLE 5.29

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

LOWER COLORADO RIVER AUTHORITY - SUMMER

Year	Passive	Active	Total DSM	Exogenous	Total
1992	(2)	(27)	(29)	(2)	(31)
1993	(5)	(28)	(33)	(6)	(39)
1994	(8)	(28)	(37)	(10)	(47)
1995	(11)	(28)	(40)	(13)	(53)
1996	(15)	(31)	(46)	(17)	(63)
1997	(19)	(38)	(57)	(19)	(76)
1998	(23)	(47)	(70)	(22)	(92)
1999	(27)	(54)	(81)	(22)	(103)
2000	(30)	(67)	(97)	(22)	(119)
2001	(34)	(67)	(101)	(22)	(123)
2002	(38)	(67)	(105)	(22)	(127)
2003	(42)	(67)	(109)	(22)	(131)
2004	(45)	(67)	(112)	(22)	(134)
2005	(49)	(67)	(116)	(22)	(138)
2006	(53)	(67)	(120)	(22)	(142)

TABLE 5.30

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

LOWER COLORADO RIVER AUTHORITY - SUMMER

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(6,737)	(630)	0	0	0	(7,367)
1993	(15,083)	(1,260)	0	0	0	(16,343)
1994	(23,895)	(1,890)	0	0	0	(25,785)
1995	(31,566)	(2,520)	0	0	0	(34,086)
1996	(39,469)	(3,150)	0	0	0	(42,619)
1997	(46,419)	(3,780)	0	0	0	(50,199)
1998	(53,368)	(4,410)	0	0	0	(57,778)
1999	(57,373)	(5,040)	0	0	0	(62,413)
2000	(61,378)	(5,670)	0	0	0	(67,048)
2001	(65,383)	(6,300)	0	0	0	(71,683)
2002	(69,388)	(6,930)	0	0	0	(76,318)
2003	(73,393)	(7,560)	0	0	0	(80,953)
2004	(77,398)	(8,190)	0	0	0	(85,588)
2005	(81,403)	(8,820)	0	0	0	(90,223)
2006	(85,408)	(9,450)	0	0	0	(94,858)

TABLE 5.31

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

CITY OF AUSTIN ELECTRIC UTILITY

Year	Passive	Active	Total DSM	Exogenous	Total
1992	(29)	(4)	(33)	0	(33)
1993	(39)	(6)	(45)	0	(45)
1994	(59)	(8)	(67)	0	(67)
1995	(72)	(11)	(83)	0	(83)
1996	(90)	(15)	(105)	0	(105)
1997	(108)	(19)	(127)	0	(127)
1998	(127)	(24)	(151)	0	(151)
1999	(147)	(29)	(176)	0	(176)
2000	(169)	(34)	(203)	0	(203)
2001	(188)	(39)	(227)	0	(227)
2002	(206)	(45)	(251)	0	(251)
2003	(229)	(47)	(276)	0	(276)
2004	(255)	(49)	(304)	0	(304)
2005	(276)	(50)	(326)	0	(326)
2006	(299)	(51)	(350)	0	(350)

TABLE 5.32

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

CITY OF AUSTIN ELECTRIC UTILITY

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(44,322)	(46,808)	0	0	0	(91,130)
1993	(69,525)	(66,546)	0	0	0	(136,071)
1994	(96,611)	(88,057)	0	0	0	(184,668)
1995	(125,354)	(110,434)	0	0	0	(235,788)
1996	(153,500)	(134,220)	0	0	0	(287,720)
1997	(182,436)	(159,457)	0	0	0	(341,893)
1998	(212,009)	(189,909)	0	0	0	(401,918)
1999	(241,036)	(223,376)	0	0	0	(464,412)
2000	(272,271)	(259,026)	0	0	0	(531,297)
2001	(301,802)	(296,437)	0	0	0	(598,239)
2002	(330,614)	(335,673)	0	0	0	(666,287)
2003	(361,329)	(376,887)	0	0	0	(738,216)
2004	(393,064)	(420,550)	0	0	0	(813,614)
2005	(423,750)	(464,020)	0	0	0	(887,770)
2006	(455,506)	(510,151)	0	0	0	(965,657)

TABLE 5.33

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

WEST TEXAS UTILITIES COMPANY

Year	Passive	Active	Total DSM	Exogenous	Total
1992	(1)	0	(1)	(1)	(2)
1993	(3)	0	(3)	(3)	(6)
1994	(4)	0	(4)	(5)	(9)
1995	(5)	0	(5)	(6)	(11)
1996	(7)	0	(7)	(8)	(15)
1997	(8)	0	(8)	(9)	(17)
1998	(9)	0	(9)	(10)	(19)
1999	(11)	0	(11)	(10)	(21)
2000	(12)	0	(12)	(10)	(22)
2001	(14)	0	(14)	(10)	(24)
2002	(15)	0	(15)	(10)	(25)
2003	(17)	0	(17)	(10)	(27)
2004	(18)	0	(18)	(10)	(28)
2005	(20)	0	(20)	(10)	(30)
2006	(21)	0	(21)	(10)	(31)

TABLE 5.34

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

WEST TEXAS UTILITIES COMPANY

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(1,970)	493	(6,632)	0	0	(8,109)
1993	(4,551)	1,575	(13,264)	0	0	(16,240)
1994	(7,137)	3,199	(19,896)	0	0	(23,834)
1995	(9,085)	4,733	(26,528)	0	0	(30,880)
1996	(11,033)	6,176	(33,160)	0	0	(38,017)
1997	(12,596)	7,530	(39,792)	0	0	(44,858)
1998	(14,161)	8,793	(46,424)	0	0	(51,792)
1999	(14,335)	9,966	(53,056)	0	0	(57,425)
2000	(14,512)	11,048	(59,688)	0	0	(63,152)
2001	(14,693)	12,131	(66,320)	0	0	(68,882)
2002	(14,876)	13,214	(72,952)	0	0	(74,614)
2003	(15,064)	14,296	(79,584)	0	0	(80,352)
2004	(15,256)	15,379	(86,216)	0	0	(86,093)
2005	(15,452)	16,462	(92,848)	0	0	(91,838)
2006	(15,652)	17,544	(99,480)	0	0	(97,588)

TABLE 5.35

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

EL PASO ELECTRIC COMPANY - TOTAL

Year	Passive	Active	Total DSM	Exogenous	Total
1992	(1)	0	(1)	(1)	(2)
1993	(3)	0	(3)	(1)	(4)
1994	(4)	0	(4)	(2)	(6)
1995	(6)	0	(6)	(3)	(9)
1996	(8)	0	(8)	(3)	(11)
1997	(10)	0	(10)	(3)	(13)
1998	(12)	0	(12)	(4)	(16)
1999	(13)	0	(13)	(4)	(17)
2000	(15)	0	(15)	(4)	(19)
2001	(17)	0	(17)	(4)	(21)
2002	(19)	0	(19)	(4)	(23)
2003	(21)	0	(21)	(4)	(25)
2004	(23)	0	(23)	(4)	(27)
2005	(24)	0	(24)	(4)	(28)
2006	(26)	0	(26)	(4)	(30)

TABLE 5.36

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

EL PASO ELECTRIC COMPANY - TOTAL

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(1,153)	(1,355)	0	0	0	(2,508)
1993	(2,194)	(3,161)	0	0	0	(5,355)
1994	(3,235)	(5,871)	0	0	0	(9,106)
1995	(3,967)	(8,581)	0	0	0	(12,548)
1996	(4,700)	(11,291)	0	0	0	(15,991)
1997	(5,136)	(14,001)	0	0	0	(19,137)
1998	(5,573)	(16,711)	0	0	0	(22,284)
1999	(5,573)	(19,421)	0	0	0	(24,994)
2000	(5,573)	(22,131)	0	0	0	(27,704)
2001	(5,573)	(24,841)	0	0	0	(30,414)
2002	(5,573)	(27,551)	0	0	0	(33,124)
2003	(5,573)	(30,261)	0	0	0	(35,834)
2004	(5,573)	(32,971)	0	0	0	(38,544)
2005	(5,573)	(35,681)	0	0	0	(41,254)
2006	(5,573)	(38,391)	0	0	0	(43,964)

TABLE 5.37

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

EL PASO ELECTRIC COMPANY - TEXAS

Year	Passive	Active	Total DSM	Exogenous	Total
1992	(1)	0	(1)	(1)	(2)
1993	(3)	0	(3)	(1)	(4)
1994	(4)	0	(4)	(2)	(6)
1995	(6)	0	(6)	(3)	(9)
1996	(8)	0	(8)	(3)	(11)
1997	(10)	0	(10)	(3)	(13)
1998	(12)	0	(12)	(4)	(16)
1999	(13)	0	(13)	(4)	(17)
2000	(15)	0	(15)	(4)	(19)
2001	(17)	0	(17)	(4)	(21)
2002	(19)	0	(19)	(4)	(23)
2003	(21)	0	(21)	(4)	(25)
2004	(23)	0	(23)	(4)	(27)
2005	(24)	0	(24)	(4)	(28)
2006	(26)	0	(26)	(4)	(30)

TABLE 5.38

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

EL PASO ELECTRIC COMPANY - TEXAS

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(1,153)	(1,355)	0	0	0	(2,508)
1993	(2,194)	(3,161)	0	0	0	(5,355)
1994	(3,235)	(5,871)	0	0	0	(9,106)
1995	(3,967)	(8,581)	0	0	0	(12,548)
1996	(4,700)	(11,291)	0	0	0	(15,991)
1997	(5,136)	(14,001)	0	0	0	(19,137)
1998	(5,573)	(16,711)	0	0	0	(22,284)
1999	(5,573)	(19,421)	0	0	0	(24,994)
2000	(5,573)	(22,131)	0	0	0	(27,704)
2001	(5,573)	(24,841)	0	0	0	(30,414)
2002	(5,573)	(27,551)	0	0	0	(33,124)
2003	(5,573)	(30,261)	0	0	0	(35,834)
2004	(5,573)	(32,971)	0	0	0	(38,544)
2005	(5,573)	(35,681)	0	0	0	(41,254)
2006	(5,573)	(38,391)	0	0	0	(43,964)

TABLE 5.39

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

TEXAS-NEW MEXICO POWER COMPANY

Year	Passive	Active	Total DSM	Exogenous	Total
1992	(2)	0	(2)	(2)	(4)
1993	(4)	0	(4)	(4)	(8)
1994	(6)	0	(6)	(6)	(12)
1995	(8)	0	(8)	(8)	(16)
1996	(10)	0	(10)	(9)	(19)
1997	(12)	0	(12)	(11)	(23)
1998	(14)	0	(14)	(12)	(26)
1999	(16)	0	(16)	(12)	(28)
2000	(18)	0	(18)	(12)	(30)
2001	(18)	0	(18)	(12)	(30)
2002	(18)	0	(18)	(12)	(30)
2003	(18)	0	(18)	(12)	(30)
2004	(18)	0	(18)	(12)	(30)
2005	(18)	0	(18)	(12)	(30)
2006	(18)	0	(18)	(12)	(30)

TABLE 5.40

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

TEXAS-NEW MEXICO POWER COMPANY

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(3,200)	0	0	0	0	(3,200)
1993	(7,729)	0	0	0	0	(7,729)
1994	(12,985)	0	0	0	0	(12,985)
1995	(17,585)	0	0	0	0	(17,585)
1996	(22,253)	0	0	0	0	(22,253)
1997	(26,465)	0	0	0	0	(26,465)
1998	(30,556)	0	0	0	0	(30,556)
1999	(32,952)	0	0	0	0	(32,952)
2000	(35,329)	0	0	0	0	(35,329)
2001	(35,329)	0	0	0	0	(35,329)
2002	(35,329)	0	0	0	0	(35,329)
2003	(35,329)	0	0	0	0	(35,329)
2004	(35,329)	0	0	0	0	(35,329)
2005	(35,329)	0	0	0	0	(35,329)
2006	(35,329)	0	0	0	0	(35,329)

TABLE 5.41

CUMULATIVE MEGAWATT IMPACTS
AT THE POINT OF GENERATION

BRAZOS ELECTRIC POWER COOPERATIVE, INC.

Year	Passive	Active	Total DSM	Exogenous	Total
1992	0	0	0	(2)	(2)
1993	(1)	0	(1)	(4)	(5)
1994	(2)	0	(2)	(5)	(7)
1995	(3)	0	(3)	(7)	(10)
1996	(5)	0	(5)	(8)	(13)
1997	(7)	0	(7)	(10)	(17)
1998	(9)	0	(9)	(11)	(20)
1999	(12)	0	(12)	(11)	(23)
2000	(14)	0	(14)	(11)	(25)
2001	(16)	0	(16)	(11)	(27)
2002	(19)	0	(19)	(11)	(30)
2003	(21)	0	(21)	(11)	(32)
2004	(23)	0	(23)	(11)	(34)
2005	(26)	0	(26)	(11)	(37)
2006					

TABLE 5.42

MEGAWATT-HOUR IMPACTS
AT THE CUSTOMER METER

BRAZOS ELECTRIC POWER COOPERATIVE, INC.

Year	Residential	Commercial	Industrial	Other	Wholesale	Total
1992	(2,284)	0	0	0	0	(2,284)
1993	(5,413)	0	0	0	0	(5,413)
1994	(9,018)	0	0	0	0	(9,018)
1995	(12,603)	0	0	0	0	(12,603)
1996	(16,659)	0	0	0	0	(16,659)
1997	(20,556)	0	0	0	0	(20,556)
1998	(24,503)	0	0	0	0	(24,503)
1999	(27,113)	0	0	0	0	(27,113)
2000	(29,775)	0	0	0	0	(29,775)
2001	(32,491)	0	0	0	0	(32,491)
2002	(35,261)	0	0	0	0	(35,261)
2003	(38,086)	0	0	0	0	(38,086)
2004	(40,968)	0	0	0	0	(40,968)
2005	(43,907)	0	0	0	0	(43,907)
2006	(46,905)	0	0	0	0	(46,905)

CHAPTER SIX

RESOURCE PLAN

Introduction

The electric industry in Texas has experienced a unique period in its history that could be characterized as follows:

1. Highly capital intensive construction.
2. Slow growth in demand.
3. Multiple rate increases.
4. Excess capacity.

The Texas economy has gone through a restructuring process that has included diversification giving it a strong base to avoid the kind of economic slowdowns experienced in the 1986-1988 period. As a result, a steady growth in the demand for electricity is expected in the foreseeable future. This growth in demand, along with the retirement of aging generation plants, will result in the elimination of surplus capacity and indicates a need for some additional capacity in the second half of the 1990s and early 2000s.

There is growing awareness of the economical alternatives to power plant construction. These alternatives include cogeneration, conservation, and renewable resources -- the three pillars of energy efficiency. Cogeneration technologies allow the more efficient use of fuels (usually natural gas), extracting more energy from fossil fuels, compared with traditional electricity production. Conservation technologies increase the efficiency of electricity use. The efficient use of existing energy supplies delays the expansion of fossil fuel usage. Finally, renewable technologies allow the use of plentiful natural resources such as wind and sunlight, but will require investment in new technologies. These alternatives may have a significant impact on the magnitude of any power plant construction in the future.

Load and capacity resource planning activities have been performed by the PUCT staff since the creation of the Commission more than fifteen years ago. However, the 1983 amendments to the Public Utility Regulatory Act (PURA) added a new dimension to the load and capacity resource planning activities of the PUCT. Article III, Section 16(b) states that:

> The commission shall develop a long-term statewide electrical energy forecast which shall be sent to the governor biennially. The forecast will include an assessment of how alternative energy sources, conservation, and load management will meet the state's electricity needs.

Further references are made in PURA to the "statewide electrical energy plan" (SEEP) in Articles VI (dealing with proceedings before the regulatory authority) and VII (dealing with the certificates of convenience and necessity). In these Articles, utilities are explicitly required to demonstrate that their load and capacity resource plans are compatible with the Commission's most recently developed statewide electrical energy plan.

The resource plans presented in this chapter satisfy some of the PURA requirements regarding the development of the statewide electrical energy plan. The remaining sections of this chapter analyze the process of integrated resource planning, consider reliability issues, and review near-term additions to the stock of generating units as well as 10-year capacity additions.[1] Alternative capacity resources, including the availability of cogeneration, are also described. The base-case capacity resource plan relies on the PUCT staff's recommendations for demand-side management programs (Chapter Five), purchases of cogenerated power, purchases from other utilities, and other alternatives. Finally, some discussion of flexibility in staff resource plans to deal with forecast uncertainties is provided. The staff's capacity resource plans are presented in Appendix A.

The Integrated Resource Planning Process

Integrated resource planning is the analytical framework for considering all electricity resource options in a comprehensive and balanced manner. It is sometimes referred to as integrated least-cost utility planning.

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1 The "10-year" forecast and resource plan discussed throughout this report covers the period 1992 to 2001 (or 10 years, inclusive).

Electric utility resource planning involves the following activities:

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

Electric utilities try to satisfy various resource planning objectives, ranging from the maintenance of system reliability to environmental compliance, all within the framework of government regulation. Therefore, it is important that utilities look at different options when preparing a resource plan. Flexible resource plans facilitate the efficient utilization of capacity. Resource planning helps insure that present and future customers are provided with electric services in a reliable manner at the lowest possible cost, within a given set of financial and regulatory constraints. The electric utility must prepare a forecast of demand, examine and select resources, prepare and implement plans for resource acquisition, and evaluate past planning decisions.

Resource planning is a dynamic process in which a utility tries to optimize resources, balancing several objectives that sometimes conflict with each other. For example, a higher level of reliability in the electrical system requires additional reserves on the system and costs ratepayers more. An optimization goal relies on an objective function (for example, the minimization of the present value of revenue requirements), a modeling process, and input assumptions to derive a "best" plan for the future. The optimization process requires an appropriate model in which the restrictions of the system have been quantified and includes good forecasting techniques.

Management of uncertainty, within the IRP process, recognizes that future events (fuel costs, technology, or customer demand, for example) cannot be known in advance.

Preparation of alternative scenarios, such as those which rely on high and low rates of growth, illuminates the most significant costs of an uncertain operating environment. Flexibility reduces the risks associated with uncertainty. The consequence of a suboptimal resource plan is the imposition of unnecessary costs on the utility's ratepayers resulting in either more than adequate capacity, or inadequate capacity for an unreasonable period of time.

System Reliability and Reserve Margins

Most of the electric utilities in the U.S. have adequate generating capacity. In 1991, the installed generating reserve of U.S. utilities as a group was about 25 percent, with 15 to 20 percent considered adequate for reliability purposes. Calculated reserve margins would be even higher if the demand-reducing impact of interruptible loads were considered.[2]

Texas utilities, like utilities throughout the U.S., have surplus capacity. Generating utilities in Texas had a reserve margin of about 32 percent in 1981. Including the demand-reducing impact of interruptible loads, the 1991 reserve margin for Texas was 35 percent. However, the statewide reserve margin should decline gradually to about 19 percent in 2001 if the proposed resource plans materialize throughout the state. ERCOT utilities have experienced similar reserve margins during the last ten years and are expected to reduce the reserve margin to 19 percent by 2001.

For the next ten years, reserve margins will remain above the minimum levels recommended by ERCOT and other adjoining reliability councils. The need for new supply sources may become apparent by the late 1990s or early in the 21st century. Any significant investment in new generating capacity prior to that time may represent a misallocation of resources. To insure a reliable system and efficient use of available resources, it is crucial for utility planners to incorporate conventional and unconventional resources in planning to achieve an appropriate balance between cost and reliability.

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2 Several electric resource planning organizations, such as the North American Electric Reliability Council, calculate reserve margins without considering the impact of interruptible loads. In contrast, it is PUCT staff practice to calculate reserve margins using peak demand less interruptible loads. Including the impact of interruptible loads increases the amount of capacity available for planning purposes. That is, the calculated reserve margin is higher under this treatment (all else equal).

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

National Reliability Assessment

NERC prepares an annual assessment of reliability, which in 1992 included a finding that the 10-year supply plans of electric utilities should have adequate resources in most parts of the United States and Canada. With increased emphasis on short lead-time options, planned resources are being closely matched to projected demands. NERC identified a number of challenges to the maintenance of system reliability:

1. Clean air regulations that require electric utilities to switch fuel supplies or modify power plants.
2. Significant increase in the use of natural gas for electricity generation that may effect deliverability.
3. Increased operating complexities due to clean air regulations, use of non-utility generators, and increased use of transmission systems.
4. Increased impediments in transmission line construction that may create difficulties in meeting increased demand for transmission service.
5. Changing business environment brought about by increased competition, demand-side management, and consideration of environmental constraints.

NERC recognized other challenges to reliability or risks to supply in addition to the above. It is important to study the issues identified by NERC and other agencies in the evaluation of the reliability of the electric system in Texas. Table 6.1 shows the 1991 (actual) and 2001 (projected) capability and generation by fuel type for the U.S. portion of NERC and for Texas.

Texas Reliability Assessment

Texas electric utility service areas are in three of the NERC reliability regions. Reported characteristics for each reliability region are shown in Table 6.2 for 1991 and compared to projections for 2001. The numbers in this table are based on utility projections and are given for comparison purposes. They do not necessarily indicate Commission staff endorsement.

The majority of Texas is in ERCOT, which has the heaviest dependence on natural gas of the three reliability regions. An estimated 39.7 percent of ERCOT's generation in 2001 is expected to be provided by natural gas-fueled units. Dependence on natural gas in the ERCOT generation mix represents some reliability concern. Over the short term, the abundance of cheap natural gas will contribute to the reliability of the Texas generation mix. However, if severe winter conditions were to occur, there could be curtailments of gas supplies for generating units. If curtailments do occur and it becomes necessary to substitute fuel oil for gas, the rated capability of some units will be reduced because of equipment design, pipeline delivery constraints, and/or oil inventories. Additional capacity may be available from other sources, such as cogenerators within ERCOT, if such a reduction in capability exceeds available capacity reserves. Generally, natural gas may be a reliable fuel over the next several years, but greater demand may lead to some uncertainty in the reliability of natural gas in the generation mix, over the long term.

An estimated 11 percent of 2001 energy is expected to be provided by nuclear plants. Although nuclear plants nationwide run at relatively low capacity factors relative to other base load units, the reliability of the ERCOT system is not expected to be compromised. Nuclear fuel prices are less sensitive to energy markets because of lead times for nuclear material and services. Although the capital costs are much higher for nuclear plants, the fuel component of total cost is considerably less than for fossil-fueled units. Coal-fired units as a percentage of total capacity are expected to decline somewhat in the SPP and WSCC regions and increase slightly in ERCOT over the next ten years. Although coal-fired units as a percentage of generation slightly decline, these units are part of the needed diversification of the Texas generation mix and are expected to improve long-term reliability.

TABLE 6.1
NATIONAL VS. TEXAS CAPACITY AND
GENERATION BY FUEL TYPE

	NERC - U.S. 1991	NERC - U.S. 2001	Texas Total 1991	Texas Total 2001
CAPACITY MIX (%)				
GAS/OIL FIRED	27.7%	30.3%	58.2%	59.1%
COAL FIRED	41.8%	38.4%	26.9%	27.5%
NUCLEAR	14.4%	13.6%	6.8%	7.8%
HYDRO	10.1%	8.8%	0.8%	0.7%
NON-UTILITY GENERATION	3.1%	5.5%	5.1%	2.8%
OTHER (UTILITY)	2.9%	3.3%	2.2%	2.2%
TOTAL	100.0%	100.0%	100.0%	100.0%
CAPABILITY (1,000 MW)	690.9	778.1	65	72
SUMMER PEAK LOAD (1,000 MW)*	551.3	661.5	48	61
RESERVE (%)*	27.9%	20.8%	33.3%	18.1%
GENERATION MIX (%)				
GAS/OIL FIRED	12.1%	13.7%	35.3%	39.6%
COAL FIRED	52.8%	51.6%	43.8%	41.7%
NUCLEAR	20.9%	19.3%	9.7%	11.0%
HYDRO	9.3%	7.4%	0.5%	0.3%
NON-UTILITY GENERATION	4.6%	7.6%	9.9%	5.8%
OTHER (UTILITY)	0.4%	0.4%	0.8%	1.6%
TOTAL	100.0%	100.0%	100.0%	100.0%
GENERATION (THOUSANDS OF MWH)	2,929,238	3,472,940	260,564	329,869

NOTES:

U.S. Figures are derived from various North American Electric Reliability Council Publications.

