LONG-TERM ELECTRIC PEAK DEMAND

AND CAPACITY RESOURCE FORECAST

FOR TEXAS

1992

TECHNICAL APPENDICES

APRIL 1993

THE PUBLIC UTILITY COMMISSION OF TEXAS

CONTRIBUTORS

This report was prepared by the following staff members of the Public Utility Commission of Texas:

<u>Acting Director, Electric Division :</u>
Harold Hughes, P.E.

<u>Manager, Economic Analysis & Strategic Planning:</u>
Parviz Adib, Ph.D.

<u>Project Coordinator:</u>
Damayanti Ghosh, Ph.D.

Contributors:

Richard Bachmeier	Danielle Jaussaud
Daniel Bivens	Leszek Kasprowicz
Eduardo Budet	Kathleen North
Joe Castleberry	Sarut Panjavan
Doris Gayle	Evan Rowe
Sid Guermouche, Ph.D.	Gary M. Torrent, Ph.D.
Richard House	Nat Treadway

ABSTRACT

More than adequate electrical generating capacity exists to meet demand in the short term in Texas. This offers high reliability, but also imposes the cost of plant investments. Despite these near-term capacity surpluses, a number of resource planning issues deserve prompt attention:

1. Alleviate transmission bottlenecks.
2. Moderate near-term rate increases to prevent widespread self-generation or bypass.
3. Scrutinize promotional activities.
4. Examine end-use energy efficiency programs.
5. Research solar and wind technologies.
6. Consider dispersed resources to defer investments in transmission and distribution system upgrades.

The **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas 1992** is designed to provide information and recommendations to policy makers and others interested in the present and future status of the Texas electric power industry. Volume I of this two-volume report provides staff-recommended electricity demand projections for 13 of the state's largest generating utilities and a capacity resource plan for Texas. The economic outlook for Texas, fuel markets, cogeneration activity, demand-side management program impacts, environmental issues, and strategic rate design are highlighted. Substantial emphasis is placed on alternative power sources (particularly purchases from qualifying facilities) and energy efficiency to reduce the rate of growth of peak demand. The current report recognizes the end of the late 1980s economic recession in Texas, yet emphasizes efficiency improvements as the key to reliable and low-cost electrical services, environmental integrity, and increased economic growth.

Volume II summarizes the electricity demand forecasts, energy efficiency plans, and capacity resource plans developed by generating electric utilities and filed at the Commission in December 1991 (or later amended). The technical appendices provide a description of the staff's econometric electricity demand forecasting and resource planning system used to develop the load forecast contained in Volume I, and are available upon request.

TABLE OF CONTENTS

TECHNICAL APPENDICES

LONG-TERM ELECTRIC PEAK DEMAND

AND CAPACITY RESOURCE FORECAST

FOR TEXAS

1992

TECHNICAL APPENDIX

TO

PUCT STAFF ECONOMETRIC ELECTRICITY DEMAND FORECASTING SYSTEM

APRIL 1993

THE PUBLIC UTILITY COMMISSION OF TEXAS

TABLE OF CONTENTS

TECHNICAL APPENDIX
TO
PUCT STAFF ECONOMETRIC ELECTRICITY
DEMAND FORECASTING SYSTEM

CHAPTER ONE

PUCT STAFF FORECASTING MODELS

OVERVIEW

Staff has used simultaneous equation econometric models to produce electricity sales projections for each of the larger generating electric utilities in Texas. Each forecasting model contains a set of equations representing the relationships among a utility's costs, prices and sales, and how economic demographic, and climatological factors affect electricity sales.

Each of the forecasting models contains four submodels, which interact to produce forecasts of sales, prices, fuel costs, and numbers of customers:

1. The Electricity Sales Submodel;
2. The Electricity Price Submodel;
3. The Utility Cost Submodel; and
4. The Customer Submodel.

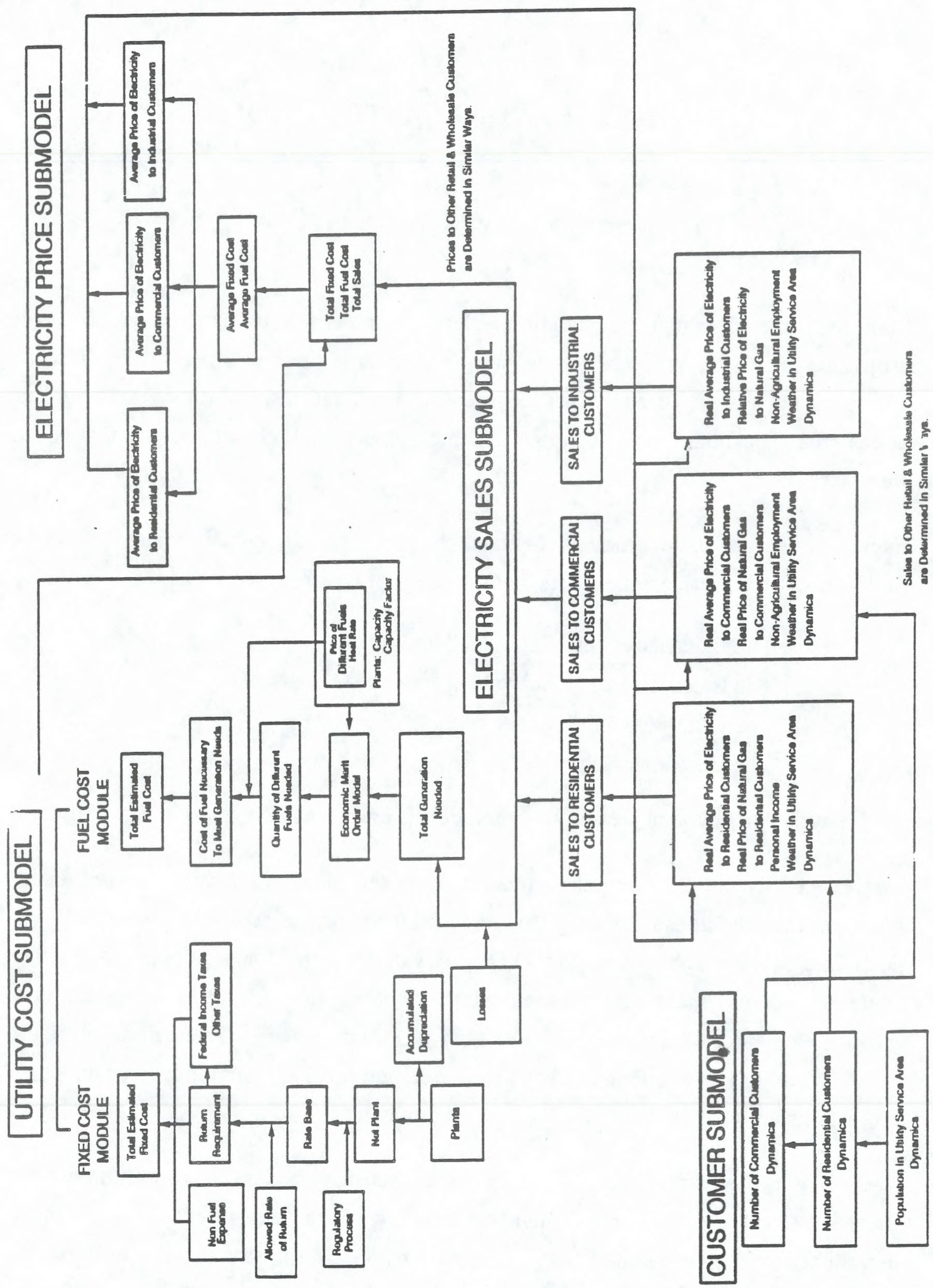
The relationship between these four submodels is graphically depicted in Figure 1.1.

The Electricity Sales Submodel consists of a set of statistically estimated equations describing the relationship among electricity sales to various customer classes and a set of economic, demographic, and climatological variables--including population, number of customers, employment, real personal income, cooling degree-days, heating degree-days, the price of natural gas, interest rates, and electricity prices. Projections of electricity prices (average) are obtained from the Electricity Prices Submodel, while customer projections are provided by the Customer Submodel.

The average electricity prices faced by various customer classes are determined by the Electricity Prices Submodel. Within this submodel, electricity prices are premised to be determined primarily by the utility's current average fuel costs, and the utility's average

ECONOMETRIC FORECASTING SYSTEM

FIGURE 1.1



fixed costs over a historical period. Here, fixed costs are treated as a catch-all for any significant utility costs that are not incorporated elsewhere within the submodels. These costs include depreciation expense, return on ratebase, nuclear decommissioning costs (where appropriate), taxes, and operations and maintenance (O&M) expense. Most of these costs are determined by the utility's assets or ratebase, and are "fixed" in the sense that they do not fluctuate with generation or sales levels. A major exception is O&M which has a variable component. Each utility's O&M projections, as presented in their forecast filings, are incorporated into the staff's fixed cost calculations for the Utility Cost Submodel.

The Utility Cost Submodel has two distinct components: a fuel cost model and a fixed cost model. The utility's fuel expenses are simulated using a simple "economic merit order" model, based on the premise that a utility satisfies the demand for electricity at any given point in time with the generating units having the lowest fuel costs. Generating capacity by fuel type, average fuel prices, heat rates, capacity factors, loss factors, and electricity sales are inputs to the fuel model. Sales estimates are obtained from the Electricity Sales Submodel.

Forecasts of a utility's asset base are based on current capacity expansion plans and construction cost estimates, among other factors. Debt service coverage is the primary determinant of fixed costs for cooperatives and publicly-owned utilities.

A utility's customers are projected based on anticipated population growth, as well as historical customer growth patterns. As in the other three submodels, statistical techniques are extensively relied upon in the Customer Submodel.

Each of the statistically determined relationships in each submodel (except the Customer Submodel) are estimated using the two-stage-least-squares estimation procedure to reduce simultaneous equation bias. Once each coefficient has been estimated, all the submodels (except the Customer Submodel) are solved simultaneously through an iterative procedure to yield a projection of electricity sales by customer class for a given utility.

The Hourly Electric Load Model (HELM) converts the projections of electricity sales into peak demand forecasts. The following subsections will describe the structure of each of these submodels in greater detail.

ELECTRICITY SALES SUBMODEL

The Electricity Sales Submodel (Figure 1.2) projects energy sales by customer class based on a set of economic, demographic, and climatological factors and the outputs from the Customer Submodel and the Electricity Price Submodel. Because the determinants of electricity consumption differ for various customer groups, electricity sales to different customer classes are modeled separately. As many as five different customer groups are treated independently in this submodel:

1. Residential
2. Commercial
3. Industrial
4. Other Retail
5. Wholesale

The Electricity Sales Submodels for each of the utilities under study are tailored to some extent to account for the unique record-keeping practices and customer mix of a particular utility.