Texas total data are derived from the Texas portion of generating utilities under the jurisdiction of the PUCT.

* NERC reserve margin and peak load for 1991 are estimated.

TABLE 6.2
CAPACITY AND GENERATION BY FUEL TYPE IN
THREE RELIABILITY REGIONS SERVING TEXAS

	SOUTHWEST POWER POOL (SPP)		WESTERN SYSTEMS COORDINATING COUNCIL (WSCC)		ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)	
	1991	2001	1991	2001	1991	2001
CAPACITY MIX (%)*						
GAS/OIL FIRED	46.4%	48.7%	24.4%	26.0%	60.4%	59.9%
COAL FIRED	39.8%	38.0%	23.4%	21.4%	26.2%	28.2%
NUCLEAR	8.7%	8.0%	8.5%	7.7%	6.7%	7.7%
HYDRO	3.7%	3.6%	33.1%	31.1%	0.8%	0.7%
NON-UTILITY GENERATION	0.7%	1.1%	6.3%	9.1%	5.9%	3.5%
OTHER (UTILITY)	0.7%	0.6%	4.3%	4.7%	0.0%	0.0%
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CAPABILITY (1,000 MW)	67.4	73.2	150	163	55	62
SUMMER PEAK LOAD (1,000 MW)*	51.9	63.4	105	130	42	55
RESERVE MARGIN**	29.7%	19.3%	36.0%	29.1%	27.8%	16.6%
GENERATION MIX (%)*						
GAS/OIL FIRED	23.3%	27.6%	9.5%	13.6%	36.4%	39.7%
COAL FIRED	55.8%	55.0%	35.6%	32.8%	42.9%	42.2%
NUCLEAR	16.5%	13.6%	12.1%	11.1%	9.8%	11.0%
HYDRO	2.2%	2.0%	29.9%	26.8%	0.3%	0.3%
NON-UTILITY GENERATION	2.0%	1.8%	10.3%	14.0%	10.6%	6.8%
OTHER (UTILITY)	0.1%	0.1%	2.5%	1.6%	0.1%	0.0%
TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
GENERATION (THOUSANDS OF MWH)	257,434	311,261	649,876	803,266	211,568	276,742

NOTES:

Source: Various North American Electric Reliability Council Publications.

* 1991 numbers are estimates.

** Reserve margin is calculated as planned capacity minus peak demand adjusted for direct control load management and interruptible demand as a percentage of adjusted peak demand.

Another concern over the reliability of the ERCOT system is the increasing dependence on non-utility generation. The long-term reliability of non-utility generation has not been established as many facilities have been in service for less than ten years. More recently, concerns have arisen over dispatchability, minimum load constraints, transmission and wheeling, and long-term availability. The ERCOT projected use of non-utility generation in 2001 is about 6.8 percent, which is lower than the corresponding figure for the WSCC and for the U.S. portion of NERC. However, the ERCOT non-utility generation figure may be understated as a result of contract uncertainties. Because of the abundance of industries in the Gulf Coast region that can cogenerate, recognition of the role of NUGs is essential for planning.

Major Texas Generating Utilities Target Reserve Margins

The statewide resource plan is dependent on projected peak demands and target reserve margins for the major generating utilities in Texas. Supply resources must be greater than projected peak demands to provide a reliable electric system. The reliability margin is the amount by which the net capability (installed capacity plus net available power from other supply sources) exceeds the peak demand adjusted for demand-side resource effects. Reserve margins are expressed as a percentage of peak demand while capacity margins are calculated as a percentage of net capability. According to the staff resource plan, the reserve margin for ERCOT is projected to decline from 35 percent in 1991 to 19 percent in 2001, still providing adequate capacity to meet projected demands. The planned reserve margins provide system reliability by allowing for forced and planned outages of generating units, de-rating of units, differences between projected and actual demand, and other factors. Reserve margins vary among utilities and reliability regions due to different system characteristics (generation mix, planned capacity additions, duration of peak load, outage rate, etc.). As a result, all utilities may not have the same target reserve margins, although all must meet the minimum required by their reliability council.

Lower capacity margins reduce a utility's flexibility in responding to unexpected conditions. One or more of the following conditions could lead to lower-than-expected reserve margins:

1. Higher load growth than projected.
2. Capacity additions not completed or used as scheduled.
3. Large amounts of non-utility generation not completed or ceasing operation.
4. Retrofitting units to meet increased environmental standards.

The reserve margins used by staff to develop the recommended resource plan were based, in part, on utility avoided-cost filings while also considering loss of load probability studies and regional reliability criteria. For most service areas, these reserve margins are essentially the same as those proposed by the utilities. The long-term target reserve margins for HL&P and TU Electric reflect the level of dependence on non-utility generation and the addition of large nuclear units. These factors raise the 15 percent ERCOT minimum reserve margin to 18 percent for these utilities. These reserves are further increased to 20 percent in the first year of each nuclear unit's operation. This insures reliability while the new technology is being introduced and is subject to higher, immature plant forced-outage rates. The staff target reserve margins are included in Table 6.3.

Existing and Near-Term Capability

The level of existing and near-term (unavoidable[3]) capacity must be considered in resource planning. Based on December 1991 Load and Capacity Resource Forecast Filings, utilities in Texas will add 2,458 MW of additional capacity by 1995. Unit 2 of TU Electric's Comanche Peak nuclear power plant, with capacity of 1,150 MW, is included in the list of unavoidable units. Texas-New Mexico put its second unit of TNP One lignite-fired power plant into commercial operation in mid-1992. Despite significant excess capacity, the City Public Service of San Antonio began commercial operation of its J. K. Spruce Unit 1 coal-fired power plant in late 1992. These units are shown in Tables 6.4 and 6.14. A listing of the near-term generating units considered unavoidable by Texas utilities for this report is shown in Table 6.4. **The identification of these units as unavoidable is intended solely for the purposes of this report, and is not intended to prejudge any related proceedings before the Commission.**

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3 "Unavoidable" capacity is capacity under construction or pursuant to a power supply contract which probably could not be canceled for economic or other reasons.

TABLE 6.3
STAFF RECOMMENDED TARGET RESERVE MARGINS
(PERCENT)

YEAR	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	COA	WTU	EPE	BEPC	OTHERS	TEXAS
1991	18.0	20.0	15.3	18.7	15.0	15.0	15.0	15.0	15.0	15.0	22.0	12.9	15.0	17.4
1992	18.0	18.0	15.3	18.2	15.0	15.0	15.0	15.0	15.0	15.0	21.0	13.8	15.0	16.8
1993	20.0	18.0	15.3	17.9	15.0	15.0	15.0	15.0	15.0	15.0	21.0	13.8	15.0	17.5
1994	18.0	18.0	15.3	17.5	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.8
1995	18.0	18.0	15.3	17.1	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.8
1996	18.0	18.0	15.3	16.7	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.7
1997	18.0	18.0	15.3	16.3	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.7
1998	18.0	18.0	15.3	15.9	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.7
1999	18.0	18.0	15.3	15.4	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.6
2000	18.0	18.0	15.3	15.1	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.6
2001	18.0	18.0	15.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.6
2002	18.0	18.0	15.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.6
2003	18.0	18.0	15.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.6
2004	18.0	18.0	15.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.6
2005	18.0	18.0	15.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.6
2006	18.0	18.0	15.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0	20.0	13.8	15.0	16.6

NOTE: Reserves for Texas-New Mexico Power Company (TNP) are provided through standby power contracts with other power suppliers.

TABLE 6.4

UTILITY-REPORTED EXISTING AND NEAR-TERM
GENERATING UNIT ADDITIONS 1992-1995

Year	Utility	Additions [Retirements]		Construction Costs Including AFUDC (000's)	MW	Fuel
1992	CPL	Oklaunion Rerating			2	Coal
	CPS	J K Spruce 1		$571,930	498	Coal
	GSU	Repower Louisiana Station			20	Gas
	GSU	Other			73	Gas
	HL&P	Upgrade			40	Gas
	SPS	Unspecified			10	Gas
	TNP	TNP CFB			149	Lignite
	WTU	Oklaunion Rerating			11	Coal
	WTU	Rerating			4	Gas
			Net Capacity Additions		807	
1993	HL&P	Upgrade			40	Coal
	HL&P	Upgrade			15	Gas
	TUEC	Comanche Peak 2		$4,169,823	1,150	Uranium
			Net Capacity Additions		1,205	
1994	Weatherford	Unspecified			10	Gas
	BEPC	R.W. Miller 4&5		$63,756	208	Gas
	HL&P	Upgrade			55	Gas
			Net Capacity Additions		273	
1995	HL&P	DuPont			158	Gas
	HL&P	Upgrade			15	Gas
	LPL	Trash 1			10	Refuse
			Net Capacity Additions		183	
	1992-1995 Total Net capacity Additions				2,468	MW

Note: Filed by utilities, December 1991. PUCT staff-recommended near-term generating unit additions are listed in Table 6.14.

Planned Capacity

The construction of conventional power plants is still a primary resource alternative for future capacity requirements. Table 6.5 specifies some of the characteristics of the generating units planned between 1996 and 2001 by electric utilities in Texas. These are in addition to the near-term capability specified in Table 6.4. Based on utility filings, an additional 1,699 MW of coal- and lignite-fueled capacity as well as more than 4,500 MW of gas-fueled facilities are planned for 1996 through 2001. As explained later, however, staff is proposing deferral of some of the proposed units.

Conventional Power Plant Capacity With the exception of the nuclear-fuel units, the majority of conventional power plants constructed in recent years have been completed on schedule and close to budgeted cost.

In addition to the high capital cost of constructing new base load capacity, one disadvantage is the time required for planning and constructing a new unit. Initial decisions regarding a new coal or lignite-fueled unit must be made at least five to ten years prior to its scheduled commercial operation date to allow for design, permitting, certification, and construction. Environmental impacts of base load units fueled by coal or lignite represent another disadvantage for this option. Moreover, significant expenditures must be committed to pre-construction activities, and costs can be quite high once a project enters the construction phase. These factors will continue to present a major problem for generation planners during the next several years.

The disadvantages associated with coal- and lignite-fueled base load units, and the uncertainty of recovering the investment in large base load units has been a factor in utilities' decisions to increase reliance on less capital-intensive, small gas units for near-term needs. Combustion turbines provide for flexibility in resource planning and can be constructed at approximately one-third the cost of, and in less than one-half the time required for, constructing a base load coal- or lignite-fueled unit. Combustion turbines provide quick-start capability for meeting system peak demands and emergencies and can be designed and operated in capacity increments which more closely match system load profiles. A number of the planned combustion turbines are configured to permit future conversion to combined-cycle operation.

TABLE 6.5

UTILITY-REPORTED PLANNED GENERATING UNIT
ADDITIONS 1996-2006

Year	Utility	Additions [Retirements]	Construction Costs Including AFUDC (000's)	MW	Fuel
1996	HL&P	Upgrade		15	Gas
	HL&P	Webster 1&2		220	Gas
			Net Capacity Additions	235	
1997	BEPC	Unnamed	$174,363	283	Gas
	GSU	Relicense River Bend		33	Uranium
	TUEC	Twin Oak 1	$1,589,169	750	Lignite
			Net Capacity Additions	1,066	
1998	HL&P	Unknown		219	Gas
	HL&P	Greens Bayou 3,4		220	Gas
	LCRA	Unknown		88	Gas
	TUEC	Twin Oak 2	$926,471	750	Lignite
	WTU	[Abilene 4]		(18)	Gas
	WTU	[Lake Pauline 1]		(19)	Gas
	WTU	[Fort Stockton 2]		(5)	Gas
			Net Capacity Additions	1,235	
1999	CPS	GT 99	$37,038	70	Gas
	GSU	Sabine 4	$500	26	Gas
	GSU	Nelson 3,4	$5,600	58	Gas
	GSU	Willow Glen 4,5	$800	36	Gas
	SPS	Moore County Plant		48	Gas
	TMPA	Unnamed		200	Gas
	TUEC	Undesignated CC		645	Gas
			Net Capacity Additions	1,083	
2000	BEPC	Unnamed		104	Gas
	CPS	GT 00	$77,052	140	Gas
	EPE	Turbine 1	$41,250	80	Gas
	GSU	Neches 8	$2,534	105	Gas
	HL&P	Unknown		412	Gas
	LPL	Combined 1		50	Coal
	SPS	Denver City	$6,324	50	Gas
	TUEC	Undesignated CC		645	Gas
	WTU	Repower Rio Pecos 5		122	Gas
	WTU	[Rio Pecos 4 & 5]		(41)	Gas
	WTU	WTU CC 1	$69,111	114	Gas
			Net Capacity Additions	1,781	
2001	BEPC	Unnamed		104	Gas
	CPL	[Laredo 1]		(36)	Gas
	CPL	Repower Laredo 2	$53,136	89	Gas
	CPS	GT 01	$80,195	140	Gas
	GSU	Willow Glen 3	$4,000	22	Gas
	HL&P	Unknown		206	Gas
	SPS	Refurbish Riverview	$3,065	25	Gas
	SWEPCO	Repower Wilkes 2	$43,732	87	Gas
	SWEPCO	[Lieberman 1&2]		(56)	Gas
	TNP	TNP CFB	$456,543	149	Lignite
	TUEC	Undesignated PSI		290	Gas
			Net Capacity Additions	1,020	

TABLE 6.5
(Continued)
UTILITY-REPORTED PLANNED GENERATING UNIT
ADDITIONS 1996-2006

Year	Utility	Additions [Retirements]	Construction Costs Including AFUDC (000's)	MW	Fuel
2002	BEPC	Unnamed		104	Gas
	CPL	Repower JL	$94,393	163	Gas
	CPS	JK Spruce 2	$763,639	500	Coal
	GSU	Unknown		17	GP*
	HL&P	Unknown		412	Gas
	SWEPCO	Wilkes 3	$43,732	87	Gas
	SWEPCO	[Knox Lee 2&3]		(74)	Gas
	TUEC	[Eagle Mountain]		(115)	Gas
	TUEC	[Parkdale]		(87)	Gas
	TUEC	Undesignated CT		272	Gas
	TUEC	Undesignated CC		620	Gas
	TUEC	[River Crest]		(110)	Gas
	TUEC	Upgrade		31	Gas
	WTU	[Lake Pauline 2]		(27)	Gas
	WTU	WTU CC 2	$69,111	114	Gas
			Net Capacity Additions	1,907	

* Natural gas pressure-drop at Sabine site to provide energy supply.

Year	Utility	Additions [Retirements]	Construction Costs Including AFUDC (000's)	MW	Fuel
2003	COA	Gas Turbine	$37,000	100	Gas
	CPL	SWEPCO Lignite	$785,880	193	Lignite
	HL&P	Unknown		206	Gas
	SWEPCO	SWEPCO Lignite	$785,880	227	Lignite
	SWEPCO	[Lone Star 1]		(50)	Gas
	TUEC	[Mountain Creek 6]		(115)	Gas
	TUEC	Undesignated GS1		660	Lignite
	TUEC	Undesignated CT		272	Gas
	TUEC	[Parkdale 2,3]		(240)	Gas
	WTU	SWEPCO Lignite		82	Lignite
	WTU	[Paint Creek 1]		(35)	Gas
			Net Capacity Additions	1,300	
2004	COA	FB Coal	$568,000	400	Coal
	CPL	Repower LC Hill 1		173	Gas
	CPL	[Victoria]		(45)	Gas
	CPL	[Lon C. Hill 3]		(158)	Gas
	GSU	Neches 4,5,6	$1,067	160	Gas
	HL&P	Unknown		206	Gas
	TUEC	Undesignated CT		272	Gas
	TUEC	Upgrade		16	Gas
			Net Capacity Additions	1,024	
2005	CPL	[La Palma 7]		(47)	Gas
	CPL	JL Bates		(111)	Gas
	CPL	Coleto	$584,046	373	Coal
	CPS	Unnamed	$1,099,116	500	Lignite
	HL&P	Malakoff (1)		645	Lignite
	SWEPCO	Coleto	$584,046	112	Coal
	TUEC	Undesignated GS1		650	Coal
	WTU	Coleto	$584,046	140	Coal
	WTU	[Paint Creek 2&3]		(85)	Gas
			Net Capacity Additions	2,177	

TABLE 6.5
(Continued)
UTILITY-REPORTED PLANNED GENERATING UNIT
ADDITIONS 1996-2006

Year	Utility	Additions [Retirements]	Construction Costs Including AFUDC (000's)	MW	Fuel
2006	CPS	Unspecified		(100)	Gas
	EPE	Turbine 2	$45,600	80	Gas
	SWEPCO	[Lieberman 3&4]		(220)	Gas
	SWEPCO	[Knox Lee 4]		(83)	Gas
	SWEPCO	SWEPCO CC	$105,861	218	Gas
	SWEPCO	SWEPCO CT	$61,760	146	Gas
	TUEC	Undesignated CT		242	Gas
	WTU	WTU CC 3	$69,111	114	Gas
			Net Capacity Additions	397	
	1996-2006 Total Net capacity Additions			13,225	MW

Note: Based on resource plans filed by utilities in December 1991.

The plan filed by TU Electric (in April 1992) did not cover the period 2002-2006. Hence, staff estimated TU's plan addition/retirement dates using the utility's plans filed in December 1991 (original) and in April 1992 (revised).

PUCT staff-recommended near-term and planned generating unit additions are listed in Table 6.16.

Capacity shown for Coleto Creek and SWEPCO lignite indicate that utility's share of the unit.

Nuclear Power Plant Capacity

The integration of nuclear power plants into the generation mix and rate bases of regulated utilities has generated much controversy--to the extent that some utilities see regulatory treatment as a threat to financial viability. The unforeseen increases in construction costs and unrealized expectations for nuclear power plants have caused plant cancellations, stretched-out construction schedules, and outright abandonments. The existing and committed nuclear plants in Texas are not exempt from the criticisms surrounding Brown's Ferry, Three Mile Island (TMI), or foreign plants. These pressures have contributed to increased regulation, more attention to safety concerns, unplanned construction costs, and lengthy construction delays.

Compared to many other states, Texas is a relative newcomer in the field of nuclear power plant regulation. Predicting the reliability and efficiency of Texas plants without the benefit of first-hand experience presents a challenge. Although much information can be derived from other states, each nuclear unit is different. Before comparisons with similar nuclear plants can be made, new units must first reach mature status. In general, this means about three years of operation and at least two complete refueling cycles. In recognition of the potential reliability problems with immature units, primary owners are permitted to increase their planning reserve levels to compensate during the immaturity period.

TU Electric's Comanche Peak Unit 2 is the only nuclear unit under construction in Texas. Commercial operation is expected in the summer of 1993. The completion of this unit will add 1,150 MW of capacity and increase the amount of nuclear capacity serving Texas customers to 5,570 MW by 1993. Nuclear units and their total capacities are listed below:

River Bend, Unit 1, 940 MW. (Estimated Texas portion for GSU: 293 MW by 1993)

Palo Verde Nuclear Generating Station, Units 1, 2, And 3, 1,270 MW each. (Estimated Texas portion for EPE: 477 MW by 1993)

South Texas Nuclear Project, Units 1 And 2, 1,250 MW each. (HL&P: 770; CPL: 630; CPS: 700; and COA: 400 MW by 1993)

Comanche Peak Steam Electric Station, Units 1 And 2, 1,150 MW each. (TU Electric: 2,300 MW by 1993)

Unit Life Extension and Efficiency Improvements

The life extension and efficiency improvements of generation units are reported in the utility-controlled (supply-side) section of the energy efficiency filings. An overview of these programs shows that the most frequently filed option concerns power plant programs. Figure 6.1 illustrates that the greatest losses, hence the greatest opportunity for improvements, is in the power plant area.

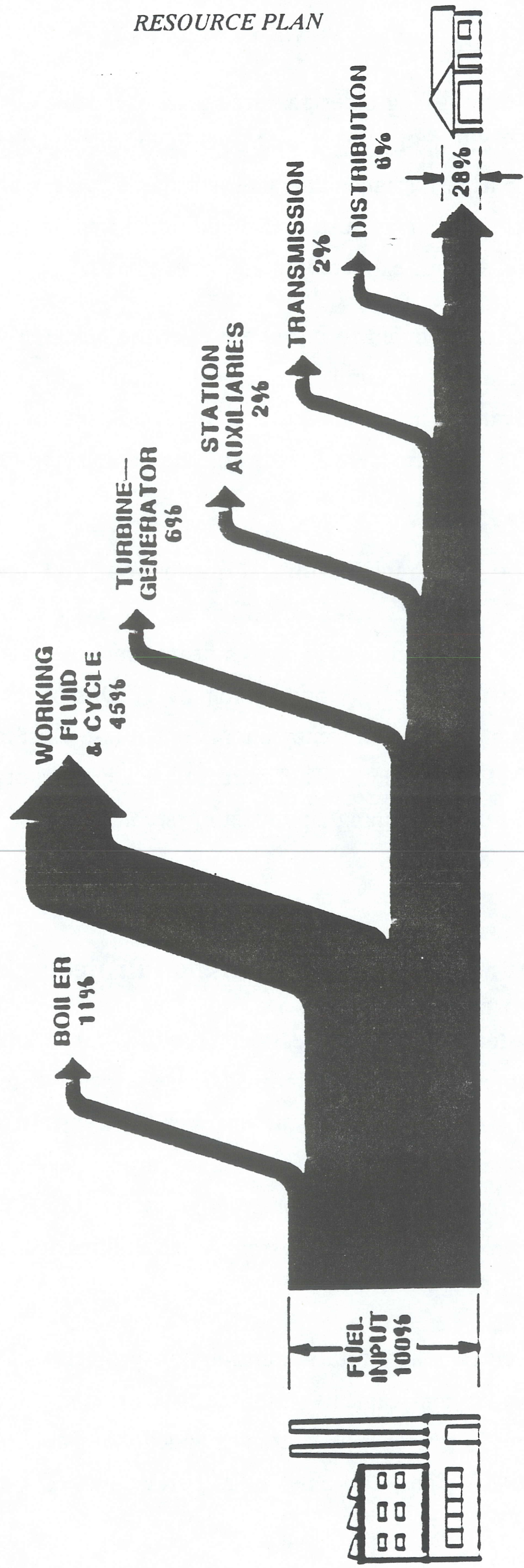
Usually, close to two-thirds of the fuel energy used by utilities to produce electricity is lost by the time it reaches the consumer. Improving power plant efficiencies and reducing system losses represent a large potential for savings, but quantifying the magnitude of potential savings is difficult. Staff reviewed the utility-reported effects of energy efficiency and life extension improvements and incorporated the utility filings into the resource plan.

Staff encourages utilities to reevaluate their existing generating and transmission capabilities and through unit life extension and efficiency improvements to maximize the use of this less-expensive option in meeting future capacity needs. This may require additional studies and analyses to determine the viability of life extension, the cost involved, and the value those life-extended units can provide to the generating system relative to other resource options.

Generation Units Extending the life of generating units is a potentially significant option for expanding generation supply during the next ten years. This option has received considerable attention by utilities over the last few years primarily because of the financial risk associated with constructing new base load power plants. Much research has been conducted to evaluate cost-effective methods of extending generating unit life. By replacing key boiler and turbine components, adding new plant control and diagnostic systems, and initiating improved maintenance practices, the availability and efficiency of older generating units can be vastly improved while extending their operating lives by 20 years or more. The costs associated with life extension programs are dependent on various unit-specific factors but are estimated to range between 20 to 50 percent of new plant construction costs. Modification can be completed in one to two years as opposed to the four to six years required to construct a conventional base load power plant.

FIGURE 6.1

TYPICAL ENERGY LOSSES FROM UTILITY TO CONSUMER



Repowering and refurbishing older gas-fired units are viable options considered by electric utilities such as HL&P, CPL, WTU, and SWEPCO for the coming decade. However, the much more efficient performance characteristics associated with the advanced technology of combined cycle units may justify the additional capital outlay for new construction because of the fuel savings expected on a life cycle basis.

Gas-fueled capacity scheduled to be retired over the next ten years could be a source of capacity, particularly if natural gas costs continue to remain relatively low and technological advances in evaluating and applying this option continue to be made. Utilities such as TU Electric have already considered delaying retirement dates for some of their gas units.