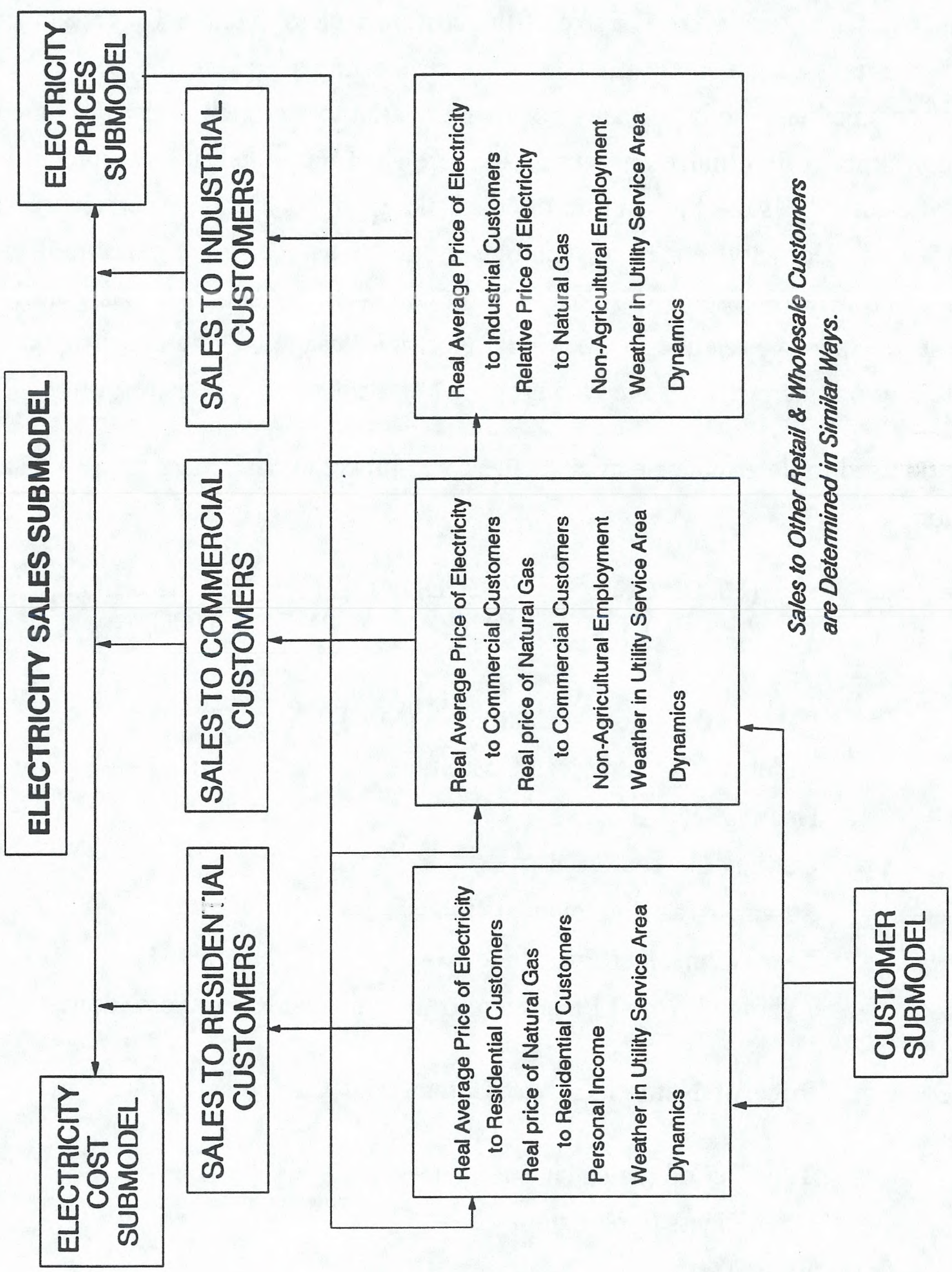
Equation specification and variable selection are based on a number of criteria, including compatibility with economic theory and previous studies, statistical results, data availability, and simulation behavior. The equation used to determine sales to residential ratepayers typically takes the following specification:

$$RS_t = b_0 + b_1*(HDD_t*RC_t) + b_2*(CDD_t*RC_t) + b_3*(PI_t/CPI_t)$$
$$+ b_4*[(RAP_t / CPI_t)*RC_t] + b_5*[(PNGR_{t-4} / CPI_{t-4})*RC_t] + e_t$$

where:

RS	=	Sales to Residential Customers (MWH)
RC	=	Number of Residential Customers
HDD	=	Heating Degree-Days
CDD	=	Cooling Degree-Days
PI	=	Nominal Personal Income (billions of dollars)
CPI	=	Texas Consumer Price Index
RAP	=	Average Price of Electricity to Residential Ratepayers (dollars per KWH)
PNGR	=	Price of Natural Gas to Residential Customers (dollars per MCF)

FIGURE 1.2


ELECTRICITY SALES SUBMODEL
ELECTRICITY PRICES SUBMODEL
ELECTRICITY COST SUBMODEL
SALES TO RESIDENTIAL CUSTOMERS
SALES TO COMMERCIAL CUSTOMERS
SALES TO INDUSTRIAL CUSTOMERS
Real Average Price of Electricity to Residential Customers
Real price of Natural Gas to Residential Customers
Personal Income
Weather in Utility Service Area
Dynamics
Real Average Price of Electricity to Commercial Customers
Real price of Natural Gas to Commercial Customers
Non-Agricultural Employment
Weather in Utility Service Area
Dynamics
Real Average Price of Electricity to Industrial Customers
Relative Price of Electricity to Natural Gas
Non-Agricultural Employment
Weather in Utility Service Area
Dynamics
CUSTOMER SUBMODEL
Sales to Other Retail & Wholesale Customers are Determined in Similar Ways.

t	=	Time period (calendar quarter)
$b_0 \ldots b_5$	=	Coefficients to be Estimated
e_t	=	Error Term

Most of the variables on the right side of the equation are multiplied by the number of residential customers to acknowledge that the energy impact of each of the demand determinants varies in relation to the size of the customer class. Heating degree-days and cooling degree-days variables are used to measure the impact of weather on electricity sales. Real personal income is normally positively related to electricity sales. As incomes increase, consumers often utilize and purchase more electricity-intensive equipment. The real price of electricity is used to capture price elasticity effects in the model. Increases in the real price of electricity tend to discourage usage. The real price of natural gas to residential customers represents the cost of alternative energy sources. As natural gas becomes more expensive relative to electricity, electricity usage may be encouraged. The four quarter lag on this variable acknowledges the long-run nature of this response.

The equation used to determine electricity sales to commercial customers follows a similar specification:

$$CS_t = b_0 + b_1*(HDD_t*CC_t) + b_2*(CDD_t*CC_t) + b_3*(EMPLOY_t) + b_4*[(CAP_t / CPI_t)*CC_t] + b_5*[(CAP_{t-4} / PNGC_{t-4})*CC_t] + e_t$$

where:

CS	=	Sales to Commercial Customers (MWH)
CC	=	Number of Commercial Customers
HDD	=	Heating Degree-Days
CDD	=	Cooling Degree-Days
EMPLOY	=	Service Area Employment (thousands)
CPI	=	Texas Consumer Price Index
CAP	=	Average Price of Electricity to Commercial Ratepayers (dollars per KWH)
PNGC	=	Price of Natural Gas to Commercial Customers (dollars per MCF)
t	=	Time Period (calendar quarter)
$b_0 \ldots b_5$	=	Coefficients to be Estimated
e_t	=	Error Term

Specification of the equation used to determine sales to industrial customers varies among models depending on each utility's industrial mix and other factors. The following specification is typical:

$$IS_t = b_0 + b_1*(CDD_t) + b_2*(IAP_t/CPI_t) + b_3*(EMPLOY_t) + b_4*(IAP_{t-4} / PNGI_{t-4}) + e_t$$

where:

IS	=	Sales of Electricity to Industrial Customers (MWH)
CDD	=	Cooling Degree-Days
CPI	=	Texas Consumer Price Index
EMPLOY	=	Service Area Employment (thousands)
IAP	=	Average Electricity Price to Industrial Ratepayers (dollars per KWH)
PNGI	=	Price of Natural Gas to Industrial Customers (dollars per MCF)
t	=	Time Period (calendar quarter)
$b_0 \ldots b_4$	=	Coefficients to be Estimated
e_t	=	Error Term

Other retail sales are primarily electricity sales for street and highway lighting or municipal purposes. Variables such as population, cooling degree-days, heating degree-days, electricity prices, and natural gas prices are used in their determination. Sales to wholesale customers are modeled using a similar set of explanatory variables.

ELECTRICITY PRICES SUBMODEL

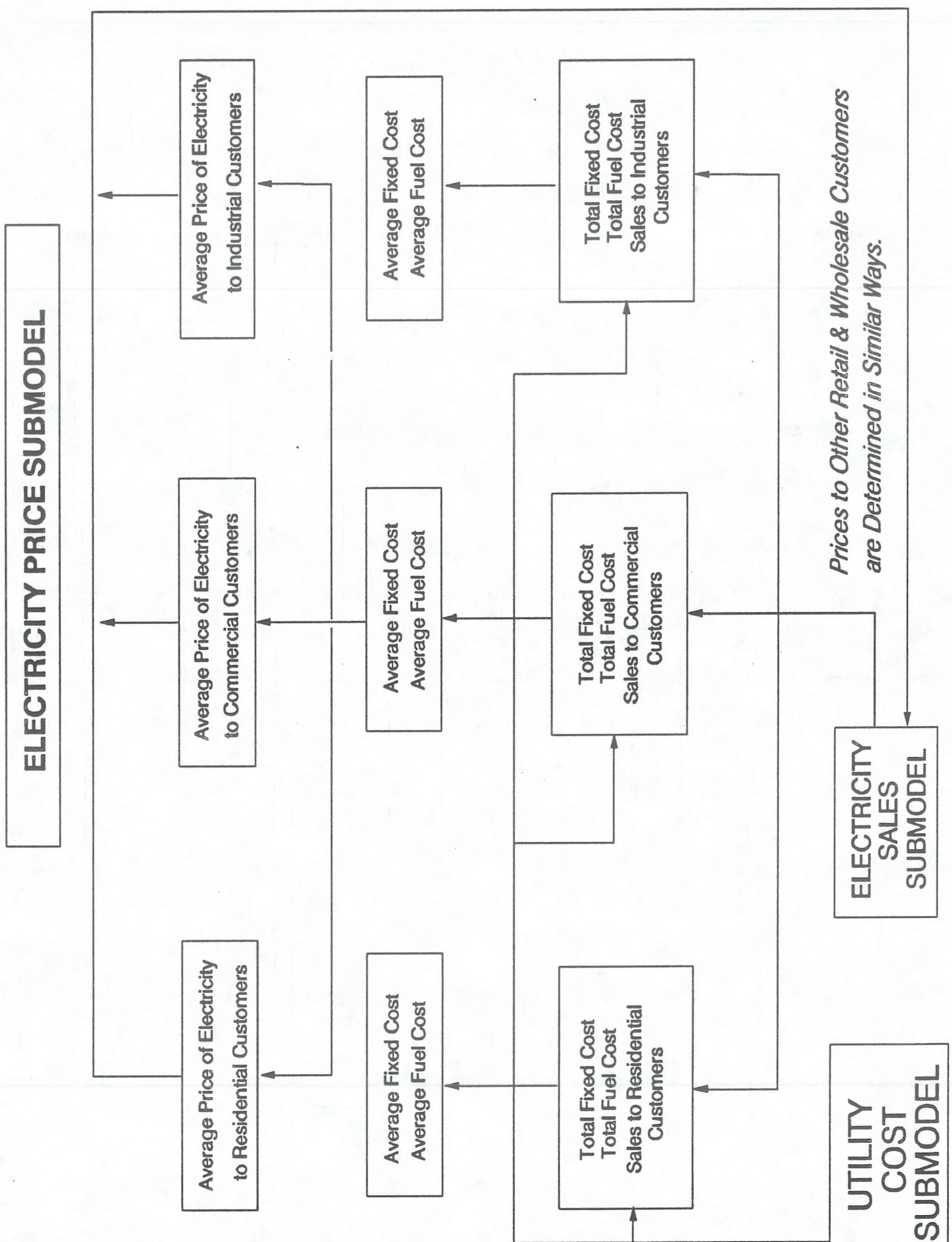
The main purpose of this submodel (Figure 1.3) is to provide average electricity price projections to the Electricity Sales Submodel. Average electricity prices are here defined as the revenue collected from a particular class divided by the units of electricity sold to that class in a given quarter. Separate equations are used to model the average prices faced by each class of customers. Each of the price equations takes the following general form:

$$AP_t = b_0 + b_1*(AFIXED_t) + b_2*(AFUEL_t) + e_t$$

where:

AP_t	=	Average Price of Electricity to a Particular Customer Class

FIGURE 1.3


ELECTRICITY PRICE SUBMODEL
Average Price of Electricity to Industrial Customers
Average Price of Electricity to Commercial Customers
Average Price of Electricity to Residential Customers
Average Fixed Cost
Average Fuel Cost
Average Fixed Cost
Average Fuel Cost
Average Fixed Cost
Average Fuel Cost
Total Fixed Cost
Total Fuel Cost
Sales to Industrial Customers
Total Fixed Cost
Total Fuel Cost
Sales to Commercial Customers
Total Fixed Cost
Total Fuel Cost
Sales to Residential Customers
Prices to Other Retail & Wholesale Customers are Determined in Similar Ways.
ELECTRICITY SALES SUBMODEL
UTILITY COST SUBMODEL

$AFIXED_t$	=	Four-Quarter Moving Average of Fixed Costs Divided by the Four-Quarter Moving Average of Total Sales (dollars per KWH)
$AFUEL_t$	=	Average Fuel Cost (Total Fuel Expense divided by Total Sales (dollars per KWH)
t	=	Time Period (calendar quarter)
$b_0 \ldots b_3$	=	Coefficients to be Estimated
e_t	=	Error Term

Under this specification, the average price of electricity to a particular customer class is primarily determined by the utility's average fixed costs and average fuel costs. Rates are assumed to be based partially on a utility's fixed costs divided by total sales over a historical "test year" period.

UTILITY COST SUBMODEL

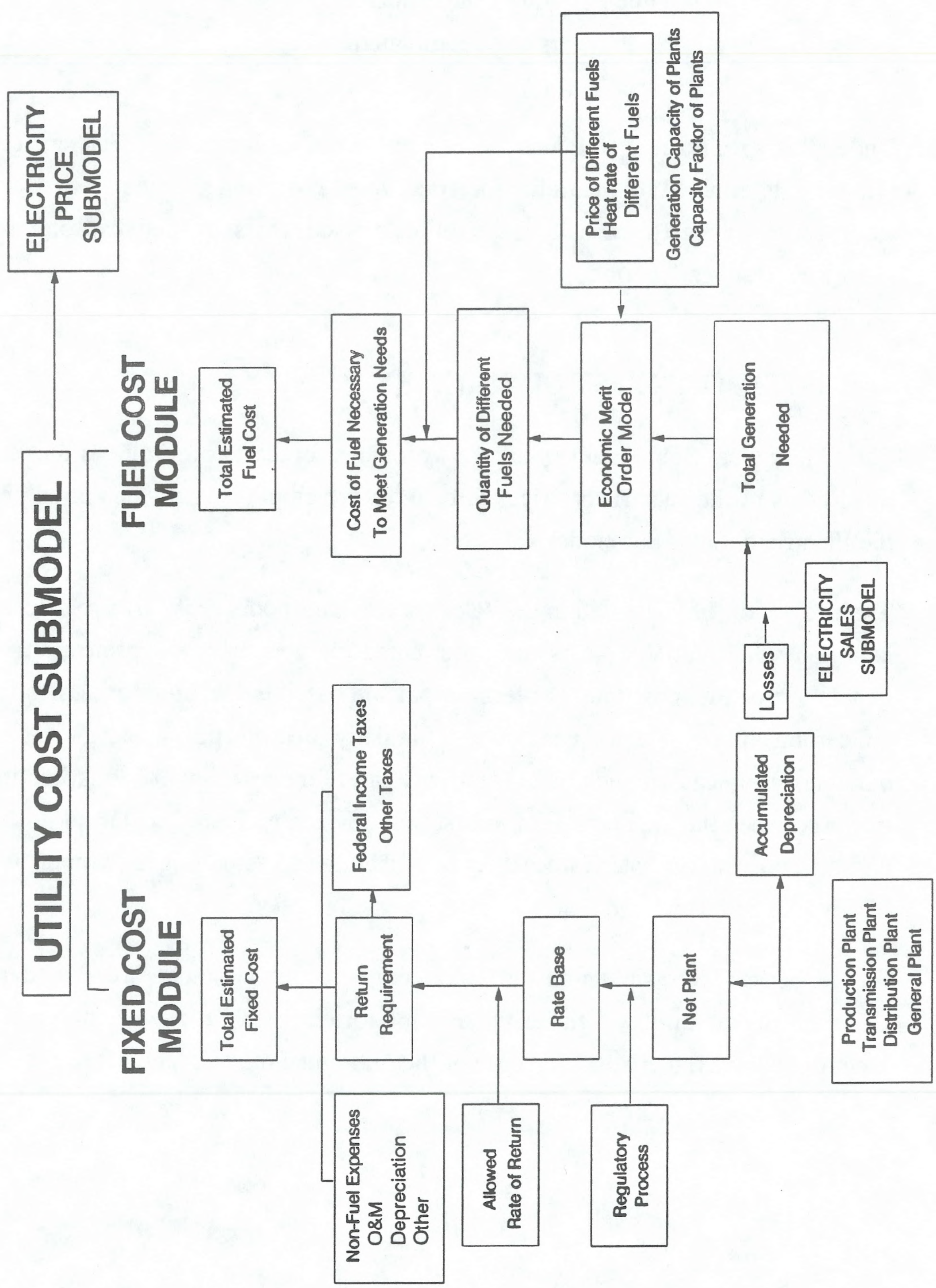
The Utility Cost Submodel (Figure 1.4) provides forecasts of a utility's fuel expenses and fixed costs to the Electricity Prices Submodel, which in turn provides price projections to the Electricity Sales Submodel.

The projection of costs within the sales forecasting model seeks to avoid forecasting bias common when variable costs are determined exogenously. A projection of a utility's generation or fuel cost must, at least in part be based either on a forecast or assumptions concerning future sales or generation. Similarly, a projection of cost, fed through price variables, is at least implicit in an electricity sales forecast. Should a marked inconsistency occur between the implicit sales forecast, upon which projected costs and prices are based, and the econometric sales forecasts, which use the projected prices as inputs, a forecasting bias would be introduced.

Fuel expenses were simulated through a simple economic merit order model. Based on the premise that a utility satisfies the demand for electricity at any given time with the units having the lowest fuel cost, the logic of this submodel may be represented as:

ECONOMETRIC FORECASTING SYSTEM

FIGURE 1.4



FUEL COST SUBMODEL

UC_{it}	=	(Fuel $Price_{it}$)	* (Heat $Rate_{it}$)
Unit Cost of Production Fuel Type i at Time t ($/KWH)		$/MMBTU Fuel Type i at Time t	MMBTU/KWH Fuel Type i at Time t

where:

i = 1,...,7

1 = Purchase Power
2 = Hydroelectric
3 = Lignite
4 = Nuclear
5 = Coal
6 = Natural Gas
7 = Cogeneration

$$\underset{KWH_{it}}{\text{Minimize}}\ TFUELC_t = \sum_i (UC_{it} \cdot KWH_{it})$$

s.t. (1) Generation $Required_t$ (KWH) = ($Sales_t$ + $Losses_t$ + Company Use_t)

(2) $KWH_{it} \leq (CAPF_{it})(CAP_{it})$ (2,190 hours)

(3) $\sum_i KWH_{it} \geq$ Generation $Requirements_t$ (KWH)

where:

KWH_{it}	=	Generation Requirement from Fuel Type i at Time t
TFUELC	=	Total Fuel Cost
SALES	=	From Electricity Sales Submodel
CAPF	=	Capacity Factor
CAP	=	Capacity
2,190	=	Hours in Calendar Quarter
i	=	Fuel Type
t	=	Time Period (calendar quarter)

NOTE: The actual programming statements in the computer code are somewhat different than the statements given above; however, the logic is similar.

Generation requirements by fuel type are determined by total generation requirements, capacities of different plants, and capacity factors. Total generation requirements are estimated by adjusting total sales for line loss and company use.

In the models at each time period (calendar quarter), generation requirements are met by output from the lowest cost unit to the highest cost unit. By explicitly incorporating capacity considerations, fuel cost savings resulting from new baseload units coming on-line can be reflected in the model. Data Resources Inc.'s (DRI) Energy Model includes a very similar means of calculating fuel costs of generating electricity on a regional level. (U.S. Energy Model Documentation, Data Resources, Inc., 1984)

The total cost for each fuel type is calculated by multiplying generation requirements associated with each fuel type by heat rates and average fuel costs. In cases where a utility does not have and does not intend to construct capacity of a given type, the equations associated with that capacity type are excluded from the submodel.

The cost of the fuel necessary to meet generation requirements is the sum of the costs associated with each fuel type:

$$TF = NGC + COC + LIGC + NUC$$

where:

TF	=	Total Cost of Fuel Necessary to Meet Generation Needs
NGC	=	Total Natural Gas Fuel Cost
COC	=	Total Coal Fuel Costs
LIGC	=	Total Lignite Fuel Costs
NUC	=	Total Nuclear Fuel Costs

However, the actual available data concerning each utility's fuel costs are based on fuel <u>purchases</u>. A "mismatch" commonly occurs between each utility's fuels purchased and fuels actually used in any given time period. This discrepancy may be further increased by power exchanges and purchases among utilities, the assumption of choice of a constant ratio between sales and generation requirements, and the inventory costing method. A simple stochastic equation was used to correct for this mismatch:

$$CFPt = b0 + b1\ TFt + e_t$$

where:

CFP	=	Cost of Fuels Purchased
TF	=	Total Cost of Fuel Necessary to Meet Generation Needs

t	=	Time Period (calendar quarter)
b_0, b_1	=	Coefficients to be Estimated
e_t	=	Error Term

Two models were used to determine utility fixed costs. For publicly-owned utilities, fixed costs are based on debt service coverage. Historic fixed costs are derived from annual reports. The quarterly amount of fixed charges is estimated by multiplying the expected debt service coverage ratio times the projected total debt service amount, then subtracting projected interest income. Since utility projections of debt service coverage sometimes move erratically, the fixed cost projections are smoothed in some cases.