Transmission and Distribution

Transmission and distribution (T&D) facilities offer opportunities for increased efficiency of system operation. T&D systems account for a significant amount of the total energy lost in the provision of electric service. Optimization of T&D systems can reduce these losses. Opportunities for significant efficiency improvement also exist in the replacement of older, less efficient T&D equipment. The increased availability of economical software and hardware capable of performing optimization studies enables a better analysis of T&D systems.

Current and Future Transmission Projects

Transmission system reliability assessment requires large amounts of information and sophisticated computer models. Because these expensive resources are not currently available to the staff for independent analyses of transmission needs, each project is evaluated individually in the CCN process. During 1992, 19 CCN applications were approved. The majority of new construction is for 138-KV lines with 345-KV lines second. As shown in Figure 6.2, investor-owned utilities account for over one-half of the CCN approvals in 1992.

Information on current and future transmission projects is obtained from the utilities' December 1991 load and capacity resource forecast filings. A summary of utility-filed transmission projects for ten or more miles appears in Table 6.6., totaling approximately 913 miles of 345-KV lines, 240 miles of 230 -KV lines, 974 miles of 138-KV lines, 114

FIGURE 6.2

TRANSMISSION LINES APPROVED

JAN. - DEC. 1992

	345KV		230KV		138KV		115KV		69KV			
	Miles	No. of Dkts.	Miles	No. of Dkts.	Miles	No. of Dkts.	Miles	No. of Dkts.	Miles	No. of Dkts.	Total Miles	No. of Dkts.
IOU	81.4	2	3.6	1	80	9	0	0	0.5	1	165.5	13
COOP	0	0	0	0	22.2	2	0	0	23.7	4	45.9	6
Total	81.4	2	3.6	1	102.2	11	0	0	24.2	5	211.4	19

	<5 Miles	6-10 Miles	11-20 Miles	35 Miles	78 Miles
Number of Dockets	10	2	5	1	1

TABLE 6.6

MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
Greater than 10 Miles in Length
including substation costs

Project Name		Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
TU Electric									
	Interconnection Projects:								
	Comanche Peak-Benbrook	Somervill, Hood, Johnson, Parker, Tarrant	345	AC	40.7	$5,450,300	*	Jan-92	Dec-92
	Permian Basin-Barilla (WTU)	Ward	138	AC	16.4	$1,578,290	*	Feb-92	May-92
	S. Mineral Wells-W. Weatherford	Palo Pinto, Parker	138	AC	17.3	$2,965,000	*	May-92	May-93
	Oran-R. W. Miller (BEPC)	Palo Pinto	138	AC	20.0	$3,677,000	*	May-93	May-94
	Welsh-Monticello HVDC East Tie	Titus	345	AC/DC	0	$18,369,000	***	Jan-93	Dec-98
	Tarrant W.-Hilltop (BEPC)	Parker	138	AC	10.0	NYD		May-98	May-99
	Limestone (HLP)-Watermill	Freestone, Ellis, Dallas, Navarro, Limestone	345	AC	179.6	$78,891,000	*	Jan-98	Nov-99
	Within Service Area:								
		25 Additional substation projects							
		24 Additional line uprgrade projects							
		34 Additional new transmission line projects							
HL&P									
	Welsh-Monticello HVDC East Tie	Titus	345	AC/DC	0	$33,536,000	***	Jan-93	Dec-98
	Salem-Zenith	Austin, Harris, Walker, Washington	345	AC	92.0	$170,400,000	*	Jan-01	Dec-04
	Salem-Zenith-Twin Oak	Burleson, Lee, Milam, Robertson, Washington	345	AC	175.0	$239,400,000	*	Jan-01	Dec-04
GSU									
	Line 88	Jefferson	138	AC	12.6	$2,070,000	**	Oct-94	Jun-95
	Line 197	Newton, Orange	230	AC	25.0	$4,960,000	**	Jun-97	Jun-98
	Line 415	Polk	138	AC	12.0	$2,050,000	**	Oct-96	Nov-97
CPL									

RESOURCE PLAN

TABLE 6.6

(Continued)

MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS

Greater than 10 Miles in Length

including substation costs

Project Name		Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
	Edinburg-Rio Hondo	Hidalgo, Cameron	345	AC	40.5	$28,157,000	*	May-92	May-93
	Lonhill-Coleto	Nueces, Goliad, Bee, San Patricio	345	AC	78.0	$43,838,000	*	Apr-93	Apr-94
	Dilley Switching-Wormser	Frio, LaSalle, Webb	138	AC	82.0	$17,259,000	*	May-93	May-94
	Welch-Monticello HVDC East Tie	Titus	345	AC/DC	0.0	$39,029,000	***	Mar-95	Mar-98
	W. Batesville-Eagle Pass	Maverick, Zavala	138	AC	55.0	$12,896,000	*	May-97	May-98
CPS									
	Green Mountain-Stone Gate	Bexar	138	AC	10.1	$4,465,328	*	Jan-98	May-98
	Stone Gate-Hill Country	Bexar	138	AC	10.4	$4,465,328	*	Jan-98	May-98
	Cagnon-Scenic Hill	Bexar	138	AC	23.2	$6,410,093	*	Jan-99	May-99
	Bandera-Cagnon	Bexar	138	AC	11.4	$1,447,272	*	Mar-99	May-99
	Hill Country-Cagnon	Bexar	345	AC	19.5	$8,129,012	*	Feb-00	May-00
	MM Lignite-Gideon (2)	Bexar	345	AC	13.0	$21,213,570	*	Jan-03	May-03
	Cagnon-Kendall	Bexar	345	AC	44.0	$9,859,238	*	Feb-03	May-03
	Hill Country-Skyline	Bexar	345	AC	11.0	$5,178,921	*	Mar-03	May-03
	Spruce Loop	Bexar	345	AC	17.0	$7,261,338	*	Feb-05	May-05
SPS									
	Terry-Sulphur Springs	Terry	115	AC	28.0	$5,327,000	*	Feb-92	May-92
	Plant X-Tolk-Sundown	Lamb	230	AC	10.0	$2,009,000	*	Jun-92	Dec-92
	Jones-Grassland	Lubbock, Lynn	230	AC	28.0	$5,167,000	*	Jan-93	Jun-93
	Grassland-Borden	Lynn, Borden	230	AC	44.0	$7,410,000	*	Jan-93	Jun-93
	Lea County-Midland	Lea NM, Gaines & Andrews TX	230	AC	94.0	$12,327,000	*	Jan-93	Jun-93
	Seagraves-Sulphur Springs	Terry	115	AC	11.0	$1,523,000	*	May-93	Sep-93
	Lynn-Graham	Lynn, Garza	115	AC	23.5	$4,195,000	*	Jun-93	Dec-93
	Lamb-Carlisle	Lamb, Hockley, Lubbock	230	AC	39.0	$5,220,000	*	Nov-93	Apr-94

TABLE 6.6
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
Greater than 10 Miles in Length
including substation costs

Project Name		Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
	Tolk-Tuco	Bailey, Lamb, Hale	345	AC	55.0	$12,310,000	*	Oct-94	Jun-95
SWEPCO									
	Knox Lee- Overton	Rusk	138	AC	23.8	$2,700,000	**	Jan-91	Dec-92
	Rock Hill- S. Shreveport	Panola TX Caddo LA	138	AC	44.8	$1,655,000	*	Jan-92	Dec-92
	Gilmer-Purdue	Upshur	69	AC	11.4	$1,068,000	**	Feb-93	Jun-93
	Bann- S.E. Texarkana	Bowie	138	AC	12.4	$3,676,000	**	Jan-93	Dec-93
	Grand Saline- N. Mineola	Smith, VanZandt, Wood	138	AC	16.5	$2,730,000	*	Jan-93	Dec-93
	N.W. Henderson- Overton	Rusk, Smith	138	AC	13.1	$3,720,000	*	Jan-93	Dec-94
	Marshall- Rock Hill	Harrison, Panola	69	AC	17.7	$1,446,000	**	Jan-94	Dec-95
	Rock Hill- S.W. Shreveport	Panola TX Caddo LA	345	AC	38.0	$20,332,000	*	Jan-94	Dec-96
	Karnack- Woodlawn	Harrison	69	AC	11.3	$605,000	**	Jan-96	Dec-96
	Beckville- N.W. Henderson	Rusk, Panola	69	AC	26.7	$1,761,000	**	Jan-95	Dec-97
	Pittsburg- Winnsboro	Camp, Franklin, Wood	138	AC	19.9	$4,714,000	*	Jan-96	Dec-97
	Longwood- S.E. Marshall	Harrison	138	AC	22.2	$1,439,000	**	Jan-97	Dec-97
	Welsh- Monticello HVDC East Tie	Titus	345	AC/ DC	16.0	$39,798,000	*	Jan-93	Dec-98
	Knox Lee- Rock Hill	Rusk, Panola	138	AC	10.0	$707,000	**	Jan-99	Dec-99
	Jefferson- Lieberman	Marion	138	AC	28.1	$1,979,000	*	Jan-99	Dec-99
	Quitman- Winnsboro	Wood	138	AC	15.7	$3,784,000	*	Jan-99	Dec-00
	Jefferson- North Marshall	Harrision, Marion	69	AC	13.6	$982,000	**	Jan-00	Dec-01
	Jefferson- Superior	Marion	69	AC	21.7	$1,600,000	**	Jan-01	Dec-01
LCRA									
	Colorado Substation- Nada (50% w/ STEC-MEC)	Colorado	69	AC	19.4	$3,018,000	**	Mar-91	Jun-92

TABLE 6.6
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
Greater than 10 Miles in Length
including substation costs

Project Name		Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
	McNeil-Gabriel	Travis, Williamson	138	AC	21.0	$5,269,000	**	NYD	Jun-94
	Wolf Lane-Buda Area	Bastrop, Hays, Travis, Caldwell	138	AC	27.0	$5,428,000	**	NYD	Jun-95
	Fayetteville-Salem	Fayette, Washington	69	AC	21.0	$2,705,000	**	Jun-95	Jun-96
COA									
	Line 987	Caldwell, Travis	138	AC	17.0	$22,314,950	*	NYD	Jun-94
	Garfield-Hicross	Travis	138	AC	14.0	$4,200,000	**	NYD	Jun-95
	Line 922	Travis	138	AC	27.0	NYD		NYD	Jun-99
	Austrop-McNeil	Travis	138	AC	18.0	NYD		NYD	NYD
WTU									
	Barilla-TU Electric Tie	Ward, Pecos, Reeves	138	AC	35.6	$3,295,467	*	Dec-91	Jun-92
	Menard-Sonora	Menard, Schleicher, Sutton	138	AC	59.3	$4,847,000	*	Jun-93	Jun-94
	Abilene Mulberry-San Angelo Red Creek	Tom Green, Coke, Nolan, Taylor, Jones	345	AC	87.1	$23,741,000	*	Jun-96	Jun-97
	Lake Pauline-S.W. Vernon	Hardeman, Wilbarger	138	AC	28.5	$2,781,000	*	Jun-97	Jun-98
	E. Munday-Rule	Knox, Haskell	138	AC	30.0	$3,802,000	*	Jun-97	Jun-98
	Abilene South-Tuscola	Taylor	138	AC	11.0	$2,524,000	*	Jun-97	Jun-98
	Alpine-Presidio	Brewster, Presidio	69	AC	73.4	$5,101,000	*	Jun-99	Jun-00
	Lake Pauline- West Childress	Hardeman, Childress	138	AC	37.2	$4,085,000	*	Jun-00	Jun-01
	Alpine- Ft. Davis	Brewster, Jeff Davis	69	AC	28.5	$1,354,000	*	Jun-00	Jun-01
EPE									
	Santa Theresa Substation/ Diablo-Santa Teresa	Dona Ana NM	115	AC	11.4	$1,916,950	*	Nov-91	Apr-93
	Anthony-Montoya	Dona Ana NM	115	AC	10.2	$928,385	**	Jul-92	May-93
	Felipe Substation/ Horizon-Felipe	El Paso TX	115	AC	12.0	$1,829,000	*	Feb-94	May-95
	Salopec-Anthony	Dona Ana NM	115	AC	17.5	$1,597,771	**	Oct-95	Jun-96

TABLE 6.6
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
Greater than 10 Miles in Length
including substation costs

Project Name		Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
	P.O.E. Switching Station/ P.O.E.-Newman	El Paso TX	345	AC	47.0	$8,570,491	*	Jun-95	Mar-97
TNP									
	Clifton-Walnut Springs	Bosque	138	AC	26.3	$4,471,000	*	Jan-99	Jun-99
BEPC									
	Reno-Rhome	Parker, Wise	69	AC	14.4	$4,238,500	**	Feb-92	Jun-92
	Miller-Stephenville	Erath, Palo Pinto	138	AC	33.7	$2,884,350	*	Feb-92	Jun-92
	Miller-Fox	Parker, Palo Pinto	138	AC	29.4	$2,677,050	*	Feb-93	Jun-93
	Windsor S.W.-Gatesville	McLennan, Coryell	138	AC	20.0	$7,541,650	*	Jan-94	Jun-94
	Whitney-Rogers Hill	Hill, McLennan	138	AC	14.0	$1,034,450	*	Jan-94	Jun-94
	Spunky-Concord	Johnson	138	AC	10.8	$1,712,700	**	Feb-94	Jun-94
	Emmett-Richland	Navarro, Ellis, Hill	69	AC	20.0	$5,296,900	*	Feb-94	Jun-94
	Wilkerson-Roanoke	Denton	138	AC	14.0	$24,353,200	*	Feb-96	Jun-96
STEC-MEC									
	Nada-Sheridan (50% w/ LCRA)	Colorado	69	AC	19.4	$2,380,000	*	May-91	Jun-92

Notes:		
	*	Combined Line and related Substation costs.
	**	Line Cost only; no substation cost involved.
	***	Substation Cost only; no line cost involved.
	NYD	Not yet determined.

miles of 115-KV lines, and 299 miles of 69-KV lines. A complete list of utility-filed transmission projects is included in the Technical Appendices.

Construction costs for these projects are estimated to exceed $600 million during the next decade. Two major transmission projects by HL&P with an estimated cost of over $400 million, are expected after 2001. On average, 69-KV and 115-KV lines cost about $100 thousand per mile. For 138-KV and 230-KV lines, the average cost is between $150 to $200 thousand per mile. For 345-KV lines the cost is between $650 to $750 thousand per mile.

East HVDC Tie A high voltage direct current (HVDC) tie between ERCOT and SPP, known as the "East Tie" has been approved for service in 1995. The four participants are SWEPCO, CPL, TU Electric, and HL&P. The "East Tie" requires FERC and PUCT approval. In its intervention in the FERC case, the PUCT recognized FERC's authority to determine the need for the interconnection facilities but reserved its own authority to evaluate the issues arising from the siting of the conversion facilities and transmission lines. The substitution of this "East Tie" for the "South Tie" originally ordered was approved by FERC. PUCT approval under PURA Section 54 certifies the second ERCOT and SPP interconnection ordered by FERC.

This second ERCOT-SPP asynchronous interconnection (the "North Tie" has been completed) is planned for emergency assistance between the two reliability councils; improve the reliability of the applicant companies and the two reliability councils; to facilitate non-emergency exchanges of power and energy between and among applicants and other systems in ERCOT and SPP; and, as further found by FERC in [Order] EL79-8, to encourage overall conservation of energy and capital and optimize the use of facilities and resources.

The four elements of this major project are:

- a 16.5 mile single circuit "Welsh-Monticello" 345-KV alternating current (AC) transmission line to be constructed by SWEPCO, in Titus County.
- 345-KV AC switchyard additions by TU Electric at the Monticello-generating plant.
- 345-KV switchyard additions by SWEPCO at its Welsh steam electric station.

- a high-voltage direct (HVDC) 600-MW back-to-back converter station also to be built at Welsh but on land owned by the joint-venture partners as tenants in common.

Ownership and cost responsibilities for the project are:

• CPL	150MW	25%
• SWEPCO	150MW	25%
• HL&P	200MW	33-1/3%
• TU Electric	100MW	16-2/3%

The construction costs of the project, without inclusion of any of the replaced South Tie planning costs, are estimated at approximately $110,477,000 in the Joint Stipulation of the parties.

Security of Fuel Supply

Because of the variability in fuel prices and availability, generating utilities assign a high priority to fuel supply security as shown by the amount of fuel committed under long-term contracts. The percentage of generating fuel currently committed to contract and the overall targets for contract purchases were submitted in the utilities' responses to requests 8.03 through 8.09 of the 1991 forecast filing. The responses indicate that the utilities will continue to maintain some flexibility in future supply mix. However, flexibility in procurement and generation is constrained if the percentage of a particular fuel or fuel source already committed to purchase is too high. Likewise, currently contracted amounts decline as contracts expire.

Contracts reduce the uncertainty of fuel supplies. Many Texas utilities have contracted for virtually 100 percent of the coal for base load, coal-fired stations. However, some spot coal purchases are made when supplemental quantities are required. Currently, all lignite plants in Texas are located adjacent to the mines which supply their fuel. At coal and lignite generating plants, fuel stockpiles provide an additional hedge against short-term fuel supply disruptions.

Natural gas supplies are available now in more than adequate quantities and at a relatively low price. Reserves can be replaced at modest increases in price. Natural gas is touted as the future fuel of choice because of its clean-burning characteristics.

The security of nuclear fuel supplies requires a much different approach. Whereas fossil fuel plants require a continuous feed of fuel, nuclear power plants operate in a batch mode. Fuel is loaded, then consumed over one to two years -- after which time the reaction is stopped, the spent fuel removed, a fresh batch of fuel loaded, and the cycle started again. Because nuclear power plants do not require a continuous input of fuel into the reactor and the fuel loaded into the reactor lasts for at least one year, nuclear power plants are not generally subject to short-term supply disruptions. Because a long lead time and many processing steps are required to convert milled uranium ore into fabricated fuel bundles, utilities must plan fuel bundle manufacture and delivery very carefully. A delay at any step in the manufacturing process can result in a lack of fresh fuel at the time of reload.

Some utilities have developed their own captive fuel resources, notably utility-owned lignite reserves and some minor, utility-owned gas producing wells. However, only TU Electric (through its Texas Utilities Mining Company subsidiary) has successfully operated large-scale fuel-production facilities. TU Electric's lignite mining operations make it one of the largest coal and lignite producers in the nation.

Through effective contracting, fuel diversification, and sound inventory practices, utilities in Texas should be relatively immune from severe disruption of fuel for their plants. No physical reasons exist for long-term interruption of their fuel supply; however, rail or mine strikes as well as short-term natural gas curtailments are always possible.

Texas Cogeneration Industry

Cogeneration is a significant source of electric energy in Texas. A cogeneration facility is defined by FERC rules as equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial or commercial heating or cooling purposes by the sequential use of the energy. In recent years, most industrial cogeneration in Texas has been produced by units granted Qualifying Facility (QF) status, a certificate awarded under enactment of the federal Public Utility Regulatory Policies Act of 1978 (PURPA). Under Texas law, such federally-certificated QFs are generally excluded from public utility status and the regulatory overview of the PUCT. As shown in Table 6.7, there is, as of December 1991, some 7,360 MW of cogenerated capacity in the state, with an additional 557 MW under construction. Approximately 10 percent of the MWH generated in the state in 1991 was supplied by cogenerators. (See Figure 6.3.)

TABLE 6.7

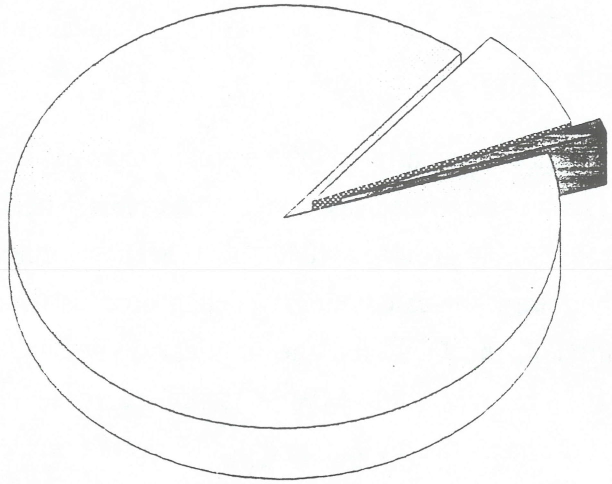
COGENERATION AND SMALL POWER PRODUCTION IN TEXAS
BY SERVICE AREA
STATUS OF PROJECTS. AS OF 1992

UTILITY SERVICE AREA	EXISTING CAPACITY (MW)	UNDER CONSTRUCTION (MW)	PROPOSED (MW)	IDLE (MW)
COA	109.7	1.0		
CPL	641.1	479.5	340.0	
EPE	20.3			
GSU	657.9		8.0	
HL&P	4,121.2	34.2		3.9
MUNI	38.5		7.5	
SPS	108.2			
SWEPCO	128.3			
TNP	723.7	42.0	20.0	
TU	806.0			
WTU	5.0			
TOTAL	7,359.9	556.7	375.5	

NOTE: The total capacity given in this table represents an increase of 242.7 MW, or 3.41 percent over the previous Load Forecast Report total of 7,117.2 MW.

FIGURE 6.3

STATEWIDE GENERATION MIX
1991 MEGAWATT-HOURS



☐ 1 - Firm Cogen 8.2%   ■ 2 - Non-Firm Cogen 1.2%   ☐ 3 - Generation and Purchases 90.6%

Cogeneration in Texas is primarily gas-fired turbines. (See Figure 6.4.) The historical trend of cogeneration activities in Texas is presented in Figure 6.5.

Most industrial cogeneration is concentrated in a relatively small area in and around the City of Houston, in the service areas of HL&P and TNP. Most of the cogenerated power is associated with petrochemical industries. The seven biggest projects account for almost one half of the total amount cogenerated in Texas. Indeed, the largest cogenerator, Dow Chemical Company with over 1,300 MW, would be the eleventh largest generating utility in Texas if it had utility status.

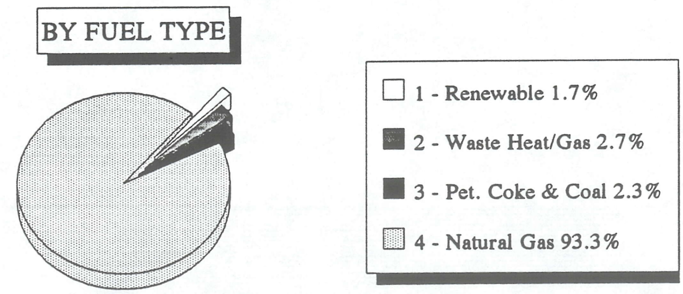
With so much cogeneration concentrated in one area, Texas has had to face the problem of wheeling. Briefly, Commission rules say that utilities must wheel power from the QF to another utility if requested, provided that the wheeling utility has the transmission capacity. The methodology for calculating wheeling costs is the result of a compromise between the Commission, the QFs, and the utilities. Wheeling of electricity from QFs grew from zero in 1986 to over 1,800 MW in 1988 before declining to 1,537 MW at the end of 1991. Table 6.8 shows the amount and destination of this wheeled power.

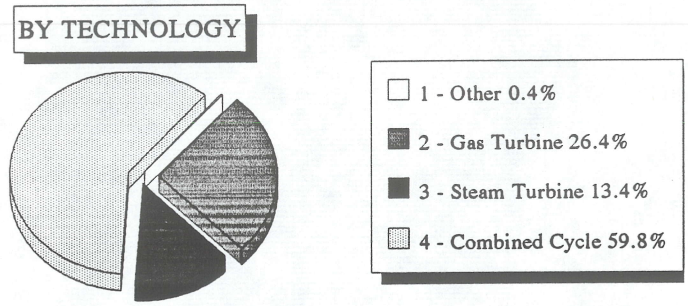
Cogeneration Policy The current cogeneration policy in Texas, as established by the Texas Legislature and by the Substantive Rules of the PUCT, is aimed at securing all reliable cogeneration available at prices lower than planned utility generation projects. The price for cogeneration is set by competitive negotiations between a utility and a cogenerator with an upper limit set by that utility's avoided costs. The avoided costs are established in proceedings before the Commission and are based on the cost of a generating unit that can be displaced or deferred by firm capacity from QFs. The intent of this policy is to allow the market to determine the value and, in turn, the amount of cogeneration that will exist in Texas.