Fixed costs for an investor-owned utility are defined as the sum of depreciation expense, return requirements, projected nuclear decommissioning cost, federal income tax, other revenue-related taxes, and O&M expense.

Quarterly historical data on total plant, accumulated depreciation, net plant, depreciation expense, and interest expense were obtained from Securities and Exchange Commission Forms 10Q and 10K. Some of these data were unavailable; interpolations were utilized in these situations. Allowed rate of return, weighted cost of debt factors, and ratebase amounts were taken from Final Orders issued by the Public Utility Commission of Texas (PUCT).

To forecast each of the fixed cost categories it is first necessary to project a utility's total plant. Total plant is the sum of four categories of assets:

$$TOTP = PP + TP + DP + GP$$

where:

TOTP	=	Total Plant in Service
PP	=	Production Plant in Service
TP	=	Transmission Plant in Service
DP	=	Distribution Plant in Service
GP	=	General Plant in Service

Future production plant in service is estimated by adding the estimated construction costs of various generating plant construction projects to this series at the expected on-line dates of the units. In some cases, production plant impacts are "smoothed" over time.

Future values of transmission plant, distribution plant, and general plant are projected using regression techniques. The following specification is used:

$$(P_{it}-P_{it-1}) / CI_{it} = b_1 [\ln(POP_t)-\ln(POP_{t-1})]+ e_t$$

where:

P_i	=	Plant
CI	=	Cost Index
POP	=	Service Area Population
t	=	Time Period
i	=	Plant Type (Transmission[1], or Distribution, General)
b_1	=	Coefficient to be Estimated
e_t	=	Error Term

Changes in plant-in-service are first calculated and deflated by the appropriate Handy-Whitman cost index. The resulting real changes in plant in service are then regressed on the change in the natural logarithm of service area population.

Once projections of total plant are developed, depreciation expense is calculated by multiplying Total Plant by a depreciation rate:

$$DE = dr * TOTP$$

where:

DE	=	Depreciation Expense
dr	=	Depreciation Rate (1975-1985)
TOTP	=	Total Plant in Service

Accumulated depreciation and net plant may then be calculated:

$$AD_t = AD_{t-1} + DE_t$$
$$NP_t = TOTP_t - AD_t$$

where:

AD	=	Accumulated Depreciation
DE	=	Depreciation Expense
NP	=	Net Plant
TOTP	=	Total Plant in Service

---

1 Many utilities reported the estimated costs of transmission line construction projects in response to Request 7.06 of the Load Forecast Filing. In these cases, the estimated transmission plant costs were incorporated into total plant in the same manner as future additions to production plant. Where this information was not available, the estimated econometric equation was used to predict future additions to transmission plant.

t = Time Period

In the projected period, ratebase is composed of a component estimated from net plant. The net plant component is estimated by dividing the projected net plant by the historic average ratio of net plant to ratebase. This factor implicitly includes other components of allowed ratebase as a function of net plant. In general it its assumed that no CWIP will be allowed in the ratebase for future construction projects.

Symbolically, ratebase is estimated as:

$$RB = (NP / NPRBF)$$

where:

RB = Ratebase

NP = Net Plant

NPRBF = Nondepreciable Ratebase Factor

Federal income taxes permitted by the regulatory authority are determined by the taxable component of return, multiplied by the tax factor. To calculate the taxable component of return, interest expense is calculated and subtracted from the return requirement. These calculations are summarized as follows:

$$IE = w * RB$$

$$RR = ror * RB$$

$$FIT = tf * (RR - IE)$$

where:

IE = Interest Expense

RB = Ratebase

RR = Return Requirement

FIT = Federal Income Tax

w = Weighted Cost of Debt

ror = Regulatory Authority's Allowed Rate of Return

tf = Federal Income Tax Factor

The rate of return and weighted cost of debt from actual rate cases are used for the historical period. The allowed weighted cost of debt and rate of return from each utility's most recent rate case are assumed constant in the forecast period.

Initially, other revenue-related taxes are calculated at the rate allowed in each utility's most recent rate case. The resulting fixed cost revenue requirement is then compared with the revenue requirement from the most recent rate case, less fuel and purchased power. If the difference is substantial, other revenue-related taxes are used as a "calibration variable" to bring the model's forecast (as of the period of the last rate case) into line with allowed fixed costs.

Total fixed costs are then calculated as the sum of depreciation expense, return requirement, O&M expense, federal income tax, nuclear decommissioning costs, and other revenue-related taxes.

$$FC = DE + RR + FIT + DC + ORRT$$

where:

FC	=	Fixed Costs
DE	=	Depreciation Expense
RR	=	Return Requirement
FIT	=	Federal Income Tax
DC	=	Nuclear Decommissioning Costs
ORRT	=	Other Revenue-Related Taxes

There is an additional cost that is added to the fixed cost described above. There is a capacity charge associated with purchase power. If applicable, these charges are added to FC yielding total fixed costs.

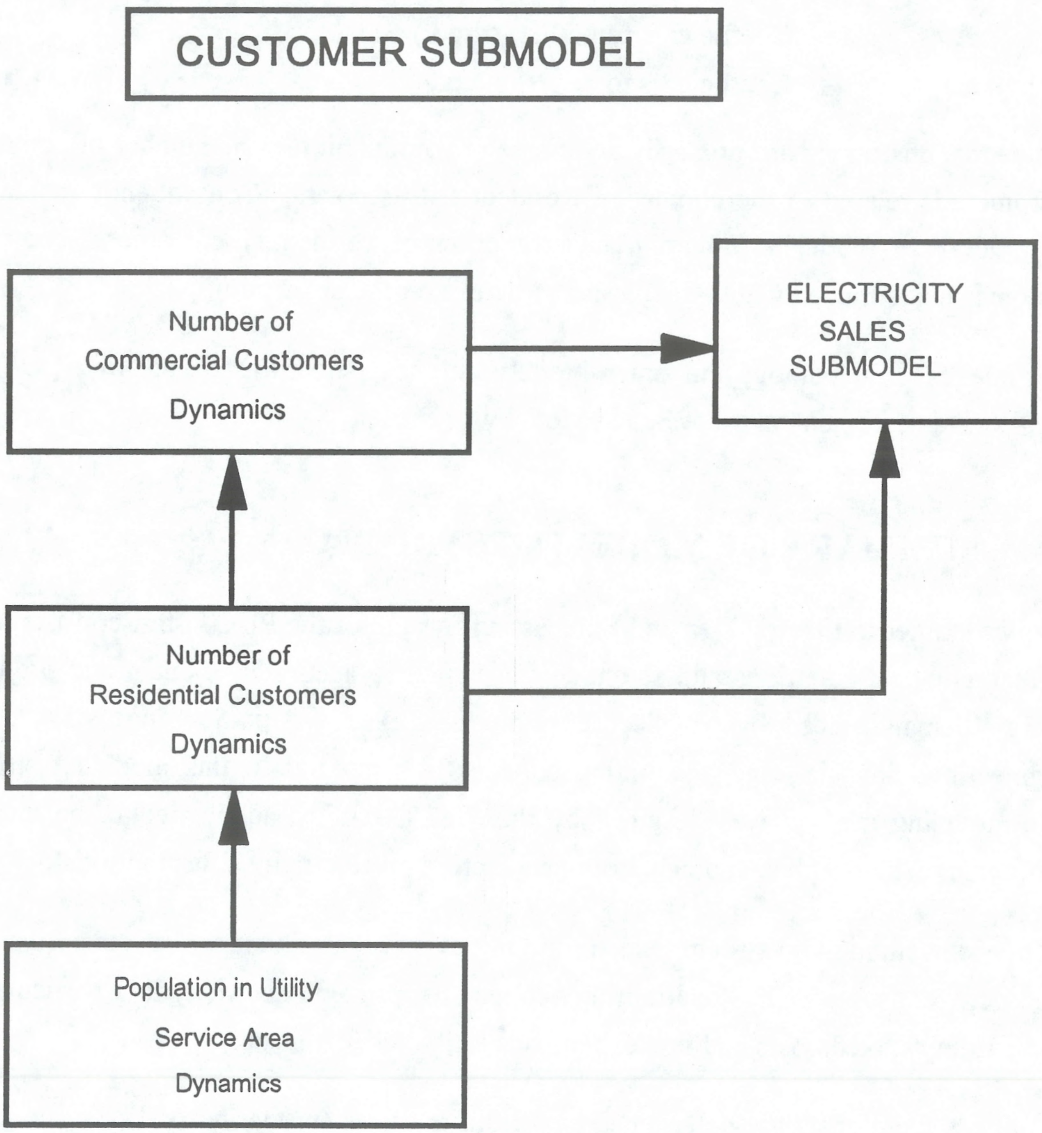
For those utilities whose service area extends beyond Texas, the fixed costs were first calculated on a total system basis. A Texas allocator was then applied to obtain the portion of fixed costs associated with the Texas system.

CUSTOMER SUBMODEL

The Electricity Sales Submodel (Figure 1.5) relies, in part, upon a projection of number of residential and commercial customers in the development of an electricity sales projection. These customer projections are provided by the Customer Submodel. These models are run on a personal computer using a multiple regression program.

Each Customer Submodel contains two statistically estimated equations: one to determine number of residential customers and one for commercial customers. The exact specification of these equations vary among models in order to satisfy statistical criteria. An example specification is:

FIGURE 1.5


CUSTOMER SUBMODEL
Number of Commercial Customers Dynamics
ELECTRICITY SALES SUBMODEL
Number of Residential Customers Dynamics
Population in Utility Service Area Dynamics

$RC_t = a_0 + a_1*(POP_t)$ + (AR Process of Error Term)

$CC_t = b_0 + b_1*(RC_t) + b_2*(CC_{t-4})$ + (AR Process of Error Term)

where:

RC	=	Number of Residential Customers
CC	=	Number of Commercial Customers
POP	=	Service Area Population
t	=	Time Period (calendar quarter)
AR Process	=	Auto-Regressive Correction)
$a_0 ... a_1$	=	Coefficients to be Estimated
$b_0 ... b_2$	=	Coefficients to be Estimated

Residential customers are primarily determined by population. The number of commercial customers is related to the number of Residential Customers. Consequently, commercial customers are modeled primarily as a function of residential customers, commercial customer lagged, and an auto-regressive structure on the error term.

In some cases the above customer models did not perform satisfactorily. On those occasions a more general State Space Model was chosen

SUMMARY OF MODELING STRUCTURE

The Econometric Electric Demand Forecasting System of the PUCT staff consists of a set of mathematical equations and submodels designed to accurately explain and project the energy demand faced by an electric utility in Texas. A wide range of economic, engineering, financial, and accounting concepts are integral to this modeling structure. The modeling method was designed by the PUCT staff to acknowledge the impact of economic, demographic, and climatological factors on electricity consumption.

Within this modeling system, electricity prices have an influence on the quantity of electricity consumed. The relationship between the price of electricity to a particular class and a utility's fixed costs and fuel expenses is estimated statistically.

A utility's fixed costs are determined by a utility's assets (primarily total plant in service), allowed rates of return, depreciation rates, tax factors, weighted cost of debt, and a set of accounting and economic relationships.