The Commission is the informal mediator of QF and utility disputes and the formal arbiter if disagreements cannot be resolved by the parties. As a result, rates are generally determined through negotiations between the utility and the cogenerator and set out in a confidential contract rather than an approved tariff. This reliance on the market has been successful and has resulted in a better response to the dynamic cogeneration market than would a more structured regulatory procedure. This picture may change over the next few years when the current surplus capacity is eliminated. More and more cogenerators are interested in entering into long-term contracts.

FIGURE 6.4

COGENERATION & SMALL POWER PRODUCTION IN TEXAS
(7,360 MW) AS OF DECEMBER, 1991





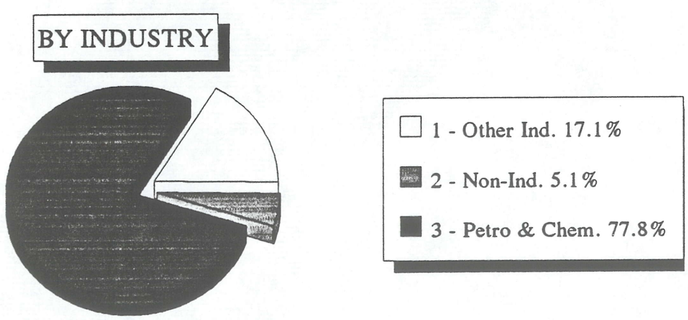


FIGURE 6.5
TRENDS IN COGENERATION

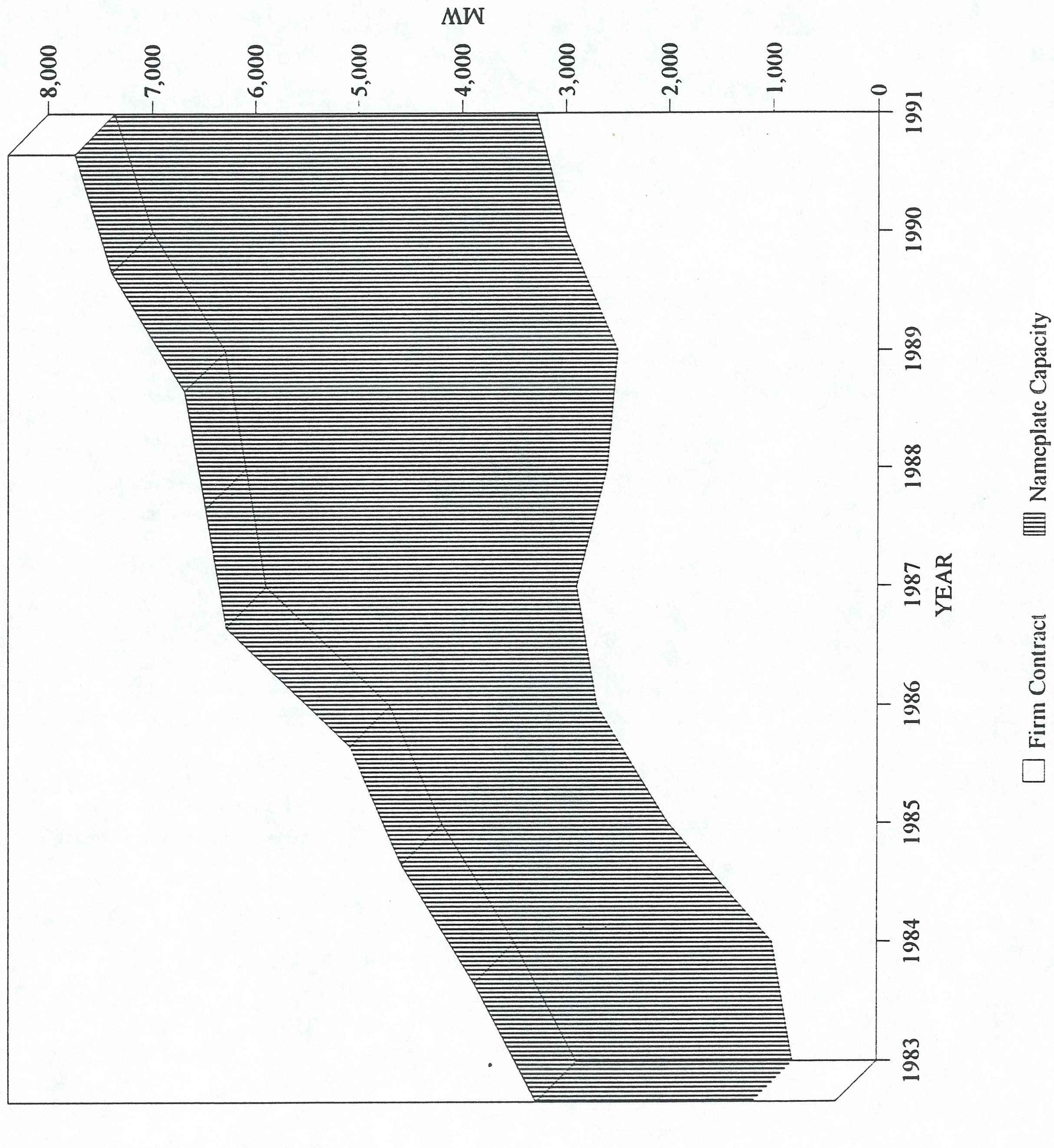


TABLE 6.8

COGENERATION UTILITIZING HL&P AND TNP WHEELING SERVICES

COGENERATOR	PURCHASING UTILITY	CONTRACT CAPACITY (MW)
CLEAR LAKE COGEN	TNP	300
COGEN LYONDELL	TU ELECTRIC	400
COGENRON	TU ELECTRIC	410
DOW CHEMICAL	TU ELECTRIC	350
TEXASGULF CHEMICALS	TU ELECTRIC	77
TOTAL		1,537

A current avoided cost proceeding (Docket No. 10921 for BEPC's avoided cost) could not be settled through negotiation and has gone to hearing. HL&P's avoided cost filing, Docket No. 10832, is also expected to go to hearing.

Future of Cogeneration in Texas

The development of cogeneration will continue to depend on the economic health of the petrochemical industry, stable fuel costs, future electricity prices, and the need for additional generation capacity. Manufacturing industries are the main source of cogeneration among all economic sectors. Even though some potential exists for on-site electricity generation in other economic sectors, the amount is insignificant in comparison to the potential of the manufacturing sector. Potential cogenerators among manufacturing industries include process-type industries such as paper, chemicals and allied products, petroleum, stone, clay, and glass, and primary metal. These industries, along with food and kindred products, and textile mill products, account for most of the potential cogeneration within the manufacturing sector.

Texas is still facing excess generating capacity. As a result, cogenerators have difficulty selling capacity to utilities on a firm basis. However, demand is increasing and utilities are not anticipating significant new capacity additions during the mid-1990s. This will result in a decline in excess capacity and greater reliance on cogeneration during the second half of the 1990s. HL&P, as an example, entered into two new contracts with cogenerators for 320 MW of capacity to serve its system needs between 1995 and 2005. The information filed by the electric utilities suggests five trends in Texas cogeneration discussed below.

Declining Capacity Needs. The first trend is the decrease in capacity additions. The major reasons are (1) slower projected growth in demand for electricity, (2) extended life of existing power plants, and (3) more efficient electricity use. As a result, lower projected capacity is required. This, coupled with the large amount of cogeneration in Texas, has led and will probably continue to lead to competitive contract terms and lower capacity payments to the cogenerators. Such conditions are expected to persist into the future.

Industry Maturation. A maturing cogeneration industry in Texas is evident from ownership patterns. Most cogeneration is owned by large, well-financed companies and not by small entrepreneurs. These companies are typically subsidiaries of even larger companies.

As utility and cogenerator experience grows, the contract terms that have evolved are also good evidence of a maturing industry. The first Standard Terms and Conditions filed by the utilities did not address many of the areas that are covered today. Today's more detailed contracts contain many items that both utilities and cogenerators have learned are important.

Regulatory Changes. Policies and rules for cogenerators are changing. In fact, the impact of the recently signed National Energy Policy Act of 1992 on Texas has not yet been determined. Actions that will be taken by FERC in the near future will ultimately affect the level of cogeneration and independent power production in Texas.

Much of the success of cogeneration in Texas is attributable to the multi-faceted character of the current policies and rules which have changed slowly and responsively. The impacts of the National Energy Policy Act will determine whether the past success will continue into the future.

Increased Competition. Cogenerators in Texas will probably face increasing competition. The National Energy Policy Act is intended to increase competition at the generation level. A principal factor in this Act is the exemption of wholesale generators from the Public Utility Holding Company Act, thus creating potential competitors with utilities.

In addition, the competition for diminishing capacity needs will come not only from other QFs and independent power producers but also from utilities. Recently, we have seen joint venture power plant projects between utilities and industrial customers. A good example is HL&P's pending CCN (Docket No. 11000) for a 158-MW cogeneration facility to sell steam as a byproduct to Du Pont Industrial Complex. These types of activities will result in more competition in the near future.

Industrial Composition. Cogeneration projects are beginning to spread more across the state. Under current conditions, most of the future cogeneration is planned for areas other than the Gulf Coast. There are two main reasons for this shift away from the Gulf Coast. First, HL&P has all the cogeneration it needs for several years and is not paying capacity payments for any additional cogeneration. Second, the transmission lines used to wheel power out of the Houston area are reaching their limits. However, the implications of the National Energy Policy Act may significantly alter this picture.

Cogeneration Forecast The cogeneration forecasts made by each utility were reviewed and adjusted to fit the staff demand forecast. The overall picture that emerges from both forecasts is that nearly all firm cogeneration will continue to be purchased by HL&P and TU Electric. Commission staff's recommended cogeneration levels for the 13 major service areas appear in Table 6.9. More detailed analyses for HL&P, TU Electric, and TNP follow.

HL&P. When the staff demand forecasts are used, the reserve margins for HL&P still remain very high through the first half of the 1990s. For this reason, staff agrees with HL&P's cogeneration forecast for the period 1992 through 1995. From 1996 through 2001, the staff projects a higher demand. If demand reaches staff-projected levels, it is unlikely that HL&P will completely eliminate its reliance on cogenerated power in 1995 and beyond. It is more likely that either the contracts for existing cogenerated power will be renewed or new cogenerators will take their place. The staff's cogeneration projections for HL&P are shown in Table 6.10. Given the staff's recommendation, about nine percent of HL&P's net system capacity in the year 2001 is anticipated to come from cogeneration.

TU Electric. The TU Electric cogeneration forecast appears very conservative in view of their capacity requirements. The company started with its known contracts, amounts, and expiration dates, which result in a 616 MW decline in cogeneration purchases by the year 2001 and even greater reductions in later years. However, cogeneration, along with other capacity options, are listed as other net purchases, termed "unspecified resources". These unspecified resources could be made up of cogeneration, conservation and load management programs, new power stations, or purchased power. The staff also started with the known contracts but attempted to "sort out" how much of the unspecified resources could probably come from cogeneration. The following assumptions were made:

1. Cogeneration growth within TU Electric's service area will continue to be slow because of a lack of large steam-using industries within their area.
2. Most of TU Electric's cogeneration will continue to be wheeled from the Houston area. This is very likely because of the continued lack of a market in the Houston area coupled with the concentration of potential cogeneration.
3. Transmission ties will limit transfers to TU Electric from the Houston area unless planned transmission capacity additions are completed on schedule.

TABLE 6.9

STAFF RECOMMENDED COGENERATION PURCHASES

YEAR	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	COA	WTU	EPE	TNP	BEPC	TMPA	TOTAL
1991	1,921	945	5	0	0	0	0	0	0	0	0	335	0	0	3,206
1992	1,771	945	98	0	0	0	0	0	0	0	0	327	0	0	3,141
1993	1,771	945	100	0	0	0	0	0	0	0	0	332	0	0	3,148
1994	1,421	720	97	0	0	0	0	0	0	0	0	338	0	0	2,576
1995	1,321	445	99	0	0	0	0	0	0	0	0	299	0	0	2,164
1996	1,454	565	99	0	0	0	0	0	0	0	0	322	0	0	2,440
1997	1,730	794	99	0	0	0	0	0	0	0	0	336	200	0	3,159
1998	2,196	858	99	0	0	0	0	0	0	0	0	350	200	0	3,703
1999	2,084	1,138	99	175	0	0	0	0	0	0	0	364	200	0	4,060
2000	2,010	1,286	98	175	0	0	3	0	0	17	0	373	200	0	4,162
2001	2,224	1,379	99	175	0	0	3	0	0	81	0	461	200	0	4,621
2002	2,455	1,513	98	350	0	0	3	0	0	102	0	471	200	0	5,192
2003	2,321	1,513	102	350	0	24	3	42	0	102	0	474	200	0	5,131
2004	2,595	1,600	123	350	0	64	3	86	0	141	0	473	200	60	5,694
2005	2,599	1,658	122	400	0	104	3	132	0	200	0	443	200	100	5,962
2006	2,652	1,630	122	400	0	145	3	177	0	200	0	443	200	100	6,072

TABLE 6.10

1991-2006 COGENERATION PROJECTION FOR HL&P (MW)

	HL&P Forecast	PUC Forecast
1991	945	945
1992	945	945
1993	945	945
1994	720	720
1995	395	445
1996	395	565
1997	395	794
1998	270	858
1999	270	1,138
2000	270	1,286
2001	270	1,379
2002	270	1,513
2003	270	1,513
2004	270	1,600
2005	0	1,658
2006	0	1,630

NOTE:

1. 1991 is actual.
2. These projections are for planning purposes only and do not represent a requirement for long term purchases from QF's. They are based on the staff's assessment that economical opportunities exist for utilities to meet some of the expected capacity requirements with a combination of short-term and long-term cogeneration firm contracts.

4. Market conditions will probably result in firm contracts being renewed under new terms and conditions when they expire or replaced with the same amount of competitively priced new cogeneration.

The actual level of cogeneration on TU Electric's system in 1991 was 1,921 MW (including Alcoa). The staff-recommended amount of cogeneration is shown in Table 6.11. This level of cogeneration could be obtained throughout the forecast period via contract renewal or replacement from competing cogeneration suppliers as well as additional cogeneration power in the state. However, staff sees the existing transmission system as the potential limiting factor for cogenerated power in the late 1990s and beyond. Given the staff's recommendation, about 8.8 percent of TU Electric's net system capacity in the year 2001 will come from cogeneration.

TNP. TNP relies on power purchases for the difference between its total requirements and the output of the new generating stations, TNP One Units 1 and 2. Since TNP withdrew its request for certification of TNP One Units 3 and 4, the PUCT staff's analysis indicates that TNP will rely on more cogenerated power than its existing contracts over the forecast period. This is shown in Table 6.12. Staff's recommended resource plan for TNP's service area includes significantly more cogeneration than that proposed by TNP. If the staff's forecast of demand and capacity resources materializes, about 60 percent of TNP's net system capacity, excluding purchases from HL&P, will be from cogeneration in the year 2001.

Purchased Power

As discussed in previous chapters, most utilities in Texas have surplus capacity. This excess capacity represents a low-cost resource that should be used before constructing new generating units, but institutional impediments exist that prevent all of the state's utilities from buying and selling available capacity.

The greatest impediment to increased bulk power transactions in Texas is the legal distinction between those utilities which are members of ERCOT (intrastate) and those which are members of other reliability councils (interstate). The intrastate utilities in the ERCOT system, with the partial exception of WTU and CPL (members of the interstate Central and Southwest holding company) are currently exempt from regulation by FERC

TABLE 6.11

1991-2006 COGENERATION PROJECTION FOR TU ELECTRIC (MW)

	TU Electric Forecast	PUC Forecast
1991	1,841	1,921
1992	1,691	1,771
1993	1,691	1,771
1994	1,341	1,421
1995	1,241	1,321
1996	1,364	1,454
1997	1,164	1,730
1998	1,164	2,196
1999	854	2,084
2000	880	2,010
2001	1,225	2,224
2002	425	2,455
2003	425	2,321
2004	223	2,595
2005	223	2,599
2006	0	2,652

NOTE:

1. 1991 is actual.
2. These projections are for planning purposes only and do not represent a requirement for long term purchases from QF's. They are based on the staff's assessment that economical opportunities exist for utilities to meet some of the expected capacity requirements with a combination of short-term and long-term cogeneration firm contracts.

TABLE 6.12

COGENERATION PROJECTION FOR TNP (MW)

	TNP Forecast	PUC Forecast
1991	335	335
1992	311	327
1993	301	332
1994	307	338
1995	259	299
1996	274	322
1997	288	336
1998	302	350
1999	316	364
2000	325	373
2001	312	461
2002	322	471
2003	325	474
2004	325	473
2005	305	443
2006	322	443

NOTE:

1. 1991 is actual.
2. These projections are for planning purposes only and do not represent a requirement for long term purchases from QF's. They are based on the staff's assessment that economical opportunities exist for utilities to meet some of the expected capacity requirements with a combination of short-term and long-term cogeneration firm contracts.

TABLE 6.13

TRANSMISSION CAPACITY AND PURCHASED POWER WITHIN THE ERCOT SYSTEM

	BULK POWER TRANSMISSION STUDY			1992 PUCT RESOURCE PLAN			RESULTING
YEAR	BASE CASE	AVG PURCHASE W/ OUTAGE	TOTAL TRANS	COGEN	OTHER	TOTAL	UNUSED CAPACITY
1992	3,741	2,167	5,908	3,043	880	3,923	1,985
1993	4,041	2,114	6,155	3,048	955	4,003	2,152
1994	4,241	2,061	6,302	2,479	773	3,252	3,050
1995	4,441	2,008	6,449	2,065	820	2,885	3,564
1996	4,441	2,008	6,449	2,341	880	3,221	3,228
1997	4,441	2,008	6,449	3,060	657	3,717	2,732
1998	4,441	2,008	6,449	3,604	789	4,393	2,056
1999	4,441	2,008	6,449	3,961	882	4,843	1,606
2000	4,441	2,008	6,449	4,061	672	4,733	1,716
2001	4,441	2,008	6,449	4,520	673	5,193	1,256
2002	4,441	2,008	6,449	5,091	654	5,745	704
2003	4,441	2,008	6,449	5,002	592	5,594	855
2004	4,441	2,008	6,449	5,505	674	6,179	270
2005	4,441	2,008	6,449	5,732	781	6,513	(64)
2006	4,441	2,008	6,449	5,802	909	6,711	(262)

as a result of some special provisions of federal law. Under these legal provisions, they may not engage in bulk power transactions with non-ERCOT utilities without losing their intrastate exemption. However, the East HVDC Tie will allow TU Electric and HL&P to engage in bulk power transactions over the tie beginning in 1995 while maintaining their intrastate exemption.

The staff's Bulk Power Transmission (BPT) study addressed the question of the potential for transactions among the utilities within ERCOT and the potential cost savings which might accrue as a result. However, some of the ERCOT utilities have expressed reservations about the transmission system reliability consequences of trying to exploit these potential transactions.

In developing the recommended levels of purchased power in this resource plan, the staff has relied on the results of the BPT study, evaluated in their most conservative interpretations. For example, as shown in Table 6.13, the staff-recommended total purchased power and cogeneration remains below total transactions with outages mentioned in the BPT Study. Staff figures for the period 2000 through 2003 remain lower than the level recommended for year 2000 in the BPT Study.

Similarly, manual adjustments have been made to the inter-utility sales analysis to lower the transmission system capacity limits below the base case assumptions used in the BPT study. First, instead of using the peak capacity transfer, an average hourly transfer has been calculated which is lower than the peak. Combining these results with the same analysis for 1995 and interpolating for intermediate years, staff determines the transmission capacity available for utility transactions within the ERCOT system. (See Table 6.13.) The recommended levels of purchases in the resource plan are all within these limits for the period ending in 2003. Utilities needing to purchase power will likely be able to find several other utilities with excess capacity for sale.. However, for each potential transaction, a specific reliability load flow analysis should be performed to insure that the integrity of the bulk power transmission system is maintained.

TABLE 6.14

PUCT RESOURCE PLAN
GENERATING UNIT ADDITIONS
1992 - 1995

Year	Utility	Additions [Retirements]	Cost Incl. AFUDC (000's)	MW	Fuel
1992	CPL	Oklaunion Rerating		2	Coal
	CPS	J K Spruce 1	$571,930	498	Coal
	GSU	Repower Louisiana Station		20	Gas
	GSU	Other		73	Gas
	HL&P	Upgrade		40	Gas
	SPS	Unspecified		10	Gas
	TNP	TNP CFB		149	Lignite
	WTU	Rerating		4	Gas
	WTU	Oklaunion Rerating		11	Coal
		Net Capacity Additions		807	
1993	HL&P	Upgrade		15	Gas
	HL&P	Upgrade		40	Coal
	TUEC	Comanche Peak 2	$4,169,823	1,150	Uranium
		Net Capacity Additions		1,205	
1994	Weatherford	Unspecified		10	Gas
	BEPC	R.W. Miller 4&6	$63,757	208	Gas
	HL&P	Upgrade		55	Gas
		Net Capacity Additions		273	
1995	HL&P	Upgrade		15	Gas
	HL&P	DuPont		158	Gas
	LPL	Trash 1		10	Refuse
		Net Capacity Additions		183	
1992-1995 Total Net Capacity Additions				2,468	

Staff-Recommended Additions to Capacity

In the resource plan presented in this section, staff has attempted to consider all potential sources that might be available to meet the peak demand and energy requirements facing electric utilities in Texas over the next ten years. Also, the staff has relied upon the findings from several studies prepared by the PUCT staff in which more reliance on purchased power and more efficient use of the existing capacity and transmission system within ERCOT were emphasized.

The staff-recommended additions during the next ten years (1992 to 2001) reflect the demand-side adjustments to the peak demand forecasts, the peak generation requirements, and the available supply-side options. By the end of the ten years, inaccuracies inherent in the long-term peak demand forecast are estimated not to exceed 5 percent of unadjusted peak demand. This implies some 3,300 MW of variance due to forecasting error, the equivalent of five to six conventional power plants. Because of this variation, the following recommendations should be viewed as a general planning guide rather than a detailed blueprint for capacity additions.

In developing a recommended resource plan for six utilities (TU Electric Company, HL&P, CPL, WTU, SWEPCO, and LCRA), the PUCT staff relied upon the resource planning models implemented and maintained at The University of Texas at Austin Center for Energy Studies (CES). These models include LMSTM (the Load Management Strategy Testing Model) and PROSCREEN.

These resource planning models were implemented by CES and the PUCT staff under the demand forecasts, fuel price projections, cogeneration projections, and planning assumptions endorsed by the staff. A set of hypothetical DSM programs were screened and cost-effective demand side resources were included in the staff's resource plan. Scenario and feasibility analyses were conducted on the possible on-line dates of utility-planned capacity additions and the utilization of alternative resources to construct a low-cost and robust suggested resource plan. In some cases, optimization techniques were used to identify a least-cost capacity addition plan. Using these models, future average system rates, revenue requirements, and fuel requirements under alternative resource plans were derived. This resource planning analysis is described in greater detail in a companion report. (See Center for Energy Studies, Contribution to the Commission Staff's Forecast '92 Project, January 1993.)

The staff-recommended resource plan is based on staff's recent electricity sales and peak demand forecast. If demand materializes that is significantly higher than the demand forecast by staff, there will be a deficit in the net system capacity for Texas and ERCOT beyond 1996.

New units and the costs of alternatives will be reviewed in future certification proceedings, but, at this point in time, staff recommends the completion of 2,458 MW of conventional power plants already under construction. A portion of this capacity (807 MW) has already been added to the state's power plant capacity in 1992. (See Table 6.14.) Additional capacity requirements could be met by construction of conventional power plants through the year 2001.

Utilities have already postponed the retirement dates of many generating units. Over the next ten years, electric utilities in Texas will retire only about 175 MW of capacity. In contrast, a significant amount of capacity, 1,700 MW, is scheduled for retirement between 2002 and 2006. To meet the total net system capacity of 71,900 MW by the year 2001, 66,113 MW could be supplied by conventional power plants, 4,621 MW by cogeneration, 258 MW by interregional net purchased power, and 908 MW by current generating unit life extension projects through repowering. Table 6.15 lists the staff-recommended total capacity additions during the 1992 to 2006 period, with generating units grouped by fuel type. Approximately 4,139 MW of primarily coal-fueled and lignite-fueled base load and 489 MW of gas-fueled capacity scheduled in current utility filings have been deferred beyond the year 2006 in this plan. Table 6.16 lists the staff-recommended specific plant additions for 1992 to 2006.

TU Electric. The staff demand projection is lower than the projection by TU Electric throughout the forecast period. Therefore, staff sees opportunities to defer some base load units and rely on more purchased power (utility and non-utility) than is reported by the utility in its December 1991 filing. Specifically, staff is proposing deferral of Twin Oak Units 1 and 2 by six and seven years, respectively (to 2003 and 2005). The newest resource plan, which was finalized by TU Electric in late 1992, shows a two-year deferral for each unit to 1999 and 2000, respectively. While TU Electric has a Certificate of Convenience and Necessity (CCN) for both units of Twin Oaks, a favorable natural gas market and negative environmental impacts of lignite-fueled units may defer construction of at least the second unit indefinitely.

TABLE 6.15

STAFF RESOURCE PLAN
TEXAS DETAILED CAPACITY EXPANSION

	NG/OIL	COAL	LIGNITE	NUCLEAR	HYDRO	ALT. SOURCES	TOTAL
1991	38,193	8,956	8.801	4,426	642	30	61,048
1992	38,228	9,441	8.949	4,415	642	29	61,704
1993	38,303	9,501	8.951	5,570	642	29	62,996
1994	38,539	9,517	8.958	5,562	642	29	63,247
1994	38,770	9.533	8.962	5,567	642	40	63,514
1996	38,795	9,546	8.963	5,566	642	40	63,552
1997	39,187	9.560	8.969	5,578	642	40	63,976
1998	39,366	9,564	8.970	5,577	642	40	64,159
1999	40,249	9.568	8.970	5,576	642	40	65,045
2000	41,394	9.625	8.973	5,575	642	40	66,248
2001	42,164	9.628	8.973	5,575	642	40	67,021
2002	42,879	9.631	8.973	5,573	642	47	67,746
2003	43,586	9.633	9.724	5,572	642	48	69,205
2004	44,268	9.635	9.723	5,571	642	48	69,886
2005	44,559	10.136	10.473	5,569	642	48	71,427
2006	45,237	10.138	10.473	5,568	642	48	72,106

TABLE 6.16

SCHEDULED ADDITIONS AND RETIREMENTS, 1992-2006
PUCT RESOURCE PLAN

Commercial Operation Date Staff	Utility	Utility	Additions [Retirements]	Cost Incl. AFUDC (000's)	MW	Fuel
1992	1992	CPL	Oklaunion Rerating		2	Coal
1992	1992	CPS	J K Spruce 1	$571,930	498	Coal
1992	1992	GSU	Repower Louisiana Station		20	Gas
1992	1992	GSU	Other		73	Gas
1992	1992	HL&P	Upgrade		40	Gas
1992	1992	SPS	Unspecified		10	Gas
1992	1992	TNP	TNP CFB		149	Lignite
1992	1992	WTU	Rerating		4	Gas
1992	1992	WTU	Oklaunion Rerating		11	Coal
			Net Capacity Additions		807	
1993	1993	HL&P	Upgrade		15	Gas
1993	1993	HL&P	Upgrade		40	Coal
1993	1993	TUEC	Comanche Peak 2	$4,169,823	1,150	Uranium
			Net Capacity Additions		1,205	
1994	1994	Weatherford	Unspecified		10	Gas
1994	1994	BEPC	R.W. Miller 4&5	$63,756	208	Gas
1994	1994	HL&P	Upgrade		55	Gas
			Net Capacity Additions		273	
1995	1995	HL&P	Upgrade		15	Gas
1995	1995	HL&P	DuPont		158	Gas
1995	1995	LPL	Trash 1		10	Refuse
			Net Capacity Additions		183	
1996	1996	HL&P	Upgrade		15	Gas
			Net Capacity Additions		15	
1997	1997	BEPC	Unnamed	$174,363	104	Gas
1997	1997	GSU	Relicense River Bend		33	Uranium
1997	2001	TUEC	Undesignated PSI		290	Gas
			Net Capacity Additions		427	
1998	1996	HL&P	Webster 1&2		220	Gas
1998	1998	WTU	[Lake Pauline 1]		(19)	Gas
1998	1998	WTU	[Fort Stockton 2]		(5)	Gas
1998	1998	WTU	[Abilene 4]		(18)	Gas
			Net Capacity Additions		178	
1999	1999	SPS	Moore County Plant		48	Gas
1999	1999	TMPA	Unnamed		200	Gas
1999	1999	TUEC	Undesignated CC		645	Gas
			Net Capacity Additions		893	
2000	2000	BEPC	Unnamed		104	Gas
2000	2000	HL&P	Unknown		160	Gas
2000	2000	LPL	Combined 1		50	Coal
2000	2000	SPS	Denver City	$6,324	50	Gas
2000	2000	TUEC	Undesignated CC		645	Gas
2000	2000	WTU	[Rio Pecos 4 & 5]		(41)	Gas
2000	2000	WTU	Repower Rio Pecos 5		122	Gas

TABLE 6.16
(Continued)
SCHEDULED ADDITIONS AND RETIREMENTS, 1992-2006
PUCT RESOURCE PLAN

Commercial Operation Date Staff	Utility	Utility	Additions [Retirements]	Cost Incl. AFUDC (000's)	MW	Fuel
2000	2000	WTU	WTU CC 1	$69,111	114	Gas
			Net Capacity Additions		1,204	
2001	2001	BEPC	Unnamed		104	Gas
2001	2001	CPL	[Laredo 2]		(34)	Gas
2001	2001	CPL	[Laredo 1]		(36)	Gas
2001	1999	CPS	GT 99	$37,038	140	Gas
2001	2000	EPE	Turbine 1	$41,250	80	Gas
2001	1998	HL&P	Greens Bayou 3,4		220	Gas
2001	2001	SPS	Refurbish Riverview	$3,065	25	Gas
2001	2001	SWEPCO	Repower Wilkes 2	$43,732	87	Gas
2001	2001	SWEPCO	[Lieberman 1&2]		(56)	Gas
2001	2002	TUEC	Undesignated CT		272	Gas
			Net Capacity Additions		802	
2002	2002	CPL	[JL Bates]		(74)	Gas
2002	2000	CPS	GT 00	$77,052	140	Gas
2002	2002	GSU	Unknown		17	GP*
2002	1998	HL&P	Unknown		219	Gas
2002	2002	SWEPCO	Wilkes 3	$43,732	87	Gas
2002	2002	SWEPCO	[Knox Lee 2&3]		(74)	Gas
2002	2002	TUEC	[River Crest]		(110)	Gas
2002	2002	TUEC	Upgrade		31	Gas
2002	2002	TUEC	[Eagle Mountain]		(115)	Gas
2002	2002	TUEC	[Parkdale]		(87)	Gas
2002	2002	TUEC	Undesignated CC		620	Gas
2002	2002	WTU	WTU CC 2	$69,111	114	Gas
2002	2002	WTU	[Lake Pauline 2]		(27)	Gas
			Net Capacity Additions		741	
2003	2002	BEPC	Unnamed		104	Gas
2003	2001	CPL	Repower Laredo 2	$53,136	123	Gas
2003	2001	CPS	GT 01	$80,195	140	Gas
2003	2000	HL&P	Unknown		206	Gas
2003	2001	HL&P	Unknown		206	Gas
2003		SWEPCO	Unnamed		130	Gas
2003	2003	SWEPCO	[Lone Star 1]		(50)	Gas
2003	2003	TUEC	[Mountain Creek 6]		(115)	Gas
2003	1997	TUEC	Twin Oak 1	$1,589,169	750	Lignite
2003	2003	TUEC	[Parkdale 2,3]		(240)	Gas
2003	2003	TUEC	Undesignated CT		272	Gas
2003	2003	WTU	[Paint Creek 1]		(33)	Gas
			Net Capacity Additions		1,493	
2004	2004	CPL	[Lon C. Hill 3]		(158)	Gas
2004	2004	CPL	[Victoria]		(45)	Gas
2004	2004	CPL	[LC Hill]		(71)	Gas
2004	2002	CPL	Repower JL Bates	$94,393	237	Gas
2004		CPS	GT 04		140	Gas
2004	1999	GSU	Sabine 4	$500	26	Gas

TABLE 6.16
(Continued)
SCHEDULED ADDITIONS AND RETIREMENTS, 1992-2006
PUCT RESOURCE PLAN

Commercial Operation Date Staff	Commercial Operation Date Utility	Utility	Additions [Retirements]	Cost Incl. AFUDC (000's)	MW	Fuel
2004	2002	HL&P	Unknown		206	Gas
2004		SWEPCO	Unnamed		130	Gas
2004	2004	TUEC	Undesignated CT		272	Gas
2004	2004	TUEC	Upgrade		16	Gas
			Net Capacity Additions		753	
2005	2005	CPL	[La Palma 7]		(47)	Gas
2005	2004	CPL	Repower LC Hill 1		244	Gas
2005	2005	CPL	JL Bates		(111)	Gas
2005	2002	CPS	JK Spruce 2	$763,639	500	Coal
2005	2004	GSU	Neches 4.5	$1,067	100	Gas
2005	2002	HL&P	Unknown		206	Gas
2005		SWEPCO	Unnamed		80	Gas
2005	1998	TUEC	Twin Oak 2	$926,471	750	Lignite
2005	2005	WTU	[Paint Creek 2&3]		(87)	Gas
			Net Capacity Additions		1,635	
2006	2006	CPS	Unspecified		(100)	Gas
2006	2004	GSU	Neches 6		60	Gas
2006	2004	HL&P	Unknown		160	Gas
2006	2003	HL&P	Unknown		206	Gas
2006	2006	SWEPCO	[Knox Lee 4]		(83)	Gas
2006	2006	SWEPCO	SWEPCO CT	$61,760	146	Gas
2006	2006	SWEPCO	SWEPCO CC	$105,861	218	Gas
2006	2006	SWEPCO	[Lieberman 3&4]		(220)	Gas
2006	2006	TUEC	Undesignated CT		242	Gas
2006	2006	WTU	WTU CC 3	$69,111	114	Gas
			Net Capacity Additions		743	

1992-1995	2,468 MW
1992-2001	5,987 MW
2002-2006	5,365 MW
1992-2006	11,352 MW

* Natural gas pressure-drop at Sabine site to provide energy supply.

In contrast, four unspecified gas units for 290 MW (2 x 145) and 272 MW (2 x 136) are recommended by the staff for earlier commercial operation by four years and one year, respectively. Finally, two unspecified base load units, a 660-MW lignite unit and a 650-MW coal unit, planned for 2003 and 2005, respectively, are recommended for deferral to beyond the forecast horizon. By following the staff's resource plan, TU Electric can maintain an 18 percent reserve margin, well above the 15 percent minimum reserve margin recommended by ERCOT.

HL&P. Staff's demand projection for 1994 and beyond is higher than the forecast filed by HL&P. However, due to economically available cogeneration within HL&P's service area, staff sees opportunities to recommend deferral of some of the proposed units. PUCT staff recommends that HL&P defer construction of Malakoff Unit 1 to beyond year 2006. This lignite unit, with expected capacity of 645 MW, was scheduled for serving system summer peak in 2005. While HL&P has a CCN for both units of Malakoff, a favorable natural gas market and negative environmental impacts of lignite-fueled units may defer construction of Malakoff units indefinitely.

The PUCT staff recommends further deferral of refurbishments on the Webster Units (1 and 2) and the Greens Bayou Units (3 and 4) by two years, to 1998, and three years to 2001, respectively. Further deferrals on several unnamed HL&P gas-fueled units are recommended by staff.

As discussed previously in the section on cogeneration, HL&P could extend existing contracts or negotiate new contracts with cogeneration power suppliers to meet some of its growth in demand. According to the staff's resource plan, HL&P will have adequate system capacity to maintain at least an 18 percent reserve margin throughout the forecast period.

GSU. Staff's and GSU's demand forecasts are very similar. GSU has several projects to increase the capacity of its existing units. Staff recommends deferral of some of those projects to later years.

CPL. Staff projects slightly lower growth in demand for the CPL service area up to 2000. The difference between the forecasts prepared by the staff and CPL becomes significant toward the end of the forecast period. This suggests the possibility of deferring the repowering of natural gas-fueled Laredo Unit 2, J. L. Bates Unit 1, and L. C. Hill Unit 1 to 2003, 2004, and 2005, respectively. Furthermore, staff recommends deferral of

SWEPCO Lignite Unit 1 and Coleto Unit 2 coal-fueled unit from the planned 2003 and 2005 service dates, respectively, to beyond the year 2006.

CPS. CPS recently completed construction of the 498-MW J. K. Spruce 1 coal unit in spite of significant excess capacity. Staff recommends J. K. Spruce 2 be deferred by three years to 2005. Further deferral of smaller gas-fueled units is also proposed in the staff resource plan.

SPS. Staff's and SPS's demand forecasts are very similar. SPS is proposing minor changes to its capacity in the late 1990s and early 2000s and staff agrees with those capacity additions.

SWEPCO. While staff has a higher peak demand projection than the utility, both forecasts are close for most of the 1990s. Staff recommends deferral of the repowering of Wilkes Units 2 and 3 by two years each from 2001 and 2002, respectively. In addition, staff recommends deferral of SWEPCO Lignite Unit 1 and Coleto Unit 2 coal-fueled unit from the planned 2003 and 2005 service dates, respectively, to beyond the year 2006. Finally, staff's resource plan includes an 80-MW gas-fueled unit for commercial operation in 2005.

LCRA. Staff demand projections are higher than LCRA beyond 1998. However, staff believes that the other resources available to LCRA may result in the deferral of an 88-MW gas-fueled unit planned for completion in 1998. Staff recommends that this unit be deferred to beyond the forecast period. Staff does not see a need for LCRA's service area before 2003 at which time additional power may be obtained from cogeneration or other alternative resources.

COA. Staff's demand projections are lower than the city's beyond the year 1999. Also, through successful demand-side programs, COA has been able to control its fast growing demand for electricity. As a result, adequate capacity is available within COA's service area and staff recommends deferral of a proposed 400-MW coal unit and a 100-MW gas unit to beyond the forecast period.

WTU. Demand projections by staff and the utility are close. Staff recommends deferral of SWEPCO Lignite Unit 1 and Coleto Unit 2 coal-fueled unit from the planned 2003 and 2005 service dates, respectively, to beyond the year 2006.

EPE. Demand projections by staff and the utility are very close. Staff recommends that a 80-MW gas unit proposed for 2000 be deferred by one year, and another 80-MW gas unit be deferred to beyond 2006. EPE also has the option of considering lower reserve margins for planning purposes.

TNP. Demand projections by staff are higher than the forecast filed by TNP. However, due to economically available cogenerated power within TNP's service area and the environmental concerns about lignite units, staff sees opportunities for the company to defer a 149-MW lignite unit to beyond 2006.

BEPC. Demand projections by staff are higher than the cooperative's forecast. However, staff sees opportunities for BEPC to utilize some cogenerated power in the second half of 1990s. Staff recommends that BEPC's 283-MW unnamed gas-fueled unit for 1997 be replaced by a 104-MW unit. In addition, staff recommends a one year delay on a 104-MW gas unit proposed by BEPC for 2003.

A list of coal-fueled, lignite-fueled, and gas-fueled capacity scheduled in current utility filings that have been recommended by staff for deferral to beyond the year 2006 is shown in Table 6.17. In addition, a summary of the annual power plant additions for the 13 major electric utilities is presented in Table 6.18. Resource plans for individual utilities based on the staff's peak demand projections are provided in Appendix A.

Tables 6.19, 6.21, and 6.23 summarize the staff's demand and capacity forecasts for Texas during the 1991-2006 period. In addition, results for ERCOT are summarized in Tables 6.20, 6.22, and 6.24. As verified in Tables 6.23 and 6.24, the recommended resource plans result in reserve margins significantly in excess of the target for Texas, as well as for ERCOT in the early to mid-1990s. However, the declining reserve margins approach (but still exceed) the specified targets early in the next century.

Flexibility in Staff-Recommended Resource Plan

The base-case peak demand projection by the PUCT staff prior to demand adjustments is less than 1 percent below the utilities' peak demand projection for 2001. If demand adjustments are taken into consideration, staff's peak demand projections are slightly higher than the projections by the utilities for that year. Staff believes that its resource plan, which relies on smaller utility-owned additions to capacity, is flexible enough to handle either its recommended base case demand forecasts or the utilities' slightly lower demand projections.

TABLE 6.17

GENERATING UNITS PROPOSED BY STAFF FOR DEFERRAL
BEYOND YEAR 2006

Commercial Operation Date Staff	Year	Utility	Additions [Retirements]	Cost Incl. AFUDC (000's)	MW	Fuel Type
OUT	1998	LCRA	Unknown		88	Gas
OUT	1999	GSU	Willow Glen 4.5	$800	36	Gas
OUT	1999	GSU	Nelson 3,4	$5,600	58	Gas
OUT	2000	GSU	Neches 8	$2,534	105	Gas
OUT	2001	GSU	Willow Glen 3	$4,000	22	Gas
OUT	2001	TNP	TNP CFB	$456,543	149	Lignite
OUT	2003	COA	Gas Turbine	$37,000	100	Gas
OUT	2003	CPL	SWEPCO Lignite		193	Lignite
OUT	2003	SWEPCO	SWEPCO Lignite	$785,880	227	Lignite
OUT	2003	TUEC	Undesignated GS1		660	Lignite
OUT	2003	WTU	SWEPCO Lignite		82	Lignite
OUT	2004	COA	FB Coal	$568,000	400	Coal
OUT	2005	CPL	Coleto	$584,046	373	Coal
OUT	2005	CPS	Unnamed	$1,099,116	500	Lignite
OUT	2005	HL&P	Malakoff (1)		645	Lignite
OUT	2005	SWEPCO	Coleto		112	Coal
OUT	2005	TUEC	Undesignated GS1		650	Coal
OUT	2005	WTU	Coleto		140	Coal
OUT	2006	EPE	Turbine 2	$45,600	80	Gas
			Net Recommended Capacity for Deferral		4,620 MW	

Note: Capacity shown for Coleto Creek and SWEPCO lignite indicate that utility's share of the unit.

TABLE 6.18

STAFF RECOMMENDED NET POWER PLANT ADDITIONS
BY UTILITY (MW)

Year	TU	HL&P	GSU	CPL	CPS	SPS	SWEPCO	LCRA	COA	WTU	EPE	TNP	BEPC	OTHER	TEXAS
1992		40	93	2	498	10				15		149			807
1993	1,150	55													1,205
1994		55											208	10	273
1995		173												10	183
1996		15													15
1997	290		33										104		427
1998		220								-42					178
1999	645					48								200	893
2000	645	160				50				195			104	50	1,204
2001	272	220		-70	140	25	31				80		104		802
2002	339	219	17	-74	140		13			87					741
2003	667	412		123	140		80			-33			104		1,493
2004	288	206	26	-37	140		130								753
2005	750	206	100	86	500		80			-87					1,635
2006	242	366	60		-100		61			114					743
Total	5,288	2,347	329	30	1,458	133	395	0	0	249	80	149	624	270	11,352

TABLE 6.19
PEAK DEMAND AND DEMAND ADJUSTMENTS - TEXAS
(MW)

YEAR	PEAK DEMAND Before Adj.	ADJUSTMENTS TO PEAK DEMAND EXOGENOUS FACTORS	ACTIVE DSM	PASSIVE DSM	PEAK DEMAND After Adj.
1991	47,538	0	0	0	47,538
1992	50,881	7	(1,862)	(111)	48,915
1993	52,423	(19)	(1,995)	(228)	50,181
1994	53,939	(103)	(1,854)	(386)	51,595
1995	55,636	(169)	(2,022)	(573)	52,871
1996	57,354	(180)	(2,165)	(769)	54,241
1997	58,956	(229)	(2,252)	(989)	55,485
1998	60,461	(282)	(2,346)	(1,178)	56,656
1999	62,001	(285)	(2,438)	(1,382)	57,897
2000	63,537	(287)	(2,492)	(1,594)	59,164
2001	65,115	(289)	(2,535)	(1,806)	60,486
2002	66,653	(310)	(2,570)	(1,991)	61,782
2003	68,105	(309)	(2,591)	(2,167)	63,039
2004	69,570	(309)	(2,613)	(2,356)	64,292
2005	70,981	(308)	(2,634)	(2,543)	65,496
2006	72,512	(308)	(2,655)	(2,757)	66,792

NOTE: Texas figures are adjusted downward by 1 percent to reflect load diversity among Texas utilities.

TABLE 6.20
PEAK DEMAND AND DEMAND ADJUSTMENTS - ERCOT
(MW)

YEAR	PEAK DEMAND Before Adj.	ADJUSTMENTS TO PEAK DEMAND EXOGENOUS FACTORS	ACTIVE DSM	PASSIVE DSM	PEAK DEMAND After Adj.
1991	40,039	0	0	0	40.039
1992	43,122	42	(1,699)	(110)	41,354
1993	44,265	(31)	(1.794)	(225)	42.215
1994	45,587	(102)	(1,652)	(382)	43,451
1995	47,038	(156)	(1.821)	(566)	44.495
1996	48,583	(214)	(1,963)	(760)	45,646
1997	50,013	(262)	(2.051)	(978)	46,721
1998	51,364	(311)	(2,145)	(1,165)	47,744
1999	52,755	(316)	(2.237)	(1,367)	48.836
2000	54,132	(320)	(2,291)	(1,577)	49,944
2001	55,571	(325)	(2,333)	(1,787)	51.126
2002	56,962	(346)	(2,369)	(1,970)	52,278
2003	58,271	(345)	(2,390)	(2,143)	53.394
2004	59,595	(345)	(2,412)	(2,330)	54,508
2005	60,863	(344)	(2,432)	(2,515)	55,572
2006	62,254	(344)	(2,453)	(2,727)	56,731

NOTE: Texas figures are adjusted downward by 1 percent to reflect load diversity among Texas utilities.