Fuel costs are calculated through "economic merit order" logic, based on the assumption that a utility meets a given load level with the combination of generating units having the lowest fuel cost. Fuel prices, capacity factors, heat rates, capacity by fuel type, loss factors, and total sales are among the inputs into this calculation.

The numbers of residential and commercial customers, two other important determinants of energy sales, are projected on the basis of population and lagged number of customers.

Each of the four submodels in this system interact to produce a projection of electricity sales for a given utility. Specific models estimated for the 13 major utilities in Texas are presented in Chapter Four of this Appendix. The following chapter will discuss the database used in this forecasting system.

CHAPTER TWO

DATABASE DEVELOPMENT

INTRODUCTION

Three of the most imposing problems typically facing electric demand forecasting efforts are:

1. Matching county, SMSA, or state-level data to a utility's geographical service area;

2. Transforming data of dissimilar frequencies (e.g., annual, quarterly, and monthly) to a comparable frequency; and

3. Developing reasonable projections of the factors affecting future electricity demand.

Electric utility service areas rarely correspond to political boundaries. Thus, it is often necessary to proportion and aggregate county-level data in order to derive some estimate of a service area's economic-demographic profile. The next section of this chapter describes how the state is divided into "utility planning regions" for the purposes of this study. Each region is designed to roughly correspond to the service area of a generating electric utility and the nongenerating distribution utilities to which it normally sells power. These regions provide a basis for estimating service area population, personal income, and employment and for developing an economic/demographic profile of the utility's operating environment.

This chapter also lists the sources of the historical data used in this study, as well as the transformations used to develop quarterly time-series. Most of the utility operating data are obtained from the utilities' responses to data requests by the PUCT. Historical economic and demographic data are obtained from a number of state and federal government agencies, as well as Data Resources, Inc.

Finally, to forecast the demand for electricity using an econometric approach, it is necessary to obtain projections or make reasonable assumptions regarding the future of the factors assumed to influence electricity demand. The final section of this chapter discusses these exogenous variable projections.

METHODOLOGY OF AGGREGATING COUNTY LEVEL ECONOMIC DEMOGRAPHIC DATA

County-level economic and demographic data has been apportioned to "utility planning regions". Each utility planning region was designed to correspond to the service area of a generating utility and the service areas of any nongenerating distribution utility to which the generator normally sells power. A spring 1985 staff study was the basis for the utility planning region delineation used here.

The basic methodology for deriving the service area divisions is fairly straightforward, but the actual application of these methods is very tedious and time consuming. The first step in the process is to develop a set of maps to illustrate what portion of each county in Texas is served by a particular utility. The initial maps, which are provided by the PUCT engineering staff, indicate which regions are served by each utility, including cooperatives. Then the determination is made as to which generating utilities supply power to the nongenerating utilities and the electric cooperatives through reference to the **Directory of Electric Utilities**, (McGraw-Hill, 1983-1984 edition). The 17 cooperatives that purchase electricity from more than one utility were then contacted by telephone to determine the portion of each county in their service area that is served by a specific generating utility. In most cases, this information is easily derived based on the cooperatives' transmission network. The original maps are then altered to pictorially represent the "utility planning regions" of the major generating utilities in the state. Once the physical determination of which utilities supplied power to specific regions of each county is made, the task is then to indicate the proportion of the population in each county that is contained in a given service area.

The counties are separated into subdivisions defined by the **1980 Census of Housing: General Housing Characteristics, Part 45 Texas**, and these subdivisions were translated to the maps. The census provides housing and population information for each of the subdivisions, including single- and multiple-dwelling units. Using local highway maps and the population of cities within each subdivision as a reference, the percentage of each subdivision that is served by a particular utility is determined.

SOURCES OF HISTORICAL DATA

The data used in this study were obtained from a variety of sources. This subsection reviews data sources and concepts.

Weather Data

Source: U.S. Department of Commerce, National Oceanic and Atmospheric Administration.

Series: Heating Degree Days and Cooling Degree Days

Weather Stations:

Texas:	Abilene	Amarillo	Austin
	Brownsville	Corpus Christi	Dallas
	Del Rio	El Paso	Galveston
	Houston	Lubbock	Midland
	Port Arthur	San Angelo	San Antonio
	Victoria	Waco	Wichita Falls
Louisiana:	Baton Rouge	Lake Charles	Shreveport
Arkansas:	Fort Smith		

Population

Source: Annual county-level data from DRI/McGraw-Hill, the U.S. Bureau of Economic Analysis, and the U.S. Department of Commerce, Bureau of the Census.

Series: Total Population for Texas Counties and Parts of Oklahoma, New Mexico, Louisiana, Arkansas, and Kansas. (Thousands)

Aggregation to Utility Planning Region-Level:
See Previous Section.

Transformation to Quarterly:
Linear interpolation.

Personal Income

Source: Annual county-level data from DRI/McGraw-Hill and the U.S. Department of Commerce, Bureau of Economic Analysis.

Series: Total Personal Income by Place of Residence for all counties in Texas and parts of Oklahoma, New Mexico, Louisiana, Arkansas, and Kansas. (Billions of current dollars.)

Aggregation to Utility Planning Region-Level:
See Previous Section.

Transformation to Quarterly:
Linear Interpolation.

Employment

Source: Annual county-level data from DRI/McGraw-Hill, Oklahoma Employment Security Commission, New Mexico Department of Labor, Louisiana Department of Labor, Arkansas Employment Security Division, and the Kansas Employment Security Division.

Series: Total Non-agricultural Employment Wage and Salary Employment (employment excluding proprietors). (Thousands)

Aggregation to Utility Planning Region-Level:
See Previous Section

Transformation to Quarterly:
Linear Interpolation.

Consumer Price Index

Source: Data Resources, Inc.

Series: Texas CPI.

Price of Natural Gas to Residential, Commercial, and Industrial Consumers

Source: Texas Railroad Commission.

Series: Delivered gas prices to Residential, Commercial, and Industrial Customers--Texas. (Dollars per MCF)

Fuel Prices

Source: Calculated from Request 8 of the utilities' latest Load and Capacity Resource Forecast filing with the PUCT.

Series: Average fuel cost by utility by fuel type (natural gas, fuel oil, bituminous coal, sub-bituminous coal, lignite, etc.). (Dollars per MMBTU.)

Total Fuel and Purchased Power Expense

Source: Request 8 of the utilities' latest Load and Capacity Resource Forecast filing with the PUCT. (Thousands of dollars)

Capacity Data

Source: Requests 1, 7, and 8 of the utilities' latest Load and Capacity Resource Forecast filing with the PUCT.

Series: Utility-specific MW capacity by fuel type.

Financial Data

Source: Forms 10Q and 10K to the Securities and Exchange Commission. Final Orders of the PUCT.

Series: Depreciation Expense
Plant in Service
Accumulated Depreciation
Allowed Rate of Return
Weighted Cost of Debt

Operating Data

Source: Request 6.01 of the utilities' latest Load and Capacity Resource Forecast filing with the PUCT. Additional data were obtained from FERC Forms 1, the DOE's statistics of Publicly-Owned Utilities and statistics of Privately-Owned Utilities, and Annual Reports to Stockholders.

Series: The data received varied among utilities. Generally the information included total electric expenses (or operating expenses) and sales and revenues by rate class (residential, commercial, industrial, and other).

Electricity Sales, Revenue, and Customer Data

Source: Request 2 of the utilities' latest Load and Capacity Resource Forecast filing with the PUCT.

Series: Monthly data on sales, revenue, and customers by revenue class.

SOURCES OF PROJECTIONS FOR EXOGENOUS VARIABLES

A key step in developing the capability to project future electricity demand is deriving reasonable forecasts of the factors believed to influence the demand for electricity. This subsection describes the forecasts of exogenous variables used in this study.

Weather Data "Normal" weather was calculated by simply averaging quarterly historical values. "Normal heating degree days" and "normal cooling degree days" are based on 18-year averages.

Population, Employment, and Personal Income The projections of these service area economic data are generated by the PUCT Economic Analysis Section based on DRI/McGraw-Hill forecasts. Table 2.1 provides a summary of the growth rates (in percentage terms) for these variables between 1990 and 2001.

Consumer Price Index The projected Texas CPI is based on the DRI/McGraw-Hill Fall 1991 Forecast. The average inflation rate projected over the 1990-2001 period is 4.2 percent.

Price of Natural Gas to Residential, Commercial, and Industrial Consumers The price projections for natural gas are provided by the Fuel Section of the Electric Division of the PUCT. The price of natural gas is modeled as a function of the spot price of natural gas. Natural gas prices are forecasted through 2006 for each of the thirteen major utilities discussed throughout this report. The average compound growth rates for the 10-year forecast period for residential, commercial, and industrial customers are 3.6, 3.7, and 3.9 percent respectively.

Fuel Prices Projected fuel prices by fuel type for each utility serving Texas are calculated by the Fuel Section of the Electric Division of the PUCT. These long-term projections take into account projected spot market price, existing contracts, and a number of other factors. Projected fuel costs are found in Volume I, Chapter Two of this report.

Capacity Expansion Data Capacity expansion data are based the staff's latest resource plan and augmented with information taken from the Load and Capacity Resource Forecast filed by the state's generating electric utilities in December 1991. The data reflect staff-proposed modifications to the utility-proposed capacity expansion plans as described in Volume I, Chapter Six.

Financial Data Financial data are projected via the fixed cost model described in Chapter Two of this volume. The capacity expansion data drives these projections. Some of the data is provided in Request 7.02 of the utilities' latest Load and Capacity Resource Forecast filing with the PUCT.

Operating Data Operation and maintenance expense projections are obtained from Request 6.01 of the utilities' latest Load and Capacity Resource Forecast filing with the PUCT.

TABLE 2.1

STAFF-PROJECTED GROWTH RATES
SERVICE AREA ECONOMIC/DEMOGRAPHIC VARIABLES
1990/2001 (Percent)

Utility Service Area	Total Population	Non-Agricultural Employment	Nominal Personal Income	Real Personal Income
TU Electric	1.06	1.54	6.35	2.12
HL&P	1.45	1.90	6.82	2.57
GSU-TX	1.00	1.40	6.22	1.99
CPL	1.29	1.95	6.59	2.35
CPS	1.50	1.65	6.20	2.15
SPS-TX	1.21	1.65	6.37	2.13
SWEPCO-TX	1.06	1.52	6.27	2.03
LCRA	1.11	1.84	6.74	2.49
COA	1.42	1.94	6.79	2.54
WTU	1.39	1.78	6.43	2.19
EPE-TX	1.37	1.80	6.76	2.50
TNP	1.11	1.75	6.32	2.09
BEPC	1.11	1.87	6.57	2.33
TEXAS				
LEVEL (1990)	17,207,100	7,030,742	283,385*	295,266*
LEVEL (2001)	19,642,349	8,457,528	566,237*	377,265*
GROWTH RATE(%)	1.21	1.69	6.49	2.25
NON-TEXAS				
EPE-NTX	1.37	1.80	6.76	2.51
GSU-NTX	0.92	1.39	6.22	1.99
SWEPCO-NTX	0.79	1.34	6.02	1.79
SPS-NTX	1.21	1.65	6.37	2.13

* - Millions of dollars.