TABLE 6.21
INSTALLED CAPACITY - TEXAS
(MW)

YEAR	NATURAL GAS/OIL	COAL	LIGNITE	NUCLEAR	ALTERNATIVE ENERGY SOURCES (HYDRO)	ALLOCATION FACTOR	TOTAL INSTALLED GENERATING CAPACITY
1991	38,193	8,956	8,801	4,426	672	89.94%	61,048
1992	38,228	9,441	8,949	4,415	671	89.83%	61,704
1993	38,303	9,501	8,951	5,570	671	90.13%	62,996
1994	38,539	9,517	8,958	5,562	672	90.14%	63,247
1995	38,770	9,533	8,962	5,567	682	90.29%	63,514
1996	38,795	9,546	8,963	5,566	682	90.32%	63,552
1997	39,187	9,560	8,969	5,578	682	90.37%	63,976
1998	39,366	9,564	8,970	5,577	682	90.41%	64,159
1999	40,249	9,568	8,970	5,576	682	90.52%	65,045
2000	41,394	9,625	8,973	5,575	682	90.67%	66,248
2001	42,164	9,628	8,973	5,575	682	90.73%	67,021
2002	42,879	9,631	8,973	5,573	690	90.80%	67,746
2003	43,586	9,633	9,724	5,572	690	90.94%	69,205
2004	44,268	9,635	9,723	5,571	690	90.93%	69,886
2005	44,559	10,136	10,473	5,569	690	91.00%	71,427
2006	45,237	10,138	10,473	5,568	690	91.01%	72,106

TABLE 6.22
INSTALLED CAPACITY - ERCOT
(MW)

YEAR	NATURAL GAS/OIL	COAL	LIGNITE	NUCLEAR	ALTERNATIVE ENERGY SOURCES (HYDRO)	ALLOCATION FACTOR	TOTAL INSTALLED GENERATING CAPACITY
1991	32,624	5,819	8,225	3,650	454	100.00%	50,772
1992	32,668	6,330	8,374	3,650	454	100.00%	51,476
1993	32,683	6,370	8,374	4,800	454	100.00%	52,681
1994	32,956	6,370	8,374	4,800	454	100.00%	52,954
1995	33,129	6,370	8,374	4,800	454	100.00%	53,127
1996	33,144	6,370	8,374	4,800	454	100.00%	53,142
1997	33,538	6,370	8,374	4,800	454	100.00%	53,536
1998	33,716	6,370	8,374	4,800	454	100.00%	53,714
1999	34,561	6,370	8,374	4,800	454	100.00%	54,559
2000	35,665	6,370	8,374	4,800	454	100.00%	55,663
2001	36,331	6,370	8,374	4,800	454	100.00%	56,329
2002	37,042	6,370	8,374	4,800	454	100.00%	57,040
2003	37,705	6,370	9,124	4,800	454	100.00%	58,453
2004	38,302	6,370	9,124	4,800	454	100.00%	59,050
2005	38,507	6,870	9,874	4,800	454	100.00%	60,505
2006	39,129	6,870	9,874	4,800	454	100.00%	61,127

TABLE 6.23
NET SYSTEM CAPACITY AND RESERVE MARGIN - TEXAS
(MW)

YEAR	FIRM PURCHASES FROM UTILITIES	FIRM PURCHASES FROM NON-UTILITIES	FIRM OFF-SYSTEM SALES	NET SYSTEM CAPACITY	RESERVE MARGIN (%)	TARGET MARGIN (%)	EXCESS CAPACITY
1991	1,039	3,206	1,072	64,221	35.09%	17.37%	8,427
1992	1,194	3,141	1,309	64,730	32.33%	16.83%	7,581
1993	1,352	3,148	1,436	66,060	31.64%	17.50%	7,100
1994	1,182	2,576	1,268	65,737	27.41%	16.77%	5,492
1995	1,310	2,164	1,318	65,670	24.21%	16.75%	3,941
1996	1,431	2,440	1,399	66,026	21.73%	16.72%	2,713
1997	1,097	3,159	947	67,284	21.26%	16.70%	2,535
1998	1,285	3,703	1,121	68,025	20.07%	16.67%	1,926
1999	1,410	4,060	1,230	69,284	19.67%	16.64%	1,756
2000	1,200	4,162	983	70,627	19.37%	16.62%	1,630
2001	1,185	4,621	927	71,900	18.87%	16.58%	1,385
2002	1,214	5,192	856	73,296	18.64%	16.59%	1,266
2003	1,164	5,131	705	74,795	18.65%	16.59%	1,296
2004	1,239	5,694	793	76,026	18.25%	16.60%	1,061
2005	1,357	5,962	893	77,853	18.87%	16.61%	1,477
2006	1,537	6,072	1,026	78,688	17.81%	16.61%	800

TABLE 6.24
NET SYSTEM CAPACITY AND RESERVE MARGIN - ERCOT
(MW)

YEAR	FIRM PURCHASES FROM UTILITIES	FIRM PURCHASES FROM NON-UTILITIES	FIRM OFF-SYSTEM SALES	NET SYSTEM CAPACITY	RESERVE MARGIN (%)	TARGET MARGIN (%)	EXCESS CAPACITY
1991	774	3,201	774	53,973	34.80%	17.66%	6,861
1992	880	3,043	880	54,519	31.83%	17.04%	6,119
1993	955	3,048	955	55,729	32.01%	17.84%	5,984
1994	773	2,479	773	55,433	27.58%	16.99%	4,600
1995	820	2,065	820	55,192	24.04%	16.98%	3,144
1996	880	2,341	880	55,483	21.55%	16.94%	2,104
1997	657	3,060	657	56,596	21.14%	16.91%	1,976
1998	789	3,604	789	57,318	20.05%	16.87%	1,518
1999	882	3,961	882	58,520	19.83%	16.83%	1,464
2000	672	4,061	672	59,724	19.58%	16.81%	1,383
2001	673	4,520	673	60,849	19.02%	16.76%	1,151
2002	654	5,091	654	62,131	18.85%	16.77%	1,086
2003	592	5,002	592	63,455	18.84%	16.78%	1,104
2004	674	5,505	674	64,555	18.43%	16.78%	898
2005	781	5,732	781	66,237	19.19%	16.79%	1,332
2006	909	5,802	909	66,929	17.98%	16.79%	671

Due to uncertainties associated with peak demand projections, staff has analyzed a scenario in which peak demand projections after demand adjustments are 5 percent higher than those used in the staff's base case resource plan. This results in 2.9 percent rather than 2.4 percent annual growth in peak demand after demand adjustments for Texas in 2001. Staff analysis indicates that Texas as well as ERCOT may face capacity deficits in 1997 under the high-demand scenario. Under this scenario, there would be a need for over 1,600 MW of additional resources in 2001. The capacity deficit would grow to over 2,500 MW by year 2006.

Staff believes that there are several resources that could be utilized to overcome the resulting capacity deficit under the high-demand scenario. Construction of new units is obviously one solution. Staff also believes that additional effective demand-side management programs could help reduce the growth in peak demand. Given the availability of transmission lines and improvements made to the transmission system, cogeneration may be utilized more extensively to help ease any capacity deficiency. Finally, generation unit life extension projects may also be used to provide additional power to overcome capacity deficits.

<u>CHAPTER SEVEN</u>

RECOMMENDATION AND CONCLUSIONS

Recommendation

The PUCT staff recommends the adoption of this report as the 1992 Statewide Electrical Energy Plan described in the Texas Public Utility Regulatory Act (PURA).

Conclusions

The Electric Division staff concludes that the major electric utilities in Texas are now, and will remain, low-cost and reliable suppliers of electrical services. Based on analyses conducted throughout 1992 as presented in Volume I, staff concludes the following:

1. Statewide peak demand is expected to grow at an average annual rate of 2.4 percent from 1992 to 2001.
2. Electricity sales are expected to grow at an average annual rate of 2.6 percent during the same period.
3. Bulk power transactions and purchases form qualifying facilities will provide a greater contribution to resources than reported by the utilities.
4. Approximately 4,600 MW of firm capacity will be purchased from qualifying facilities in 2001. This is about 2,700 MW greater than the utilities' projections for that year.
5. Active DSM (mostly industrial interruptible loads) will contribute an additional 1,119 MW to the resource mix in 2001. Passive DSM will contribute an additional 1,806 MW by that year.
6. Some power plants may be economically deferred beyond the utilities' projected on-line dates without compromising reliability. About 3,000 MW of power plant capacity proposed by utilities may be deferred beyond the year 2001.

7. Average electricity prices in Texas are expected to remain lower than national averages. Electricity prices in Texas are expected to increase at a pace below the rate of general inflation. As a result, the real price of electricity will decline over the forecast period.

Although the outlook for the state's electric power industry is generally favorable, a number of critical issues deserve prompt attention from the utilities and the Commission:

1. Alleviation of transmission bottlenecks.
2. Moderation of near-term rate increases to prevent widespread self-generation or bypass.
3. Closer scrutiny of promotional activities.
4. Closer attention to end-use energy efficiency programs.
5. Further research of solar and wind technologies.
6. Consideration of dispersed resources to defer investments in transmission and distribution system upgrades.

Resource Planning Issues

In addition to the critical issues highlighted in the previous section, a discussion of important planning issues is provided in the next section. Collectively, these studies and comments form a comprehensive body of information that provides the foundation for policy-making and refinement of the regulatory process.

IRP and the Changing Regulatory Compact

The simple notion that demand-side and supply-side resources should be evaluated in an even-handed fashion has raised some fundamental questions about the process in which utilities conduct their planning. The conventional wisdom has been to forecast load and choose supply options which best match an exogenously-given demand. Today, utility planners believe that an integrated methodology must view the demand or customer side of the meter as a viable resource.

The emergence of new technologies has lead to an increase in competition in both the demand and supply side of the meter. Participation from new players requires a revision in the regulatory compact. Problems such as externalities, access to the transmission network, retail wheeling, the financial integrity of a utility, and bidding must be analyzed.

Bottlenecks in the ERCOT System

Often policies with the intent to increase the ratepayers welfare fail to incorporate the engineering and technical reality of operating an electrical system. Transmission and reliability considerations ultimately determine the extent to which resources in the state can be used efficiently Guidelines established by ERCOT tend to emphasize reliability instead of incentives for power pooling and cogeneration. A review of the certification process for transmission lines is a prerequisite to the successful implementation of policies to achieve greater competition and economic efficiency in the Texas electrical network.

The Role of Externality Analysis in Resource Planning

There is a growing emphasis on formalizing the Commission's consideration of issues external to the utility system. Nowhere is this more evident than in the treatment of the residual emissions of power plants.

A number of states consider environmental externalities in resource planning. The implications for the type and timing of new resources and for the operation of existing power systems are significant. The so-called "monetization" of external environmental impacts will affect the mix of current and future resources. Some observers contend that if the external costs associated with traditional power plants are properly accounted for, alternatives such as demand-side management and cogeneration may become more attractive. Others contend that the federal government and state regulatory agencies have developed environmental standards that adequately protect the environment.

The Commission can monitor the theoretical work in the area of externalities, the empirical work in other states, apply the most promising techniques as needed, and bring parties together to establish standards for the consideration of externalities.

The Potential for Renewable Resources in Texas

Texas is in a prime position to take advantage of opportunities afforded by renewable resources. Additional resources will be needed in just a few years, but the size of the need is small relative to the large units added earlier in the 1980s. The technological advances in wind and solar power have brought the economics within range of serious consideration.

Large areas of West Texas show promise for technical application of solar and wind power. While utilities in that region do not need additional capacity resources, some experimentation is warranted now to develop site-specific experience with the technologies. Policies focused on a long-run view may provide incentives to promote solar power. The staff will continue to monitor advances and cost reductions in renewable resource technologies.

Regulatory impediments to the utilization of alternative energy resources may include the methods of analysis and comparison to traditional capacity resources, the burden of involved regulatory procedures, (e.g., NOI and CCN proceedings) for very small additions to capacity, lack of incentives for purchased power transactions, inadequate data to analyze relative risks, and potential adverse impacts on utilities by the investment community. The staff will continue to study these impediments.

Regulatory Incentives and Disincentives for Energy Efficiency

Traditional regulation inhibits the even-handed consideration of demand-side resources. Rate-of-return regulation results in utility incentives to promote sales and cut costs between rate cases. Lower sales decrease cash flow and profits, thus there is a disincentive for utilities to aggressively implement energy efficiency programs. This disincentive continues until the next rate case when the impact of conservation and promotional activities is "trued up."

There is nothing surprising, or troubling, in this finding, particularly if you are comfortable with the notion that the business of electric utilities is the marketing of a commodity -- kilowatt-hours. However, at the end-use level, the view of electricity as a commodity is unrealistic in an increasingly competitive world. Electric utilities provide energy services, and the most competitive utilities will offer the lowest-cost energy services, not necessarily the lowest-cost per kilowatt-hour. An energy service view is consistent with the encouragement of demand-side efficiency.

Strategic Rate Design

There is an emerging recognition that rate design can be used as a powerful resource planning tool. The structure, levels of charges, and terms and conditions of various rate offerings can have a significant impact on the quantity and timing of electricity consumption. Rate design can thus be considered a resource planning tool because it affects consumption patterns which in turn, influence generation requirements.

Competition and Deregulation in the 1990s

One intent of regulation is to "replicate" the conditions that would exist in a competitive market. However, the assumption of economies of scale that precluded a competitive market in the electric industry has come under great scrutiny. Technological innovations make it possible to conceive of a competitive market for services in which the customer, at the push of a button, will choose their supplier.

Unbundling electric commodities from electric services when feasible will promote competition with innovative, market-oriented pricing. Replacing traditional cost-based pricing with marginal cost pricing can result in greater efficiency of an electric power system. Marginal cost pricing is generally thought to send improved signals to customers concerning the actual resource cost of power. This in turn would allow more economically efficient decisions by customers.

The maturation of new markets may lead to the partial or complete deregulation of power generation, and eventually to the delivery of many customer services. Successful implementation in the generation market requires solving the issues of transmission access and wheeling costs. On the demand-side, several states have bidding mechanisms to promote competition for programs to manage consumption.

The Impact of NAFTA on Power Transfers with Mexico

The growing industrialization of regions across the Mexican-American (e.g., Maquilladores) border and the North American Free trade Agreement (NAFTA) has created new opportunities for Texas utilities. Utilities with excess available capacity may benefit from sales to Mexico. Transmission constraints may limit the transactions, however. Additionally, the timing and nature of these sales presents challenges to the regulatory process. Long term contracts may precipitate the need for new capacity in a host utility, and involve an increase in potential risk from participation in a global market for power.

Collaborative Processes: Finding the Common Ground

Efforts and resources will continue to be wasted if the stakes are viewed as a zero sum game. A sensible alternative is one of partnership because regulators, utilities, and other participants gain from each other. A new perspective puts a premium on collaboration, cooperation, and negotiation. In this setting regulators become arbitrators rather than policemen.

Summary

A significant number of projects and dockets related to resource planning have come before the Commission since the last Statewide Electrical Energy Plan was adopted in early 1991. The Commission has taken the following actions.

1. Adopted a notice of intent rule in May 1991.
2. Published proposed changes to two resource planning-related rules in February 1992.
3. Finalized a task force report on the impacts of electromagnetic fields (EMF) on health in March 1992.
4. Conducted five public forums on IRP in June and July 1992 (IRP, externalities, DSM, transmission access, and purchased power).
5. Adopted new rules regarding the precertification of long-term fuel contracts (September 1992) and more frequent fuel-factor setting and reconciliation (February 1993).
6. Conducted a public forum on renewable resources in February 1993.
7. Requested comments on the unpublished staff IRP rule proposal in February 1993.

It is anticipated that the Commission will continue to address integrated resource planning issues through filed dockets, rule-makings, public workshops and forums, and staff investigations. A responsive regulatory process will be conducive to flexible, more efficient planning.

APPENDIX A

Staff Recommended Capacity Resource Plans by Utility

TABLE A.1

PEAK DEMAND ADJUSTMENTS
TEXAS UTILITIES ELECTRIC COMPANY
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1991	16,831	0	0	0	0	16,831
1992	17,711	61	(424)	(44)	(407)	17,304
1993	18,176	19	(452)	(100)	(533)	17,643
1994	18,669	(23)	(466)	(177)	(666)	18,003
1995	19,359	(55)	(490)	(266)	(811)	18,548
1996	20,058	(88)	(514)	(361)	(963)	19,095
1997	20,707	(118)	(538)	(477)	(1,133)	19,575
1998	21,268	(147)	(562)	(590)	(1,299)	19,969
1999	21,877	(152)	(587)	(716)	(1,455)	20,421
2000	22,517	(156)	(611)	(855)	(1,622)	20,895
2001	23,106	(161)	(635)	(993)	(1,789)	21,317
2002	23,766	(182)	(650)	(1,134)	(1,966)	21,800
2003	24,367	(181)	(665)	(1,269)	(2,115)	22,252
2004	24,983	(181)	(680)	(1,394)	(2,255)	22,728
2005	25,603	(180)	(695)	(1,529)	(2,404)	23,198
2006	26,191	(180)	(710)	(1,684)	(2,574)	23,617

TABLE A.2

INSTALLED CAPACITY
TEXAS UTILITIES ELECTRIC COMPANY
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	12,933	0	5,845	1,150	0	0	19,928
1992	12,933	0	5,845	1,150	0	0	19,928
1993	12,933	0	5,845	2,300	0	0	21,078
1994	12,933	0	5,845	2,300	0	0	21,078
1995	12,933	0	5,845	2,300	0	0	21,078
1996	12,933	0	5,845	2,300	0	0	21,078
1997	13,223	0	5,845	2,300	0	0	21,368
1998	13,223	0	5,845	2,300	0	0	21,368
1999	13,868	0	5,845	2,300	0	0	22,013
2000	14,513	0	5,845	2,300	0	0	22,658
2001	14,785	0	5,845	2,300	0	0	22,930
2002	15,124	0	5,845	2,300	0	0	23,269
2003	15,041	0	6,595	2,300	0	0	23,936
2004	15,329	0	6,595	2,300	0	0	24,224
2005	15,329	0	7,345	2,300	0	0	24,974
2006	15,571	0	7,345	2,300	0	0	25,216

TABLE A.3

NET SYSTEM CAPACITY AND RESERVE MARGINS
TEXAS UTILITIES ELECTRIC COMPANY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	1,921	0	21,849	29.81%	18.00%	1,988
1992	0	1,771	0	21,699	25.40%	18.00%	1,280
1993	0	1,771	0	22,849	29.51%	20.00%	1,677
1994	0	1,421	0	22,499	24.97%	18.00%	1,256
1995	0	1,321	0	22,399	20.76%	18.00%	512
1996	0	1,454	0	22,532	18.00%	18.00%	0
1997	0	1,730	0	23,098	18.00%	18.00%	0
1998	0	2,196	0	23,564	18.00%	18.00%	0
1999	0	2,084	0	24,097	18.00%	18.00%	0
2000	0	2,010	0	24,668	18.06%	18.00%	12
2001	0	2,224	0	25,154	18.00%	18.00%	0
2002	0	2,455	0	25,724	18.00%	18.00%	0
2003	0	2,321	0	26,257	18.00%	18.00%	0
2004	0	2,595	0	26,819	18.00%	18.00%	0
2005	0	2,599	0	27,573	18.86%	18.00%	199
2006	0	2,652	0	27,868	18.00%	18.00%	0

TABLE A.4

PEAK DEMAND AND DEMAND ADJUSTMENTS
HOUSTON LIGHTING & POWER
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	10,908	0	0	0	0	10,908
1992	12,076	(7)	(851)	(25)	(883)	11,193
1993	12,286	(18)	(895)	(62)	(975)	11,311
1994	12,709	(30)	(725)	(106)	(861)	11,848
1995	13,141	(38)	(858)	(171)	(1,067)	12,075
1996	13,510	(47)	(959)	(234)	(1,240)	12,270
1997	13,829	(54)	(1,002)	(302)	(1,358)	12,471
1998	14,160	(62)	(1,047)	(339)	(1,448)	12,712
1999	14,478	(62)	(1,090)	(376)	(1,528)	12,949
2000	14,770	(62)	(1,090)	(407)	(1,559)	13,210
2001	15,070	(62)	(1,090)	(442)	(1,594)	13,475
2002	15,374	(62)	(1,090)	(447)	(1,599)	13,775
2003	15,686	(62)	(1,090)	(453)	(1,605)	14,081
2004	15,982	(62)	(1,090)	(458)	(1,610)	14,372
2005	16,212	(62)	(1,090)	(464)	(1,616)	14,596
2006	16,504	(62)	(1,090)	(469)	(1,621)	14,882

TABLE A.5

INSTALLED CAPACITY
HOUSTON LIGHTING & POWER
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	9,039	2,335	1,440	770	0	0	13,584
1992	9,079	2,335	1,440	770	0	0	13,624
1993	9,094	2,375	1,440	770	0	0	13,679
1994	9,149	2,375	1,440	770	0	0	13,734
1995	9,322	2,375	1,440	770	0	0	13,907
1996	9,337	2,375	1,440	770	0	0	13,922
1997	9,337	2,375	1,440	770	0	0	13,922
1998	9,557	2,375	1,440	770	0	0	14,142
1999	9,557	2,375	1,440	770	0	0	14,142
2000	9,717	2,375	1,440	770	0	0	14,302
2001	9,937	2,375	1,440	770	0	0	14,522
2002	10,156	2,375	1,440	770	0	0	14,741
2003	10,568	2,375	1,440	770	0	0	15,153
2004	10,774	2,375	1,440	770	0	0	15,359
2005	10,980	2,375	1,440	770	0	0	15,565
2006	11,346	2,375	1,440	770	0	0	15,931

TABLE A.6

NET SYSTEM CAPACITY AND RESERVE MARGINS
HOUSTON LIGHTING & POWER
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	945	0	14,529	33.20%	20.00%	1,439
1992	0	945	0	14,569	30.16%	18.00%	1,361
1993	0	945	0	14,624	29.29%	18.00%	1,277
1994	0	720	0	14,454	21.99%	18.00%	473
1995	0	445	0	14,352	18.86%	18.00%	104
1996	0	565	0	14,487	18.07%	18.00%	9
1997	0	794	0	14,716	18.00%	18.00%	0
1998	0	858	0	15,000	18.00%	18.00%	0
1999	0	1,138	0	15,280	18.00%	18.00%	0
2000	0	1,286	0	15,588	18.00%	18.00%	0
2001	0	1,379	0	15,901	18.00%	18.00%	0
2002	0	1,513	0	16,254	18.00%	18.00%	0
2003	0	1,513	0	16,666	18.36%	18.00%	50
2004	0	1,600	0	16,959	18.00%	18.00%	0
2005	0	1,658	0	17,223	18.00%	18.00%	0
2006	0	1,630	0	17,561	18.00%	18.00%	0

TABLE A.7

PEAK DEMAND AND DEMAND ADJUSTMENTS
GULF STATES UTILITIES COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1991	4,922	0	0	0	0	4,922
1992	5,244	(89)	(124)	0	(213)	5,032
1993	5,602	(100)	(124)	0	(224)	5,378
1994	5,685	(112)	(124)	0	(236)	5,449
1995	5,666	(138)	(124)	0	(262)	5,404
1996	5,748	(141)	(124)	0	(265)	5,483
1997	5,796	(143)	(124)	0	(267)	5,529
1998	5,864	(146)	(124)	0	(270)	5,594
1999	5,925	(146)	(124)	0	(270)	5,655
2000	5,985	(146)	(124)	0	(270)	5,715
2001	6,045	(146)	(139)	0	(285)	5,760
2002	6,112	(146)	(139)	0	(285)	5,827
2003	6,177	(146)	(139)	0	(285)	5,892
2004	6,241	(146)	(139)	0	(285)	5,956
2005	6,306	(146)	(139)	0	(285)	6,021
2006	6,372	(146)	(139)	0	(285)	6,087

TABLE A.8

INSTALLED CAPACITY
GULF STATES UTILITIES COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	5,105	612	0	655	0	0	6,372
1992	5,198	612	0	655	0	0	6,465
1993	5,198	612	0	655	0	0	6,465
1994	5,198	612	0	655	0	0	6,465
1995	5,198	612	0	655	0	0	6,465
1996	5,198	612	0	655	0	0	6,465
1997	5,198	612	0	688	0	0	6,498
1998	5,198	612	0	688	0	0	6,498
1999	5,198	612	0	688	0	0	6,498
2000	5,198	612	0	688	0	0	6,498
2001	5,198	612	0	688	0	0	6,498
2002	5,198	612	0	688	0	17	6,515
2003	5,198	612	0	688	0	17	6,515
2004	5,224	612	0	688	0	17	6,541
2005	5,324	612	0	688	0	17	6,641
2006	5,384	612	0	688	0	17	6,701

TABLE A.9

NET SYSTEM CAPACITY AND RESERVE MARGINS
GULF STATES UTILITIES COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	87	11	0	6,470	31.45%	15.30%	795
1992	77	223	0	6,765	34.45%	15.30%	964
1993	77	223	0	6,765	25.79%	15.30%	564
1994	66	223	0	6,754	23.95%	15.30%	471
1995	66	223	0	6,754	24.98%	15.30%	523
1996	46	223	0	6,734	22.82%	15.30%	412
1997	46	223	0	6,767	22.39%	15.30%	392
1998	46	223	0	6,767	20.97%	15.30%	317
1999	46	223	0	6,767	19.66%	15.30%	247
2000	46	223	0	6,767	18.41%	15.30%	178
2001	46	223	0	6,767	17.48%	15.30%	126
2002	46	223	0	6,784	16.42%	15.30%	65
2003	46	232	0	6,793	15.29%	15.30%	0
2004	46	280	0	6,867	15.30%	15.30%	0
2005	46	280	0	6,967	15.71%	15.30%	25
2006	46	280	0	7,027	15.44%	15.30%	9

TABLE A.10

PEAK DEMAND AND DEMAND ADJUSTMENTS
GULF STATES UTILITIES COMPANY
STATE OF TEXAS DATA
(MW)

		Demand Adjustments				
Year	Peak Demand Before Adjustments	Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1991	2,184	0	0	0	0	2,184
1992	2,337	(41)	(91)	0	(132)	2,205
1993	2,543	(44)	(91)	0	(135)	2,408
1994	2,521	(52)	(91)	0	(143)	2,378
1995	2,561	(61)	(91)	0	(152)	2,409
1996	2,597	(63)	(91)	0	(154)	2,443
1997	2,602	(64)	(91)	0	(155)	2,447
1998	2,630	(66)	(91)	0	(157)	2,473
1999	2,656	(66)	(91)	0	(157)	2,499
2000	2,679	(66)	(91)	0	(157)	2,522
2001	2,702	(66)	(91)	0	(157)	2,545
2002	2,725	(66)	(91)	0	(157)	2,568
2003	2,747	(66)	(91)	0	(157)	2,590
2004	2,769	(66)	(91)	0	(157)	2,612
2005	2,791	(66)	(91)	0	(157)	2,634
2006	2,811	(66)	(91)	0	(157)	2,654