Sources:

DRI/McGraw Hill: Regional Information Service-Southern Focus; third quarter, 1991
Texas Economic Forecast: M. Ray Perryman, Ph.D.; May, 1992
U.S. Department of Commerce, Bureau of the Census; County Population Estimates, April 1990, January 1988, August, September, December, 1987
U.S. Bureau of Economic Analysis; Local Area Personal Income, Southeast Region 1982-1989
Oklahoma Employment Security Commission; County Employment And Wage Data; November 1989
Arkansas Employment Security Commission; Labor Force Statistics; May 1989; August 1983
New Mexico Department of Labor; Non-Agricultural Wage And Salary Employment; March 1990; May 1981
Louisiana Department of Labor; Employment And Wages; October 1987; November 1986; October 1983; November 1980; August 1977
Kansas Department of Labor; Covered Employment Data; August 1990

CHAPTER THREE

ESTIMATION AND FORECASTING PROCEDURES

SALES MODEL ESTIMATION PROCEDURE

The 1992 Long-Term Peak Demand and Capacity Resource Forecast for Texas, like the 1990 report, is the incorporation of the data base and model development in a PC environment using Time Series Processor (TSP). TSP, created in 1967 by Bronwyn H. Hall for Time Series International, provides regression, forecasting, and advanced econometric techniques on mainframe and smaller computer frameworks.

The appropriate choice of estimation technique for a simultaneous equation model is a frequent topic of debate. From a purely theoretical perspective, two-stage-least-squares, three-stage-least-squares, or full-information-maximum-likelihood techniques are favored for their minimization of simultaneous equation bias. Practitioners often find ordinary least squares to be more robust, especially in small samples where full information estimators lose their desirable properties. Both ordinary least squares and two-stage-least-squares are applied to the models. Since the estimation results do not differ significantly with respect to the choice of estimator, the more theoretically appealing model, two-stage-least-squares (TSLS), is used in producing the final results.

With the TSLS method, exogenous variables are combined to act as a "best-choice" instrument. Thus, each endogenous variable is explained by the "best" instrumental variables through the simultaneous interaction of the entire system of equations. In most cases, all of the "important" predetermined (exogenous and lagged endogenous) variables involved in the stochastic equations are selected as instruments. In some of the larger models, dummies and other variables of lesser importance are excluded to enable the instrument set to satisfy the constraint that the number of instruments not exceed the number of observations.

A common problem encountered in dealing with time series (especially when some data are transformed) is the presence of autocorrelation. In the presence of autocorrelation, the estimated coefficients are not minimum variance and are not consistent. Therefore, the estimated coefficients will not be as precisely determined as they might be. As a result, a modified TSLS procedure is used when appropriate. This method uses the algorithm developed by Fair (1970) to correct for autocorrelation in simultaneous equation systems. Fair has determined that when performing instrumental variable estimation combined with a serial correlation correction, the lagged dependent and independent variables must be in the instrument list in order to obtain consistent estimates.

Simulation is performed using the Gauss-Seidel method for minimization. Gauss-Seidel method is a classical method for iterative solution of a set of linear equations, particularly those arising from least squares solutions, and is fundamentally a recursive loop through the equations.

CONVERSION TO PEAK DEMAND PROJECTIONS

The electricity sales projections produced by the Econometric Modeling System previously described are converted into forecasts of peak demand using the Hourly Electric Load Model (HELM). HELM, which was developed by ICF, Incorporated for EPRI, is a structural model which applies hourly load shapes to class (i.e., Residential, Commercial, Industrial) sales forecasts to obtain hourly demand projections. The hourly demands are then summed across classes and added to hourly losses to produce hourly demand for the entire system. Peak demand is then extracted from this system hourly demand forecast.

Generation requirements are also calculated in HELM by adding total system losses to the total sales projections. The system losses are obtained by applying loss factors to the class sales projections and then summing across the classes. Class loss factors used in this step are derived from the results of utility-sponsored loss studies presented in recent rate cases before the Commission or contained in the utility load forecast filings.

CHAPTER FOUR

MODEL ESTIMATION RESULTS

4-1 TEXAS UTILITIES ELECTRIC COMPANY

MODEL: TUEC

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCTUE	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRTUE	-	AVERAGE FUEL AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
COAPINS	-	INSTRUMENT FOR COAPTUE
COAPTUE	-	AVERAGE PRICE FOR COMMERCIAL AND "OTHER" CLASS:'000 OF $ PER MWH
COSTUE	-	COMMERCIAL AND "OTHER" SALES:MWH
GENRTUE	-	GENERATION REQUIREMENTS:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENT FROM PLANT D:MWH
GRPLNTE	-	GENERATION REQUIREMENT FROM PLANT E:MWH
GRPLNTF	-	GENERATION REQUIREMENT FROM PLANT F:MWH
GRPLNTG	-	GENERATION REQUIREMENT FROM PLANT G:MWH
GRPLNTH	-	ENERATION REQUIREMENT FROM PLANT H:MWH
GRPLNTI	-	GENERATION REQUIREMENT FROM PLANT I:MWH
GRPLNTJ	-	GENERATION REQUIREMENT FROM PLANT J:MWH
GRPLNTK	-	GENERATION REQUIREMENT FROM PLANT K:MWH
GRPLNTL	-	GENERATION REQUIREMENT FROM PLANT L:MWH
GRPLNTM	-	GENERATION REQUIREMENT FROM PLANT M:MWH
GRPLNTN	-	GENERATION REQUIREMENT FROM PLANT N:MWH
GRPLNTO	-	GENERATION REQUIREMENT FROM PLANT O:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCAHSED POWER FROM NON-UTILTY SOURCES
IAPTUE	-	INDUSTRIAL AVERAGE PRICE:'000 OF $ PER MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE

PLNTDC	-	CONDITIONAL VARIABLE
PLNTEC	-	CONDITIONAL VARIABLE
PLNTFC	-	CONDITIONAL VARIABLE
PLNTGC	-	CONDITIONAL VARIABLE
PLNTHC	-	CONDITIONAL VARIABLE
PLNTIC	-	CONDITIONAL VARIABLE
PLNTJC	-	CONDITIONAL VARIABLE
PLNTKC	-	CONDITIONAL VARIABLE
PLNTLC	-	CONDITIONAL VARIABLE
PLNTMC	-	CONDITIONAL VARIABLE
PLNTNC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RAPINST	-	INSTRUMENT FOR RAPTUE
RAPTUE	-	RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
RSTUE	-	RESIDENTIAL SALES:MWH
TSTUE	-	TOTAL SYSTEM SALES:MWH
VCETUE	-	TOTAL FUEL EXPENSE AND PURCHASE POWER EXPENSE ESTIMATE: 000'S OF DOLLARS
VCPLNTA	-	VARIABLE COST FOR PLANT A:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B:000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANT C:000'S OF $
VCPLNTD	-	VARIABLE COST FOR PLANT D:000'S OF $
VCPLNTE	-	VARIABLE COST FOR PLANT E:000'S OF $
VCPLNTF	-	VARIABLE COST FOR PLANT F:000'S OF $
VCPLNTG	-	VARIABLE COST FOR PLANT G:000'S OF $
VCPLNTH	-	VARIABLE COST FOR PLANT H:000'S OF $
VCPLNTI	-	VARIABLE COST FOR PLANT I:000'S OF $
VCPLNTJ	-	VARIABLE COST FOR PLANT J:000'S OF $
VCPLNTK	-	VARIABLE COST FOR PLANT K:000'S OF $
VCPLNTL	-	VARIABLE COST FOR PLANT L:000'S OF $
VCPLNTM	-	VARIABLE COST FOR PLANT M:000'S OF $
VCPLNTN	-	VARIABLE COST FOR PLANT N:000'S OF $
VCPLNTO	-	VARIABLE COST FOR PLANT O:000'S OF $
VCPPC	-	COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $
VCRTUE	-	TOTAL FUEL AND PURCHASED POWER EXPENSE REPORTED:000'S OF $

EXOGENOUS:

CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
COCTUE	-	NUMBER OF COMMERCIAL AND "OTHER" CUSTOMERS
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
D1	-	DUMMY FOR INDUSTRIAL PRICE EQUATION
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLNTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLNTC	-	GENERATION CAPABILITY OF PLANT C:MWH
GCPLNTD	-	GENERATION CAPABILITY OF PLANT D:MWH
GCPLNTE	-	GENERATION CAPABILITY OF PLANT E:MWH
GCPLNTF	-	GENERATION CAPABILITY OF PLANT F:MWH
GCPLNTG	-	GENERATION CAPABILITY OF PLANT G:MWH
GCPLNTH	-	GENERATION CAPABILITY OF PLANT H:MWH
GCPLNTI	-	GENERATION CAPABILITY OF PLANT I:MWH
GCPLNTJ	-	GENERATION CAPABILITY OF PLANT J:MWH
GCPLNTK	-	GENERATION CAPABILITY OF PLANT K:MWH
GCPLNTL	-	GENERATION CAPABILITY OF PLANT L:MWH
GCPLNTM	-	GENERATION CAPABILITY OF PLANT M:MWH
GCPLNTN	-	GENERATION CAPABILITY OF PLANT N:MWH
GCPPC	-	GENERATION CAPABILITY OF PURCAHSED POWER FROM NON-UTILITY SOURCES
ILFCOSTU	-	LOSS FACTOR: COMMERCIAL AND "OTHER" SALES
ILFISTUE	-	LOSS FACTOR: INDUSTRIAL SALES
ILFRSTUE	-	LOSS FACTOR: RESIDENTIAL SALES
ILFWSTUE	-	LOSS FACTOR: WHOLESALE SALES
ISTUE	-	INDUSTRIAL SALES: MWH
MATFCTUE	-	FOUR QUARTER MOVING SUM OF TOTAL FIXED COSTS:000'S OF $
NAGTUE	-	NON-AGRICULTURAL EMPLOYMENT IN TUEC SERVICE AREA:000'S OF PERSONS
Q1	-	FIRST QUARTER DUMMY VARIABLE
Q2	-	SECOND QUARTER DUMMY VARIABLE
Q3	-	THIRD QUARTER DUMMY VARIABLE
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RCTUE	-	RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPITUE	-	REAL PERSONAL INCOME (BILLIONS OF DOLLARS)

TFCTUE	-	TOTAL FIXED COSTS: 000'S OF $
UFCPLNTA	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT A:000'S OF $
UFCPLNTB	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT B:000'S OF $
UFCPLNTC	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT C:000'S OF $
UFCPLNTD	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT D:000'S OF $
UFCPLNTE	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT E:000'S OF $
UFCPLNTF	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT F:000'S OF $
UFCPLNTG	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT G:000'S OF $
UFCPLNTH	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT H:000'S OF $
UFCPLNTI	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT I:000'S OF $
UFCPLNTJ	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT J:000'S OF $
UFCPLNTK	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT K:000'S OF $
UFCPLNTL	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT L:000'S OF $
UFCPLNTM	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT M:000'S OF $
UFCPLNTN	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT N:000'S OF $
UFCPLNTO	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT O:000'S OF $
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH
VCRD1	-	DUMMY VARIABLE IN VCRTUE EQUATION
WSTUE	-	WHOLESALE SALES: MWH

IDENTITIES
RAPINST=(RAPTUE/CPITX)*RCTUE;
COAPINS=(COAPTUE/CPITX)*COCTUE;

TSTUE=RSTUE+COSTUE+ISTUE+WSTUE;

AFCTUE=MATFCTUE/
(TSTUE+TSTUE(-1)+TSTUE(-2)+TSTUE(-3));

```
AVCRTUE=VCRTUE/TSTUE;

GENRTUE = RSTUE * ILFRSTUE + COSTUE * ILFCOSTU +
 ISTUE* ILFISTUE + WSTUE*ILFWSTUE;

PPCC = GENRTUE-GCPPC;
PLNTAC = PPCC-GCPLNTA;
PLNTBC = PLNTAC-GCPLNTB;
PLNTCC = PLNTBC-GCPLNTC;
PLNTDC = PLNTCC-GCPLNTD;
PLNTEC = PLNTDC-GCPLNTE;
PLNTFC = PLNTEC-GCPLNTF;
PLNTGC = PLNTFC-GCPLNTG;
PLNTHC = PLNTGC-GCPLNTH;
PLNTIC = PLNTHC-GCPLNTI;
PLNTJC = PLNTIC-GCPLNTJ;
PLNTKC = PLNTJC-GCPLNTK;
PLNTLC = PLNTKC-GCPLNTL;
PLNTMC = PLNTLC-GCPLNTM;
PLNTNC = PLNTMC-GCPLNTN;

GRPPC = (PPCC>0)*GCPPC+(PPCC<0)*GENRTUE;
VCPPC = GRPPC*UFCPPC/1000;
GRPLNTA = (PPCC>0)*( (PLNTAC>0)*GCPLNTA+(PLNTAC<=0)*PPCC);
VCPLNTA = GRPLNTA*UFCPLNTA/1000;
GRPLNTB = (PPCC>0)*(PLNTAC>0)*( (PLNTBC>0)*GCPLNTB+
 (PLNTBC<=0)*PLNTAC );
VCPLNTB = GRPLNTB*UFCPLNTB/1000;
GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*( (PLNTCC>0)*GCPLNTC+
 (PLNTCC<=0)*PLNTBC );
VCPLNTC = GRPLNTC*UFCPLNTC/1000;
GRPLNTD = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 ( (PLNTDC>0)*GCPLNTD+(PLNTDC<=0)*PLNTCC );
VCPLNTD = GRPLNTD*UFCPLNTD/1000;
GRPLNTE = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
 ( (PLNTEC>0)*GCPLNTE+(PLNTEC<=0)*PLNTDC );
VCPLNTE = GRPLNTE*UFCPLNTE/1000;
GRPLNTF = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 ( (PLNTFC>0)*GCPLNTF+(PLNTFC<=0)*PLNTEC );
VCPLNTF = GRPLNTF*UFCPLNTF/1000;
GRPLNTG = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*( (PLNTGC>0)*GCPLNTG+(PLNTGC<=0)*PLNTFC );
VCPLNTG = GRPLNTG*UFCPLNTG/1000;
GRPLNTH = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*( (PLNTHC>0)*GCPLNTH+
 (PLNTHC<=0)*PLNTGC );
VCPLNTH = GRPLNTH*UFCPLNTH/1000;
GRPLNTI = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*(PLNTHC>0)*( (PLNTIC>0)*GCPLNTI+
```

```
 (PLNTIC<=0)*PLNTHC );
VCPLNTI = GRPLNTI*UFCPLNTI/1000;
GRPLNTJ = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*(PLNTHC>0)*(PLNTIC>0)*
 ( (PLNTJC>0)*GCPLNTJ+(PLNTJC<=0)*PLNTIC );
VCPLNTJ = GRPLNTJ*UFCPLNTJ/1000;
GRPLNTK = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*(PLNTHC>0)*(PLNTIC>0)*(PLNTJC>0)*
 ( (PLNTKC>0)*GCPLNTK+(PLNTKC<=0)*PLNTJC );
VCPLNTK = GRPLNTK*UFCPLNTK/1000;
GRPLNTL = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*(PLNTHC>0)*(PLNTIC>0)*(PLNTJC>0)*
 (PLNTKC>0)*( (PLNTLC>0)*GCPLNTL+(PLNTLC<=0)*PLNTKC );
VCPLNTL = GRPLNTL*UFCPLNTL/1000;
GRPLNTM = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*(PLNTHC>0)*(PLNTIC>0)*(PLNTJC>0)*
 (PLNTKC>0)*(PLNTLC>0)*( (PLNTMC>0)*GCPLNTM+
 (PLNTMC<=0)*PLNTLC );
VCPLNTM = GRPLNTM*UFCPLNTM/1000;
GRPLNTN = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*(PLNTHC>0)*(PLNTIC>0)*(PLNTJC>0)*
 (PLNTKC>0)*(PLNTLC>0)*(PLNTMC>0)*( (PLNTNC>0)*GCPLNTN+
 (PLNTNC<=0)*PLNTMC );
VCPLNTN = GRPLNTN*UFCPLNTN/1000;
GRPLNTO = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*(PLNTHC>0)*(PLNTIC>0)*(PLNTJC>0)*
 (PLNTKC>0)*(PLNTLC>0)*(PLNTMC>0)*(PLNTNC>0)*PLNTNC;
VCPLNTO = GRPLNTO*UFCPLNTO/1000;

VCETUE =
 VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+
 VCPLNTE+VCPLNTF+VCPLNTG+VCPLNTH+
 VCPLNTI+VCPLNTJ+VCPLNTK+VCPLNTL+
 VCPLNTM+VCPLNTN+VCPLNTO+VCPPC;
```

EQUATION ESTIMATES

EQUATION 1: RESIDENTIAL SALES

RSTUE=a0+a1*RAPINST+a2*RPITUE(-4)+a3*RCDDINST+a4*RHDDINST

Number of observations: 54
(Statistics based on transformed data)
Mean of dependent variable = .827237E+07
Std. dev. of dependent var. = .176305E+07
Sum of squared residuals = .693453E+13

Variance of residuals = .141521E+12
Std. error of regression = 376193.
R-squared = .957907
Adjusted R-squared = .954471
Durbin-Watson statistic = 1.96255
Rho (autocorrelation coef.) = -.426435
Standard error of rho = .123089
t-statistic for rho = -3.46443
Log of likelihood function = -767.244
(Statistics based on original data)
Mean of dependent variable = .581327E+07
Std. dev. of dependent var. = .168406E+07
Sum of squared residuals = .693453E+13
Variance of residuals = .141521E+12
Std. error of regression = 376193.
R-squared = .953915
Adjusted R-squared = .950152
Durbin-Watson statistic = 1.96255

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.118477E+07	273821.	-4.32680
RAPINST	-13.2457	5.06031	-2.61757
RPITUE(-4)	271335.	31384.4	8.64554
RCDDINST	.259599E-02	.154019E-03	16.8550
RHDDINST	.180534E-02	.156431E-03	11.5408

<u>EQUATION 2: COMMERCIAL SALES</u>

COSTUE= b0+b1*COAPINS+b2*NAGTUE(-4)+b3*CCDDINST+b4*CHDDINST

Number of observations: 55
(Statistics based on transformed data)
Mean of dependent variable = .268350E+07
Std. dev. of dependent var. = 922343.
Sum of squared residuals = .290369E+13
Variance of residuals = .580737E+11
Std. error of regression = 240985.
R-squared = .936794
Adjusted R-squared = .931737
Durbin-Watson statistic = 2.02160
Rho (autocorrelation coef.) = .509910
Standard error of rho = .115993
t-statistic for rho = 4.39604
Log of likelihood function = -757.008
(Statistics based on original data)
Mean of dependent variable = .540940E+07
Std. dev. of dependent var. = .129063E+07
Sum of squared residuals = .290369E+13
Variance of residuals = .580737E+11
Std. error of regression = 240985.
R-squared = .968446
Adjusted R-squared = .965922
Durbin-Watson statistic = 2.02160

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.375152E+07	654082.	-5.73556
CAPINST	-172.176	67.9667	-2.53324
NAGTUE(-4)	4293.42	304.886	14.0821
CCDDINST	.656173E-02	.388559E-03	16.8873
CHDDINST	.255410E-02	.422767E-03	6.04140

EQUATION 3: RESIDENTIAL AVERAGE PRICE

RAPTUE=c0+c1*AVCRTUE+c2*AFCTUE

Number of observations: 52
Mean of dependent variable = .060509
Std. dev. of dependent var. = .010597
Sum of squared residuals = .108270E-02
Variance of residuals = .220960E-04
Std. error of regression = .470064E-02
R-squared = .811171
Adjusted R-squared = .803464
Durbin-Watson statistic = 2.00382
F-statistic (zero slopes) = 105.106
E'PZ*E = .864264E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.323445E-02	.402595E-02	.803400
AVCRTUE	1.54253	.185176	8.33008
AFCTUE	.895200	.155283	5.76496

EQUATION 4: COMMERCIAL AVERAGE PRICE

COAPTUE=d0+d1*AVCRTUE+d2*AFCTUE

Number of observations: 52
Mean of dependent variable = .052836
Std. dev. of dependent var. = .716282E-02
Sum of squared residuals = .370704E-03
Variance of residuals = .756539E-05
Std. error of regression = .275052E-02
R-squared = .858459
Adjusted R-squared = .852682
Durbin-Watson statistic = 1.90270
F-statistic (zero slopes) = 148.433
E'PZ*E = .273968E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.014173	.235574E-02	6.01638
AVCRTUE	1.22395	.108353	11.2959
AFCTUE	.461075	.090862	5.07445

EQUATION 5: INDUSTRIAL AVERAGE PRICE

IAPTUE=e0+e1*AVCRTUE+e2*AFCTUE+e3*D1

Number of observations: 52
Mean of dependent variable = .037939
Std. dev. of dependent var. = .611095E-02
Sum of squared residuals = .298549E-03
Variance of residuals = .621976E-05
Std. error of regression = .249395E-02
R-squared = .843866
Adjusted R-squared = .834108
Durbin-Watson statistic = 2.53308
F-statistic (zero slopes) = 86.0687
E'PZ*E = .189212E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.543433E-02	.236968E-02	2.29327
AVCRTUE	1.15626	.109738	10.5366
AFCTUE	.327161	.124523	2.62732
D1	-.241957E-02	.106650E-02	-2.26870

EQUATION 6: TOTAL FUEL EXPENSE AND PURCHASED POWER COST

VCRTUE=f0+f1*VCETUE+f2*VCRD1+f3*Q1+f4*Q2+f5*Q3

Number of observations: 52
Mean of dependent variable = 379955.
Std. dev. of dependent var. = 111088.
Sum of squared residuals = .274252E+11
Variance of residuals = .596199E+09
Std. error of regression = 24417.2
R-squared = .956595
Adjusted R-squared = .951877
Durbin-Watson statistic = 2.16263
F-statistic (zero slopes) = 201.928
E'PZ*E = .138041E+11

Variable	Estimated Coefficient	Standard Error	t-statistic
C	21795.4	14025.3	1.55401
VCETUE	.980872	.039624	24.7545
VCRD1	49633.0	7571.02	6.55566
Q1	-25889.6	9603.30	-2.69590
Q2	45873.4	9643.61	4.75687
Q3	-41761.7	11549.8	-3.61581