TABLE A.11

INSTALLED CAPACITY
GULF STATES UTILITIES COMPANY
STATE OF TEXAS DATA
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	2,265	272	0	291	0	0	2,827
1992	2,278	268	0	287	0	0	2,833
1993	2,327	274	0	293	0	0	2,895
1994	2,268	267	0	286	0	0	2,821
1995	2,317	273	0	292	0	0	2,882
1996	2,316	273	0	292	0	0	2,881
1997	2,301	271	0	304	0	0	2,876
1998	2,298	271	0	304	0	0	2,873
1999	2,297	270	0	304	0	0	2,872
2000	2,294	270	0	304	0	0	2,868
2001	2,297	270	0	304	0	0	2,871
2002	2,291	270	0	303	0	7	2,871
2003	2,285	269	0	302	0	7	2,864
2004	2,291	268	0	302	0	7	2,869
2005	2,329	268	0	301	0	7	2,905
2006	2,347	267	0	300	0	7	2,922

TABLE A.12

NET SYSTEM CAPACITY AND RESERVE MARGINS
GULF STATES UTILITIES COMPANY
STATE OF TEXAS DATA
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	39	5	0	2,871	31.45%	15.30%	353
1992	34	98	0	2,965	34.45%	15.30%	422
1993	34	100	0	3,029	25.79%	15.30%	253
1994	29	97	0	2,948	23.95%	15.30%	206
1995	29	99	0	3,011	24.98%	15.30%	233
1996	20	99	0	3,000	22.82%	15.30%	184
1997	20	99	0	2,995	22.39%	15.30%	174
1998	20	99	0	2,992	20.97%	15.30%	140
1999	20	99	0	2,990	19.66%	15.30%	109
2000	20	98	0	2,986	18.41%	15.30%	78
2001	20	99	0	2,990	17.48%	15.30%	56
2002	20	98	0	2,990	16.42%	15.30%	29
2003	20	102	0	2,986	15.29%	15.30%	0
2004	20	123	0	3,012	15.30%	15.30%	0
2005	20	122	0	3,048	15.71%	15.30%	11
2006	20	122	0	3,064	15.44%	15.30%	4

TABLE A.13

PEAK DEMAND AND DEMAND ADJUSTMENTS
CENTRAL POWER AND LIGHT COMPANY
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments				Peak Demand After Adjustments
		Exogenous Factors	Active DSM	Passive DSM	Total	
1991	3,150	0	0	0	0	3,150
1992	3,482	(3)	(318)	(7)	(328)	3,155
1993	3,574	(8)	(333)	(14)	(355)	3,219
1994	3,708	(13)	(338)	(23)	(374)	3,334
1995	3,768	(17)	(434)	(35)	(486)	3,282
1996	3,883	(21)	(348)	(46)	(415)	3,468
1997	3,977	(24)	(353)	(55)	(432)	3,545
1998	4,070	(27)	(357)	(65)	(449)	3,621
1999	4,164	(27)	(362)	(76)	(465)	3,699
2000	4,247	(27)	(367)	(88)	(482)	3,766
2001	4,326	(27)	(372)	(99)	(498)	3,828
2002	4,415	(27)	(377)	(112)	(516)	3,899
2003	4,479	(27)	(381)	(116)	(524)	3,954
2004	4,540	(27)	(386)	(141)	(554)	3,986
2005	4,607	(27)	(391)	(158)	(576)	4,031
2006	4,670	(27)	(396)	(181)	(604)	4,066

TABLE A.14

INSTALLED CAPACITY
CENTRAL POWER AND LIGHT COMPANY
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	3,105	657	0	630	6	0	4,398
1992	3,105	659	0	630	6	0	4,400
1993	3,105	659	0	630	6	0	4,400
1994	3,105	659	0	630	6	0	4,400
1995	3,105	659	0	630	6	0	4,400
1996	3,105	659	0	630	6	0	4,400
1997	3,105	659	0	630	6	0	4,400
1998	3,105	659	0	630	6	0	4,400
1999	3,105	659	0	630	6	0	4,400
2000	3,105	659	0	630	6	0	4,400
2001	3,035	659	0	630	6	0	4,330
2002	2,961	659	0	630	6	0	4,256
2003	3,084	659	0	630	6	0	4,379
2004	3,047	659	0	630	6	0	4,342
2005	3,133	659	0	630	6	0	4,428
2006	3,133	659	0	630	6	0	4,428

TABLE A.15

**NET SYSTEM CAPACITY AND RESERVE MARGINS
CENTRAL POWER AND LIGHT COMPANY
(MW)**

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	64	4,334	37.59%	18.70%	595
1992	0	0	79	4,321	36.96%	18.20%	592
1993	0	0	60	4,340	34.83%	17.90%	545
1994	0	0	39	4,361	30.80%	17.50%	443
1995	0	0	35	4,365	33.00%	17.10%	522
1996	0	0	14	4,386	26.47%	16.70%	339
1997	0	0	36	4,364	23.12%	16.30%	242
1998	0	0	62	4,338	19.80%	15.90%	141
1999	0	175	121	4,454	20.42%	15.40%	186
2000	14	175	109	4,480	18.97%	15.10%	146
2001	39	175	92	4,452	16.32%	15.00%	50
2002	0	350	113	4,493	15.24%	15.00%	9
2003	0	350	157	4,572	15.62%	15.00%	24
2004	26	350	118	4,600	15.40%	15.00%	16
2005	0	400	146	4,682	16.14%	15.00%	46
2006	30	400	139	4,719	16.07%	15.00%	44

TABLE A.16

PEAK DEMAND AND DEMAND ADJUSTMENTS
CITY PUBLIC SERVICE OF SAN ANTONIO
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	2,799	0	0	0	0	2,799
1992	2,877	(17)	(10)	0	(27)	2,850
1993	2,971	(22)	(10)	0	(32)	2,939
1994	3,082	(26)	(10)	0	(36)	3,046
1995	3,200	(29)	(10)	0	(39)	3,161
1996	3,319	(33)	(10)	0	(43)	3,276
1997	3,441	(35)	(10)	0	(45)	3,396
1998	3,566	(38)	(10)	0	(48)	3,518
1999	3,693	(38)	(10)	0	(48)	3,645
2000	3,825	(38)	(10)	0	(48)	3,777
2001	3,951	(38)	(10)	0	(48)	3,903
2002	4,070	(38)	(10)	0	(48)	4,022
2003	4,195	(26)	(10)	0	(36)	4,159
2004	4,323	(11)	(10)	0	(21)	4,302
2005	4,457	0	(10)	0	(10)	4,447
2006	4,657	0	(10)	0	(10)	4,647

TABLE A.17

INSTALLED CAPACITY
CITY PUBLIC SERVICE OF SAN ANTONIO
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	2,391	810	0	700	0	0	3,901
1992	2,391	1,308	0	700	0	0	4,399
1993	2,391	1,308	0	700	0	0	4,399
1994	2,391	1,308	0	700	0	0	4,399
1995	2,391	1,308	0	700	0	0	4,399
1996	2,391	1,308	0	700	0	0	4,399
1997	2,391	1,308	0	700	0	0	4,399
1998	2,391	1,308	0	700	0	0	4,399
1999	2,391	1,308	0	700	0	0	4,399
2000	2,391	1,308	0	700	0	0	4,399
2001	2,531	1,308	0	700	0	0	4,539
2002	2,671	1,308	0	700	0	0	4,679
2003	2,811	1,308	0	700	0	0	4,819
2004	2,951	1,308	0	700	0	0	4,959
2005	2,951	1,808	0	700	0	0	5,459
2006	2,851	1,808	0	700	0	0	5,359

TABLE A.18

NET SYSTEM CAPACITY AND RESERVE MARGINS
CITY PUBLIC SERVICE OF SAN ANTONIO
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	0	3,901	39.37%	15.00%	682
1992	0	0	0	4,399	54.38%	15.00%	1,122
1993	0	0	0	4,399	49.70%	15.00%	1,020
1994	0	0	0	4,399	44.43%	15.00%	896
1995	0	0	0	4,399	39.16%	15.00%	764
1996	0	0	0	4,399	34.28%	15.00%	631
1997	0	0	0	4,399	29.55%	15.00%	494
1998	0	0	0	4,399	25.05%	15.00%	353
1999	0	0	0	4,399	20.70%	15.00%	208
2000	0	0	0	4,399	16.48%	15.00%	56
2001	0	0	0	4,539	16.30%	15.00%	51
2002	0	0	0	4,679	16.34%	15.00%	54
2003	0	0	0	4,819	15.87%	15.00%	36
2004	0	0	0	4,959	15.26%	15.00%	11
2005	0	0	0	5,459	22.76%	15.00%	345
2006	0	0	0	5,359	15.32%	15.00%	15

TABLE A.19

PEAK DEMAND AND DEMAND ADJUSTMENTS
SOUTHWESTERN PUBLIC SERVICE COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1991	3,079	0	0	0	0	3,079
1992	3,027	8	(15)	0	(7)	3,021
1993	3,107	60	(54)	0	6	3,113
1994	3,184	58	(54)	0	4	3,188
1995	3,231	57	(54)	0	3	3,234
1996	3,287	109	(54)	0	55	3,342
1997	3,330	111	(54)	0	57	3,387
1998	3,375	112	(54)	0	58	3,433
1999	3,420	114	(54)	0	60	3,480
2000	3,465	116	(54)	0	62	3,527
2001	3,508	119	(54)	0	65	3,573
2002	3,555	119	(54)	0	65	3,620
2003	3,601	119	(54)	0	65	3,666
2004	3,647	119	(54)	0	65	3,712
2005	3,693	119	(54)	0	65	3,758
2006	3,739	119	(54)	0	65	3,804

TABLE A.20

INSTALLED CAPACITY
SOUTHWESTERN PUBLIC SERVICE COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	1,866	2,146	0	0	0	39	4,051
1992	1,876	2,146	0	0	0	39	4,061
1993	1,876	2,146	0	0	0	39	4,061
1994	1,876	2,146	0	0	0	39	4,061
1995	1,876	2,146	0	0	0	39	4,061
1996	1,876	2,146	0	0	0	39	4,061
1997	1,876	2,146	0	0	0	39	4,061
1998	1,876	2,146	0	0	0	39	4,061
1999	1,924	2,146	0	0	0	39	4,109
2000	1,974	2,146	0	0	0	39	4,159
2001	1,999	2,146	0	0	0	39	4,184
2002	1,999	2,146	0	0	0	39	4,184
2003	1,999	2,146	0	0	0	39	4,184
2004	1,999	2,146	0	0	0	39	4,184
2005	1,999	2,146	0	0	0	39	4,184
2006	1,999	2,146	0	0	0	39	4,184

TABLE A.21

NET SYSTEM CAPACITY AND RESERVE MARGINS
SOUTHWESTERN PUBLIC SERVICE COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	45	4,006	30.11%	15.00%	465
1992	0	0	81	3,981	31.78%	15.00%	507
1993	0	0	173	3,889	24.92%	15.00%	309
1994	0	0	213	3,848	20.73%	15.00%	183
1995	0	0	213	3,848	18.99%	15.00%	129
1996	36	0	253	3,844	15.01%	15.00%	0
1997	0	0	104	3,958	16.85%	15.00%	63
1998	1	0	115	3,947	14.99%	15.00%	0
1999	19	0	127	4,002	14.99%	15.00%	0
2000	23	0	127	4,056	15.00%	15.00%	0
2001	0	0	69	4,115	15.16%	15.00%	6
2002	0	0	12	4,172	15.26%	15.00%	9
2003	0	32	0	4,216	15.01%	15.00%	0
2004	0	84	0	4,268	14.99%	15.00%	0
2005	0	138	0	4,322	15.00%	15.00%	0
2006	0	191	0	4,375	15.01%	15.00%	0

TABLE A.22

PEAK DEMAND AND DEMAND ADJUSTMENTS
SOUTHWESTERN PUBLIC SERVICE COMPANY
STATE OF TEXAS DATA
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	2,282	0	0	0	0	2,282
1992	2,219	9	(15)	0	(6)	2,213
1993	2,288	61	(54)	0	7	2,295
1994	2,353	60	(54)	0	6	2,359
1995	2,391	60	(54)	0	6	2,397
1996	2,436	112	(54)	0	58	2,494
1997	2,473	114	(54)	0	60	2,532
1998	2,510	115	(54)	0	61	2,571
1999	2,548	117	(54)	0	63	2,610
2000	2,585	119	(54)	0	65	2,650
2001	2,621	122	(54)	0	68	2,689
2002	2,660	122	(54)	0	68	2,728
2003	2,699	122	(54)	0	68	2,767
2004	2,738	122	(54)	0	68	2,806
2005	2,778	122	(54)	0	68	2,846
2006	2,817	122	(54)	0	68	2,885

TABLE A.23

INSTALLED CAPACITY
SOUTHWESTERN PUBLIC SERVICE COMPANY
STATE OF TEXAS DATA
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	1,383	1,591	0	0	0	29	3,002
1992	1,374	1,572	0	0	0	29	2,975
1993	1,383	1,582	0	0	0	29	2,994
1994	1,389	1,588	0	0	0	29	3,006
1995	1,390	1,590	0	0	0	29	3,010
1996	1,400	1,601	0	0	0	29	3,030
1997	1,403	1,605	0	0	0	29	3,036
1998	1,405	1,607	0	0	0	29	3,042
1999	1,443	1,610	0	0	0	29	3,082
2000	1,483	1,612	0	0	0	29	3,125
2001	1,504	1,615	0	0	0	29	3,148
2002	1,507	1,617	0	0	0	29	3,153
2003	1,509	1,620	0	0	0	29	3,158
2004	1,511	1,622	0	0	0	29	3,163
2005	1,514	1,625	0	0	0	30	3,168
2006	1,516	1,627	0	0	0	30	3,173

TABLE A.24

NET SYSTEM CAPACITY AND RESERVE MARGINS
SOUTHWESTERN PUBLIC SERVICE COMPANY
STATE OF TEXAS DATA
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	33	2,969	30.11%	15.00%	345
1992	0	0	59	2,916	31.78%	15.00%	371
1993	0	0	127	2,867	24.92%	15.00%	228
1994	0	0	157	2,848	20.73%	15.00%	135
1995	0	0	158	2,852	18.99%	15.00%	96
1996	27	0	189	2,868	15.01%	15.00%	0
1997	0	0	77	2,959	16.85%	15.00%	47
1998	1	0	86	2,956	14.99%	15.00%	0
1999	14	0	95	3,002	14.99%	15.00%	0
2000	17	0	95	3,047	15.00%	15.00%	0
2001	0	0	52	3,097	15.16%	15.00%	4
2002	0	0	9	3,144	15.26%	15.00%	7
2003	0	24	0	3,183	15.01%	15.00%	0
2004	0	64	0	3,227	14.99%	15.00%	0
2005	0	104	0	3,272	15.00%	15.00%	0
2006	0	145	0	3,318	15.01%	15.00%	0

TABLE A.25

PEAK DEMAND AND DEMAND ADJUSTMENTS
SOUTHWESTERN ELECTRIC POWER COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	2,915	0	0	0	0	2,915
1992	3,112	(5)	(61)	0	(66)	3,045
1993	3,209	(11)	(61)	0	(72)	3,137
1994	3,367	(19)	(61)	0	(80)	3,287
1995	3,506	(25)	(61)	(1)	(86)	3,420
1996	3,592	(30)	(61)	(1)	(92)	3,500
1997	3,715	(36)	(61)	(1)	(98)	3,617
1998	3,793	(42)	(61)	(1)	(104)	3,688
1999	3,870	(42)	(61)	(2)	(105)	3,765
2000	3,965	(42)	(61)	(2)	(105)	3,860
2001	4,036	(42)	(61)	(2)	(105)	3,930
2002	4,111	(42)	(61)	(3)	(106)	4,005
2003	4,186	(42)	(61)	(3)	(106)	4,080
2004	4,257	(42)	(61)	(3)	(106)	4,150
2005	4,327	(42)	(61)	(4)	(107)	4,221
2006	4,398	(42)	(61)	(4)	(107)	4,290

TABLE A.26

INSTALLED CAPACITY
SOUTHWESTERN ELECTRIC POWER COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	1,819	1,824	821	0	0	0	4,464
1992	1,819	1,824	821	0	0	0	4,464
1993	1,819	1,824	821	0	0	0	4,464
1994	1,819	1,824	821	0	0	0	4,464
1995	1,819	1,824	821	0	0	0	4,464
1996	1,819	1,824	821	0	0	0	4,464
1997	1,819	1,824	821	0	0	0	4,464
1998	1,819	1,824	821	0	0	0	4,464
1999	1,819	1,824	821	0	0	0	4,464
2000	1,819	1,824	821	0	0	0	4,464
2001	1,850	1,824	821	0	0	0	4,495
2002	1,863	1,824	821	0	0	0	4,508
2003	1,943	1,824	821	0	0	0	4,588
2004	2,073	1,824	821	0	0	0	4,718
2005	2,153	1,824	821	0	0	0	4,798
2006	2,214	1,824	821	0	0	0	4,859

TABLE A.27

NET SYSTEM CAPACITY AND RESERVE MARGINS
SOUTHWESTERN ELECTRIC POWER COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	26	4,438	52.26%	15.00%	1,086
1992	16	0	61	4,419	45.10%	15.00%	917
1993	16	0	26	4,454	41.96%	15.00%	846
1994	16	0	21	4,459	35.67%	15.00%	679
1995	16	0	28	4,452	30.16%	15.00%	519
1996	16	0	46	4,434	26.69%	15.00%	409
1997	16	0	54	4,426	22.37%	15.00%	266
1998	16	0	111	4,369	18.45%	15.00%	127
1999	16	0	123	4,357	15.72%	15.00%	27
2000	31	5	60	4,440	15.01%	15.00%	0
2001	56	5	36	4,520	15.00%	15.00%	0
2002	114	5	21	4,606	15.00%	15.00%	0
2003	121	5	21	4,693	15.01%	15.00%	0
2004	81	5	31	4,773	15.00%	15.00%	0
2005	72	5	21	4,854	15.00%	15.00%	0
2006	99	5	29	4,934	14.99%	15.00%	0

TABLE A.28

PEAK DEMAND AND DEMAND ADJUSTMENTS
SOUTHWESTERN ELECTRIC POWER COMPANY
STATE OF TEXAS DATA
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1991	1,640	0	0	0	0	1,640
1992	1,768	(2)	(58)	0	(60)	1,707
1993	1,829	(4)	(58)	0	(63)	1,766
1994	1,947	(7)	(58)	0	(66)	1,881
1995	2,042	(9)	(58)	(1)	(68)	1,973
1996	2,096	(11)	(58)	(1)	(71)	2,025
1997	2,190	(14)	(58)	(1)	(73)	2,117
1998	2,238	(16)	(58)	(1)	(75)	2,162
1999	2,286	(16)	(58)	(2)	(76)	2,210
2000	2,353	(16)	(58)	(2)	(76)	2,277
2001	2,395	(16)	(58)	(2)	(76)	2,318
2002	2,442	(16)	(58)	(3)	(77)	2,365
2003	2,489	(16)	(58)	(3)	(77)	2,412
2004	2,530	(16)	(58)	(3)	(77)	2,452
2005	2,571	(16)	(58)	(4)	(78)	2,493
2006	2,612	(16)	(58)	(4)	(78)	2,534

TABLE A.29

INSTALLED CAPACITY
SOUTHWESTERN ELECTRIC POWER COMPANY
STATE OF TEXAS DATA
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	1,023	1,026	462	0	0	0	2,512
1992	1,020	1,023	460	0	0	0	2,503
1993	1,024	1,027	462	0	0	0	2,513
1994	1,041	1,044	470	0	0	0	2,555
1995	1,050	1,052	474	0	0	0	2,576
1996	1,053	1,055	475	0	0	0	2,583
1997	1,065	1,067	480	0	0	0	2,612
1998	1,067	1,069	481	0	0	0	2,617
1999	1,068	1,071	482	0	0	0	2,621
2000	1,073	1,076	484	0	0	0	2,633
2001	1,091	1,076	484	0	0	0	2,652
2002	1,100	1,077	485	0	0	0	2,662
2003	1,148	1,078	485	0	0	0	2,712
2004	1,225	1,078	485	0	0	0	2,788
2005	1,272	1,078	485	0	0	0	2,835
2006	1,308	1,077	485	0	0	0	2,870

TABLE A.30

NET SYSTEM CAPACITY AND RESERVE MARGINS
SOUTHWESTERN ELECTRIC POWER COMPANY
STATE OF TEXAS DATA
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	15	2,497	52.26%	15.00%	611
1992	9	0	34	2,477	45.10%	15.00%	514
1993	9	0	15	2,508	41.96%	15.00%	476
1994	9	0	12	2,552	35.67%	15.00%	389
1995	9	0	16	2,569	30.16%	15.00%	299
1996	9	0	27	2,565	26.69%	15.00%	237
1997	9	0	32	2,590	22.37%	15.00%	156
1998	9	0	65	2,562	18.45%	15.00%	75
1999	9	0	72	2,558	15.72%	15.00%	16
2000	18	3	35	2,619	15.01%	15.00%	0
2001	33	3	21	2,666	15.00%	15.00%	0
2002	67	3	12	2,720	15.00%	15.00%	0
2003	71	3	12	2,774	15.01%	15.00%	0
2004	48	3	18	2,820	15.00%	15.00%	0
2005	42	3	12	2,868	15.00%	15.00%	0
2006	58	3	17	2,914	14.99%	15.00%	0

TABLE A.31

PEAK DEMAND AND DEMAND ADJUSTMENTS
LOWER COLORADO RIVER AUTHORITY
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	1,601	0	0	0	0	1,601
1992	1,690	(2)	(106)	(2)	(110)	1,580
1993	1,732	(6)	(107)	(5)	(118)	1,613
1994	1,779	(10)	(107)	(8)	(126)	1,654
1995	1,829	(13)	(107)	(11)	(132)	1,698
1996	1,882	(17)	(110)	(15)	(142)	1,739
1997	1,937	(19)	(117)	(19)	(155)	1,783
1998	1,993	(22)	(126)	(23)	(171)	1,822
1999	2,046	(22)	(133)	(27)	(182)	1,864
2000	2,093	(22)	(146)	(30)	(198)	1,895
2001	2,135	(22)	(146)	(34)	(202)	1,933
2002	2,176	(22)	(146)	(38)	(206)	1,970
2003	2,217	(22)	(146)	(42)	(210)	2,007
2004	2,259	(22)	(146)	(45)	(213)	2,046
2005	2,302	(22)	(146)	(49)	(217)	2,085
2006	2,345	(22)	(146)	(53)	(221)	2,124

TABLE A.32

INSTALLED CAPACITY
LOWER COLORADO RIVER AUTHORITY
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	1,025	1,000	0	0	241	0	2,266
1992	1,025	1,000	0	0	241	0	2,266
1993	1,025	1,000	0	0	241	0	2,266
1994	1,025	1,000	0	0	241	0	2,266
1995	1,025	1,000	0	0	241	0	2,266
1996	1,025	1,000	0	0	241	0	2,266
1997	1,025	1,000	0	0	241	0	2,266
1998	1,025	1,000	0	0	241	0	2,266
1999	1,025	1,000	0	0	241	0	2,266
2000	1,025	1,000	0	0	241	0	2,266
2001	1,025	1,000	0	0	241	0	2,266
2002	1,025	1,000	0	0	241	0	2,266
2003	1,025	1,000	0	0	241	0	2,266
2004	1,025	1,000	0	0	241	0	2,266
2005	1,025	1,000	0	0	241	0	2,266
2006	1,025	1,000	0	0	241	0	2,266

TABLE A.33

NET SYSTEM CAPACITY AND RESERVE MARGINS
LOWER COLORADO RIVER AUTHORITY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	0	2,266	41.54%	15.00%	425
1992	0	0	0	2,266	43.44%	15.00%	449
1993	0	0	0	2,266	40.46%	15.00%	411
1994	0	0	0	2,266	37.00%	15.00%	364
1995	0	0	0	2,266	33.49%	15.00%	314
1996	0	0	0	2,266	30.28%	15.00%	266
1997	0	0	0	2,266	27.10%	15.00%	216
1998	0	0	0	2,266	24.37%	15.00%	171
1999	0	0	0	2,266	21.56%	15.00%	122
2000	0	0	0	2,266	19.60%	15.00%	87
2001	0	0	0	2,266	17.20%	15.00%	43
2002	0	0	0	2,266	15.02%	15.00%	0
2003	0	42	0	2,308	15.00%	15.00%	0
2004	0	86	0	2,352	14.98%	15.00%	0
2005	0	132	0	2,398	15.01%	15.00%	0
2006	0	177	0	2,443	15.01%	15.00%	0

TABLE A.34

PEAK DEMAND AND DEMAND ADJUSTMENTS
CITY OF AUSTIN ELECTRIC UTILITY
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1991	1,457	0	0	0	0	1,457
1992	1,597	0	(4)	(29)	(33)	1,564
1993	1,656	0	(6)	(39)	(45)	1,611
1994	1,703	0	(8)	(59)	(67)	1,636
1995	1,750	0	(11)	(72)	(83)	1,667
1996	1,808	0	(15)	(90)	(105)	1,703
1997	1,871	0	(19)	(108)	(127)	1,744
1998	1,934	0	(24)	(127)	(151)	1,783
1999	1,992	0	(29)	(147)	(176)	1,816
2000	2,050	0	(34)	(169)	(203)	1,847
2001	2,104	0	(39)	(188)	(227)	1,877
2002	2,161	0	(45)	(206)	(251)	1,910
2003	2,220	0	(47)	(229)	(276)	1,944
2004	2,280	0	(49)	(255)	(304)	1,976
2005	2,341	0	(50)	(276)	(326)	2,015
2006	2,400	0	(51)	(299)	(350)	2,050

TABLE A.35

INSTALLED CAPACITY
CITY OF AUSTIN ELECTRIC UTILITY
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	1,450	585	0	400	0	1	2,436
1992	1,450	585	0	400	0	1	2,436
1993	1,450	585	0	400	0	1	2,436
1994	1,450	585	0	400	0	1	2,436
1995	1,450	585	0	400	0	1	2,436
1996	1,450	585	0	400	0	1	2,436
1997	1,450	585	0	400	0	1	2,436
1998	1,450	585	0	400	0	1	2,436
1999	1,450	585	0	400	0	1	2,436
2000	1,450	585	0	400	0	1	2,436
2001	1,450	585	0	400	0	1	2,436
2002	1,450	585	0	400	0	1	2,436
2003	1,450	585	0	400	0	1	2,436
2004	1,450	585	0	400	0	1	2,436
2005	1,450	585	0	400	0	1	2,436
2006	1,450	585	0	400	0	1	2,436

TABLE A.36

NET SYSTEM CAPACITY AND RESERVE MARGINS
CITY OF AUSTIN ELECTRIC UTILITY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	25	2,411	65.45%	15.00%	735
1992	0	0	25	2,411	54.09%	15.00%	612
1993	0	0	25	2,411	49.62%	15.00%	558
1994	0	0	25	2,411	47.34%	15.00%	529
1995	0	0	25	2,411	44.59%	15.00%	493
1996	0	0	25	2,411	41.57%	15.00%	452
1997	0	0	0	2,436	39.64%	15.00%	430
1998	0	0	0	2,436	36.62%	15.00%	385
1999	0	0	0	2,436	34.09%	15.00%	347
2000	0	0	0	2,436	31.86%	15.00%	311
2001	0	0	0	2,436	29.73%	15.00%	277
2002	0	0	0	2,436	27.49%	15.00%	239
2003	0	0	0	2,436	25.27%	15.00%	200
2004	0	0	0	2,436	23.28%	15.00%	164
2005	0	0	0	2,436	20.89%	15.00%	119
2006	0	0	0	2,436	18.81%	15.00%	78

TABLE A.37

PEAK DEMAND AND DEMAND ADJUSTMENTS
WEST TEXAS UTILITIES COMPANY
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	1,097	0	0	0	0	1,097
1992	1,131	(1)	0	(1)	(2)	1,129
1993	1,239	(3)	0	(3)	(6)	1,233
1994	1,217	(5)	0	(4)	(9)	1,208
1995	1,230	(6)	0	(5)	(11)	1,218
1996	1,264	(8)	0	(7)	(15)	1,250
1997	1,300	(9)	0	(8)	(17)	1,283
1998	1,336	(10)	0	(9)	(19)	1,316
1999	1,372	(10)	0	(11)	(21)	1,351
2000	1,408	(10)	0	(12)	(22)	1,386
2001	1,442	(10)	0	(14)	(24)	1,418
2002	1,468	(10)	0	(15)	(25)	1,443
2003	1,494	(10)	0	(17)	(27)	1,467
2004	1,519	(10)	0	(18)	(28)	1,491
2005	1,558	(10)	0	(20)	(30)	1,528
2006	1,597	(10)	0	(21)	(31)	1,565

TABLE A.38

INSTALLED CAPACITY
WEST TEXAS UTILITIES COMPANY
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	1,020	364	0	0	0	0	1,384
1992	1,024	375	0	0	0	0	1,399
1993	1,024	375	0	0	0	0	1,399
1994	1,024	375	0	0	0	0	1,399
1995	1,024	375	0	0	0	0	1,399
1996	1,024	375	0	0	0	0	1,399
1997	1,024	375	0	0	0	0	1,399
1998	982	375	0	0	0	0	1,357
1999	982	375	0	0	0	0	1,357
2000	1,177	375	0	0	0	0	1,552
2001	1,177	375	0	0	0	0	1,552
2002	1,264	375	0	0	0	0	1,639
2003	1,231	375	0	0	0	0	1,606
2004	1,231	375	0	0	0	0	1,606
2005	1,144	375	0	0	0	0	1,519
2006	1,258	375	0	0	0	0	1,633

TABLE A.39

NET SYSTEM CAPACITY AND RESERVE MARGINS
WEST TEXAS UTILITIES COMPANY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	12	0	0	1,396	27.26%	15.00%	134
1992	5	0	0	1,404	24.38%	15.00%	106
1993	19	0	0	1,418	14.97%	15.00%	0
1994	0	0	0	1,399	15.77%	15.00%	9
1995	12	0	0	1,411	15.82%	15.00%	10
1996	42	0	0	1,441	15.32%	15.00%	4
1997	76	0	0	1,475	15.01%	15.00%	0
1998	157	0	0	1,514	15.02%	15.00%	0
1999	197	0	0	1,554	15.00%	15.00%	0
2000	27	17	2	1,594	15.02%	15.00%	0
2001	27	81	0	1,660	17.06%	15.00%	29
2002	0	102	39	1,702	17.92%	15.00%	42
2003	0	102	0	1,708	16.41%	15.00%	21
2004	0	141	2	1,745	17.06%	15.00%	31
2005	38	200	0	1,757	14.97%	15.00%	0
2006	0	200	18	1,815	15.94%	15.00%	15

TABLE A.40

PEAK DEMAND AND DEMAND ADJUSTMENTS
EL PASO ELECTRIC COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	936	0	0	0	0	936
1992	992	(1)	0	(1)	(2)	990
1993	1,015	(1)	0	(3)	(4)	1,011
1994	1,040	(2)	0	(4)	(6)	1,034
1995	1,066	(3)	0	(6)	(9)	1,057
1996	1,094	(3)	0	(8)	(11)	1,083
1997	1,122	(3)	0	(10)	(13)	1,109
1998	1,151	(4)	0	(12)	(16)	1,135
1999	1,180	(4)	0	(13)	(17)	1,163
2000	1,208	(4)	0	(15)	(19)	1,189
2001	1,237	(4)	0	(17)	(21)	1,216
2002	1,266	(4)	0	(19)	(23)	1,243
2003	1,295	(4)	0	(21)	(25)	1,270
2004	1,323	(4)	0	(23)	(27)	1,296
2005	1,353	(4)	0	(24)	(28)	1,325
2006	1,382	(4)	0	(26)	(30)	1,352

TABLE A.41

INSTALLED CAPACITY
EL PASO ELECTRIC COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	793	104	0	600	0	0	1,497
1992	793	104	0	600	0	0	1,497
1993	793	104	0	600	0	0	1,497
1994	793	104	0	600	0	0	1,497
1995	793	104	0	600	0	0	1,497
1996	793	104	0	600	0	0	1,497
1997	793	104	0	600	0	0	1,497
1998	793	104	0	600	0	0	1,497
1999	793	104	0	600	0	0	1,497
2000	793	104	0	600	0	0	1,497
2001	873	104	0	600	0	0	1,577
2002	873	104	0	600	0	0	1,577
2003	873	104	0	600	0	0	1,577
2004	873	104	0	600	0	0	1,577
2005	873	104	0	600	0	0	1,577
2006	873	104	0	600	0	0	1,577

TABLE A.42

NET SYSTEM CAPACITY AND RESERVE MARGINS
EL PASO ELECTRIC COMPANY
TOTAL SYSTEM DATA
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	208	1,289	37.71%	22.00%	147
1992	50	0	331	1,216	22.85%	21.00%	18
1993	100	0	336	1,261	24.67%	21.00%	37
1994	100	0	332	1,265	22.38%	20.00%	25
1995	130	0	332	1,295	22.54%	20.00%	27
1996	170	0	332	1,335	23.27%	20.00%	35
1997	50	0	178	1,369	23.42%	20.00%	38
1998	100	0	178	1,419	24.98%	20.00%	57
1999	102	0	178	1,421	22.23%	20.00%	26
2000	107	0	178	1,426	19.96%	20.00%	0
2001	100	0	178	1,499	23.28%	20.00%	40
2002	109	0	178	1,508	21.31%	20.00%	16
2003	100	0	76	1,601	26.04%	20.00%	77
2004	100	0	76	1,601	23.49%	20.00%	45
2005	100	0	76	1,601	20.87%	20.00%	11
2006	121	0	76	1,622	19.99%	20.00%	0

TABLE A.43

PEAK DEMAND AND DEMAND ADJUSTMENTS
EL PASO ELECTRIC COMPANY
STATE OF TEXAS DATA
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	757	0	0	0	0	757
1992	791	(1)	0	(1)	(2)	789
1993	807	(1)	0	(3)	(4)	803
1994	826	(2)	0	(4)	(6)	820
1995	846	(3)	0	(6)	(9)	837
1996	867	(3)	0	(8)	(11)	856
1997	888	(3)	0	(10)	(13)	875
1998	910	(4)	0	(12)	(16)	894
1999	932	(4)	0	(13)	(17)	915
2000	953	(4)	0	(15)	(19)	934
2001	975	(4)	0	(17)	(21)	954
2002	997	(4)	0	(19)	(23)	974
2003	1,019	(4)	0	(21)	(25)	994
2004	1,040	(4)	0	(23)	(27)	1,013
2005	1,062	(4)	0	(24)	(28)	1,034
2006	1,085	(4)	0	(26)	(30)	1,055

TABLE A.44

INSTALLED CAPACITY
EL PASO ELECTRIC COMPANY
STATE OF TEXAS DATA
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	641	84	0	485	0	0	1,211
1992	632	83	0	478	0	0	1,193
1993	630	83	0	477	0	0	1,189
1994	629	82	0	476	0	0	1,187
1995	628	82	0	475	0	0	1,185
1996	627	82	0	474	0	0	1,183
1997	626	82	0	473	0	0	1,181
1998	625	82	0	473	0	0	1,179
1999	624	82	0	472	0	0	1,178
2000	623	82	0	471	0	0	1,176
2001	685	82	0	471	0	0	1,237
2002	684	81	0	470	0	0	1,236
2003	683	81	0	470	0	0	1,234
2004	682	81	0	469	0	0	1,233
2005	681	81	0	468	0	0	1,231
2006	681	81	0	468	0	0	1,231

TABLE A.45

NET SYSTEM CAPACITY AND RESERVE MARGINS
EL PASO ELECTRIC COMPANY
STATE OF TEXAS DATA
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	0	0	168	1,042	37.71%	22.00%	119
1992	40	0	264	969	22.85%	21.00%	15
1993	79	0	267	1,002	24.67%	21.00%	29
1994	79	0	263	1,003	22.38%	20.00%	20
1995	103	0	263	1,025	22.54%	20.00%	21
1996	134	0	262	1,055	23.27%	20.00%	28
1997	39	0	140	1,080	23.42%	20.00%	30
1998	79	0	140	1,118	24.98%	20.00%	45
1999	80	0	140	1,118	22.23%	20.00%	20
2000	84	0	140	1,120	19.96%	20.00%	0
2001	78	0	140	1,176	23.28%	20.00%	31
2002	85	0	139	1,182	21.31%	20.00%	13
2003	78	0	59	1,253	26.04%	20.00%	60
2004	78	0	59	1,252	23.49%	20.00%	35
2005	78	0	59	1,249	20.87%	20.00%	9
2006	94	0	59	1,266	19.99%	20.00%	0

TABLE A.46

PEAK DEMAND AND DEMAND ADJUSTMENTS
TEXAS-NEW MEXICO POWER COMPANY
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Active DSM	Passive DSM	Total	Peak Demand After Adjustments
1991	478	0	0	0	0	478
1992	624	(2)	0	(2)	(4)	620
1993	633	(4)	0	(4)	(8)	625
1994	641	(6)	0	(6)	(12)	629
1995	608	(8)	0	(8)	(16)	592
1996	634	(9)	0	(10)	(19)	615
1997	651	(11)	0	(12)	(23)	628
1998	666	(12)	0	(14)	(26)	640
1999	679	(12)	0	(16)	(28)	651
2000	684	(12)	0	(18)	(30)	654
2001	812	(12)	0	(18)	(30)	782
2002	813	(12)	0	(18)	(30)	783
2003	804	(12)	0	(18)	(30)	774
2004	796	(12)	0	(18)	(30)	766
2005	766	(12)	0	(18)	(30)	736
2006	766	(12)	0	(18)	(30)	736

TABLE A.47

INSTALLED CAPACITY
TEXAS-NEW MEXICO POWER COMPANY
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	0	0	144	0	0	0	144
1992	0	0	293	0	0	0	293
1993	0	0	293	0	0	0	293
1994	0	0	293	0	0	0	293
1995	0	0	293	0	0	0	293
1996	0	0	293	0	0	0	293
1997	0	0	293	0	0	0	293
1998	0	0	293	0	0	0	293
1999	0	0	293	0	0	0	293
2000	0	0	293	0	0	0	293
2001	0	0	293	0	0	0	293
2002	0	0	293	0	0	0	293
2003	0	0	293	0	0	0	293
2004	0	0	293	0	0	0	293
2005	0	0	293	0	0	0	293
2006	0	0	293	0	0	0	293

TABLE A.48

NET SYSTEM CAPACITY AND RESERVE MARGINS
TEXAS-NEW MEXICO POWER COMPANY
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin(*) (%)	Target Reserve (%)	Excess Capacity
1991	0	335	0	479	0.00%	0.00%	1
1992	0	327	0	620	0.00%	0.00%	0
1993	0	332	0	625	0.00%	0.00%	0
1994	0	338	0	631	0.00%	0.00%	2
1995	0	299	0	592	0.00%	0.00%	0
1996	0	322	0	615	0.00%	0.00%	0
1997	0	336	0	629	0.00%	0.00%	1
1998	0	350	0	643	0.55%	0.00%	3
1999	0	364	0	657	0.86%	0.00%	6
2000	0	373	0	666	1.81%	0.00%	12
2001	28	461	0	782	0.00%	0.00%	0
2002	19	471	0	783	0.00%	0.00%	0
2003	7	474	0	774	0.00%	0.00%	0
2004	0	473	0	766	0.00%	0.00%	0
2005	0	443	0	736	0.00%	0.00%	0
2006	0	443	0	736	0.00%	0.00%	0

* - TNP reserves are included with purchased power.

TABLE A.49

PEAK DEMAND AND DEMAND ADJUSTMENTS
BRAZOS ELECTRIC POWER COOPERATIVE, INC.
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	857	0	0	0	0	857
1992	945	(2)	0	0	(2)	943
1993	981	(4)	0	(1)	(5)	976
1994	1,022	(5)	0	(2)	(7)	1,015
1995	1,066	(7)	0	(3)	(10)	1,055
1996	1,110	(8)	0	(5)	(13)	1,097
1997	1,152	(10)	0	(7)	(17)	1,135
1998	1,192	(11)	0	(9)	(20)	1,171
1999	1,230	(11)	0	(12)	(23)	1,207
2000	1,267	(11)	0	(14)	(25)	1,242
2001	1,304	(11)	0	(16)	(27)	1,277
2002	1,342	(11)	0	(19)	(30)	1,312
2003	1,379	(11)	0	(21)	(32)	1,347
2004	1,418	(11)	0	(23)	(34)	1,383
2005	1,456	(11)	0	(26)	(37)	1,419
2006	1,494	(11)	0	(29)	(40)	1,454

TABLE A.50

INSTALLED CAPACITY
BRAZOS ELECTRIC POWER COOPERATIVE, INC.
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	467	0	0	0	0	0	467
1992	467	0	0	0	0	0	467
1993	467	0	0	0	0	0	467
1994	675	0	0	0	0	0	675
1995	675	0	0	0	0	0	675
1996	675	0	0	0	0	0	675
1997	779	0	0	0	0	0	779
1998	779	0	0	0	0	0	779
1999	779	0	0	0	0	0	779
2000	883	0	0	0	0	0	883
2001	987	0	0	0	0	0	987
2002	987	0	0	0	0	0	987
2003	1,091	0	0	0	0	0	1,091
2004	1,091	0	0	0	0	0	1,091
2005	1,091	0	0	0	0	0	1,091
2006	1,091	0	0	0	0	0	1,091

TABLE A.51

NET SYSTEM CAPACITY AND RESERVE MARGINS
BRAZOS ELECTRIC POWER COOPERATIVE, INC.
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	507	0	7	967	12.84%	12.90%	(1)
1992	606	0	0	1,073	13.81%	13.80%	0
1993	677	0	0	1,144	17.17%	13.80%	33
1994	504	0	0	1,179	16.14%	13.80%	24
1995	538	0	0	1,213	14.93%	13.80%	12
1996	574	0	0	1,249	13.82%	13.80%	0
1997	313	200	0	1,292	13.86%	13.80%	1
1998	354	200	0	1,333	13.82%	13.80%	0
1999	395	200	0	1,374	13.83%	13.80%	0
2000	330	200	0	1,413	13.78%	13.80%	0
2001	266	200	0	1,453	13.78%	13.80%	0
2002	306	200	0	1,493	13.78%	13.80%	0
2003	242	200	0	1,533	13.77%	13.80%	0
2004	283	200	0	1,574	13.79%	13.80%	0
2005	324	200	0	1,615	13.80%	13.80%	0
2006	364	200	0	1,655	13.79%	13.80%	0

TABLE A.52

PEAK DEMAND AND DEMAND ADJUSTMENTS
TOTAL OTHER UTILITIES
(MW)

Year	Peak Demand Before Adjustments	Demand Adjustments: Exogenous Factors	Demand Adjustments: Active DSM	Demand Adjustments: Passive DSM	Demand Adjustments: Total	Peak Demand After Adjustments
1991	1,977	0	0	0	0	1,977
1992	2,147	0	(4)	0	(4)	2,143
1993	2,238	0	(9)	0	(9)	2,229
1994	2,305	0	(15)	0	(15)	2,290
1995	2,407	0	(20)	0	(20)	2,387
1996	2,470	0	(27)	0	(27)	2,443
1997	2,534	0	(33)	0	(33)	2,501
1998	2,600	0	(40)	0	(40)	2,560
1999	2,676	0	(48)	0	(48)	2,628
2000	2,749	0	(56)	0	(56)	2,693
2001	2,830	0	(65)	0	(65)	2,765
2002	2,916	0	(75)	0	(75)	2,841
2003	2,998	0	(75)	0	(75)	2,923
2004	3,095	0	(75)	0	(75)	3,020
2005	3,194	0	(75)	0	(75)	3,119
2006	3,296	0	(75)	0	(75)	3,221

TABLE A.53

INSTALLED CAPACITY
TOTAL OTHER UTILITIES
(MW)

Year	Total Natural Gas/Oil	Coal	Lignite	Nuclear	Hydro	Alternative Energy Sources	Total Installed Generating Capacity
1991	1,450	233	910	0	395	0	2,988
1992	1,450	233	910	0	395	0	2,988
1993	1,450	233	910	0	395	0	2,988
1994	1,460	233	910	0	395	0	2,998
1995	1,460	233	910	0	395	10	3,008
1996	1,460	233	910	0	395	10	3,008
1997	1,460	233	910	0	395	10	3,008
1998	1,460	233	910	0	395	10	3,008
1999	1,660	233	910	0	395	10	3,208
2000	1,660	283	910	0	395	10	3,258
2001	1,660	283	910	0	395	10	3,258
2002	1,660	283	910	0	395	10	3,258
2003	1,660	283	910	0	395	10	3,258
2004	1,660	283	910	0	395	10	3,258
2005	1,660	283	910	0	395	10	3,258
2006	1,660	283	910	0	395	10	3,258

TABLE A.54

NET SYSTEM CAPACITY AND RESERVE MARGINS
TOTAL OTHER UTILITIES
(MW)

Year	Firm Purchases From Utilities	Firm Purchases From Non-Utilities	Firm Off-System Sales	Net System Capacity	Reserve Margin (%)	Target Reserve (%)	Excess Capacity
1991	481	0	749	2,721	37.60%	15.00%	447
1992	501	0	762	2,727	27.26%	15.00%	263
1993	533	0	813	2,709	21.53%	15.00%	145
1994	561	0	760	2,800	22.23%	15.00%	166
1995	619	0	730	2,897	21.39%	15.00%	152
1996	625	0	675	2,958	21.07%	15.00%	148
1997	639	0	637	3,010	20.33%	15.00%	133
1998	665	0	605	3,068	19.85%	15.00%	124
1999	694	0	628	3,274	24.57%	15.00%	252
2000	689	0	627	3,320	23.30%	15.00%	223
2001	693	0	583	3,368	21.81%	15.00%	188
2002	716	0	583	3,391	19.35%	15.00%	124
2003	745	0	583	3,420	17.02%	15.00%	59
2004	784	60	583	3,519	16.52%	15.00%	46
2005	855	100	583	3,630	16.37%	15.00%	43
2006	970	100	583	3,745	16.28%	15.00%	41

APPENDIX B

Staff Derived Annual Sales by Sector

TABLE B.1

TOTAL TEXAS

ANNUAL SALES BY SECTOR (MWH)

AS DERIVED BY STAFF

YEAR	Residential Adjusted (MWH)	Commercial Adjusted (MWH)	Industrial Adjusted (MWH)	Other (MWH)	Total (MWH)
1991	69,288,816	53,219,998	36,991,319	81,538,176	241,038,308
1992	69,643,597	54,102,829	82,128,471	37,891,082	243,765,979
1993	71,044,456	55,564,974	84,561,554	39,866,455	251,037,439
1994	72,956,849	57,364,008	86,239,568	40,991,015	257,551,440
1995	74,879,849	59,436,781	88,205,153	42,206,068	264,727,852
1996	76,961,763	61,602,127	90,304,678	43,657,165	272,525,733
1997	78,951,097	63,533,239	92,175,750	44,777,840	279,437,926
1998	80,744,551	65,094,103	94,414,874	45,815,654	286,069,182
1999	82,630,369	66,765,745	96,514,584	46,903,350	292,814,049
2000	84,391,242	68,423,243	98,676,337	48,080,848	299,571,670
2001	86,178,440	70,002,551	101,021,297	49,117,447	306,319,735
2002	88,010,526	71,747,547	103,437,590	50,321,166	313,516,829
2003	89,574,355	73,210,072	106,039,230	51,366,800	320,190,457
2004	91,128,740	74,690,729	108,412,119	52,471,437	326,703,025
2005	92,436,243	76,184,231	110,615,217	53,574,305	332,809,996
2006	93,918,484	77,610,988	113,400,197	54,686,781	339,616,449