4-2 HOUSTON LIGHTING & POWER COMPANY

MODEL: HL&P

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCHLP	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRHLP	-	AVERAGE FUEL AND PURCHASED POWER COSTS:000'S OF $ PER MWH
CAPHLP	-	COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
CAPINST	-	INSTRUMENT FOR CAPHLP
CSHLP	-	COMMERICAL SALES:MWH
GENRHLP	-	GENERATION REQUIREMENTS:MWH
GRNG1	-	GENERATION REQUIREMENTS FROM NATURAL GAS PLANT:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENT FROM PLANT D:MWH
GRPLNTE	-	GENERATION REQUIREMENT FROM PLANT E:MWH
GRPLNTF	-	GENERATION REQUIREMENT FROM PLANT F:MWH
GRPLNTG	-	GENERATION REQUIREMENT FROM PLANT G:MWH
GRPLNTH	-	GENERATION REQUIREMENT FROM PLANT H:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPHLP	-	INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
IAPINST	-	INSTRUMENT FOR IAPHLP
ISHLP	-	INDUSTRIAL SALES:MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE
PLNTEC	-	CONDITIONAL VARIABLE
PLNTFC	-	CONDITIONAL VARIABLE
PLNTGC	-	CONDITIONAL VARIABLE
PLNTHC	-	CONDITIONAL VARIABLE

PPCC	-	CONDITIONAL VARIABLE
RAPHLP	-	RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
RAPINST	-	INSTRUMENT FOR RAPHLP
RSHLP	-	RESIDENTIAL SALES:MWH
TSHLP	-	TOTAL SYSTEM SALES:MWH
VCEHLP	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE: 000'S OF $
VCNG1	-	NATURAL GAS COST:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A: 000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B: 000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANT C: 000'S OF $
VCPLNTD	-	VARIABLE COST FOR PLANT D: 000'S OF $
VCPLNTE	-	VARIABLE COST FOR PLANT E: 000'S OF $
VCPLNTF	-	VARIABLE COST FOR PLANT F: 000'S OF $
VCPLNTG	-	VARIABLE COST FOR PLANT G: 000'S OF $
VCPLNTH	-	VARIABLE COST FOR PLANT H: 000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $
VCRHLP	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST REPORTED:000'S OF $

EXOGENOUS:

APDUM	-	DUMMY IN AVERAGE PRICE EQUATIONS
CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CCHLP	-	COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
CDDHLP	-	COOLING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
CSDUM	-	DUMMY IN COMMERCIAL SALES EQUATION
GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLNTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLNTC	-	GENERATION CAPABILITY OF PLANT C:MWH
GCPLNTD	-	GENERATION CAPABILITY OF PLANT D:MWH
GCPLNTE	-	GENERATION CAPABILITY OF PLANT E:MWH
GCPLNTF	-	GENERATION CAPABILITY OF PLANT F:MWH
GCPLNTG	-	GENERATION CAPABILITY OF PLANT G:MWH

GCPLNTH	-	GENERATION CAPABILITY OF PLANT H:MWH
ILFCSHLP	-	LOSS FACTOR: COMMERCIAL SALES
ILFISHLP	-	LOSS FACTOR: INDUSTRIAL SALES
ILFOSHLP	-	LOSS FACTOR: OTHER SALES
ILFRSHLP	-	LOSS FACTOR: RESIDENTIAL SALES
ISDUM	-	DUMMY IN INDUSTRIAL SALES EQUATION
MATFCHLP	-	FOUR QUARTER MOVING SUM TOTAL FIXED COSTS:000'S OF DOLLARS
OSHLP	-	OTHER RETAIL SALES: MWH
NAGHLP	-	NON-AGRICULTURAL EMPLOYMENT IN HLP SERVICE AREA: 000'S OF PERSONS
PNGCHLP	-	PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS: $ PER MCF
PNGIHLP	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS: $ PER MCF
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RCHLP	-	RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPIHLP	-	REAL PERSONAL INCOME (BILLIONS OF DOLLARS)
UFCNG1	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN NATURAL GAS PLANT: 000'S OF $
UFCPLNTA	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT A :000'S OF $
UFCPLNTB	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT B:000'S OF $
UFCPLNTC	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT C:000'S OF $
UFCPLNTD	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT D: 000'S OF $
UFCPLNTE	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT E:000'S OF $
UFCPLNTF	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT F:000'S OF $
UFCPLNTG	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT G:000'S OF $
UFCPLNTH	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT H:000'S OF $
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH

IDENTITIES

```
RAPINST=(RAPHIP/CPITX)*RCHLP;
CAPINST=(CAPHLP(-4)/PNGCHLP(-4))*CCHLP;
IAPINST=IAPHLP/PNGIHLP;

TSHLP=RSHLP+CSHLP+ISHLP+OSHLP;
AFCHLP=MATFCHLP/
 (TSHLP+TSHLP(-1)+TSHLP(-2)+TSHLP(-3));

AVCRHLP=VCRHLP/TSHLP;

GENRHLP = RSHLP * ILFRSHLP + CSHLP * ILFCSHLP +
 ISHLP* ILFISHLP + OSHLP*ILFoSHLP;

PPCC = GENRHLP-GCPPC;
PLNTAC = PPCC-GCPLNTA;
PLNTBC = PLNTAC-GCPLNTB;
PLNTCC = PLNTBC-GCPLNTC;
PLNTDC = PLNTCC-GCPLNTD;
PLNTEC = PLNTDC-GCPLNTE;
PLNTFC = PLNTEC-GCPLNTF;
PLNTGC = PLNTFC-GCPLNTG;
PLNTHC = PLNTGC-GCPLNTH;
GRPPC = (PPCC>0)*GCPPC+(PPCC<0)*GENRHlp;
VCPPC = GRPPC*UFCPPC/1000;
GRPLNTA = (PPCC>0)*( (PLNTAC>0)*GCPLNTA+(PLNTAC<0)*PPCC);
VCPLNTA = GRPLNTA*UFCPLNTA/1000;
GRPLNTB = (PPCC>0)*(PLNTAC>0)*( (PLNTBC>0)*GCPLNTB+
 (PLNTBC<0)*PLNTAC );
VCPLNTB = GRPLNTB*UFCPLNTB/1000;
GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*( (PLNTCC>0)*GCPLNTC+
 (PLNTCC<0)*PLNTBC );
VCPLNTC = GRPLNTC*UFCPLNTC/1000;
GRPLNTD = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 ( (PLNTDC>0)*GCPLNTD+(PLNTDC<0)*PLNTCC );
VCPLNTD = GRPLNTD*UFCPLNTD/1000;
GRPLNTE = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
 ( (PLNTEC>0)*GCPLNTE+(PLNTEC<0)*PLNTDC );
VCPLNTE = GRPLNTE*UFCPLNTE/1000;
GRPLNTF = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 ( (PLNTFC>0)*GCPLNTF+(PLNTFC<0)*PLNTEC );
VCPLNTF = GRPLNTF*UFCPLNTF/1000;
GRPLNTG = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*( (PLNTGC>0)*GCPLNTG+(PLNTGC<0)*PLNTFC );
VCPLNTG = GRPLNTG*UFCPLNTG/1000;
GRPLNTH = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*( (PLNTHC>0)*GCPLNTH+
 (PLNTHC<0)*PLNTGC );
VCPLNTH = GRPLNTH*UFCPLNTH/1000;
```

```
GRngl = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*(PLNTGC>0)*(PLNTHC>0)*PLNThC;
VCngl = GRngl*UFCngl/1000;

VCEHlp =
 VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+
 VCPLNTE+VCPLNTF+VCPLNTG+VCPLNTH+
 VCNgl;
```

EQUATION ESTIMATES

EQUATION 1: RESIDENTIAL SALES

RSHLP=a0+a1*RSHLP(-1)+a2*RAPINST+a3*RPIHLP+a4*RCDDINST+a5*RHDDINST

Number of observations: 57
Mean of dependent variable = .350799E+07
Std. dev. of dependent var. = .110031E+07
Sum of squared residuals = .799359E+13
Variance of residuals = .156737E+12
Std. error of regression = 395900.
R-squared = .882455
Adjusted R-squared = .870930
Durbin-Watson statistic = 3.19866
F-statistic (zero slopes) = 76.3113
E'PZ*E = .413501E+12

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-232009.	626172.	-.370520
RSHLP(-1)	.332730	.094662	3.51494
RAPINST	-11.5100	5.76407	-1.99686
RPIHLP	34258.0	101057.	.338996
RCDDINST	.266962E-02	.210660E-03	12.6727
RHDDINST	.191564E-02	.273710E-03	6.99879

EQUATION 2: COMMERCIAL SALES

CSHLP=b0+b1*CSHLP(-4)+b2*CAPINST+b3*NAGHLP+b4*CCDDINST+b5*CSDUM

Number of observations: 54
(Statistics based on transformed data)
Mean of dependent variable = .199760E+07
Std. dev. of dependent var. = 369052.
Sum of squared residuals = .290083E+12
Variance of residuals = .604339E+10
Std. error of regression = 77739.3
R-squared = .960053
Adjusted R-squared = .955892
Durbin-Watson statistic = 2.04996
Rho (autocorrelation coef.) = .263897
Standard error of rho = .131259
t-statistic for rho = 2.01051

Log of likelihood function = -681.543
(Statistics based on original data)
Mean of dependent variable = .270724E+07
Std. dev. of dependent var. = 403631.
Sum of squared residuals = .290083E+12
Variance of residuals = .604339E+10
Std. error of regression = 77739.3
R-squared = .966565
Adjusted R-squared = .963082
Durbin-Watson statistic = 2.04996

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-351649.	251397.	-1.39878
CSHLP(-4)	.913986	.065712	13.9090
CAPINST	-73.1298	49.0007	-1.49242
NAGHLP	509.378	180.893	2.81591
CCDDINST	.358551E-03	.221472E-03	1.61894
CSDUM	-212255.	70497.6	-3.01082

EQUATION 3: INDUSTRIAL SALES

ISHLP=c0+c1*ISHLP(-1)+c2*IAPINST+c3*NAGHLP+c4*CDDHLP+c5*ISDUM

Number of observations: 53
Mean of dependent variable = .721736E+07
Std. dev. of dependent var. = 483957.
Sum of squared residuals = .331309E+13
Variance of residuals = .704913E+11
Std. error of regression = 265502.
R-squared = .730564
Adjusted R-squared = .701900
Durbin-Watson statistic = 2.80592
F-statistic (zero slopes) = 25.1551
E'PZ*E = .124952E+13

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.267317E+07	943162.	2.83427
ISHLP(-1)	.357155	.166792	2.14131
IAPINST	-.602419E+08	.256145E+08	-2.35187
NAGHLP	1560.08	764.682	2.04017
CDDHLP	507.838	74.9871	6.77233
ISDUM	-527472.	120937.	-4.36155

EQUATION 4: RESIDENTIAL AVERAGE PRICE

RAPHLP=d0+d1*AVCRHLP+d2*AFCHLP+d3*APDUM

Number of observations: 57
Mean of dependent variable = .068765
Std. dev. of dependent var. = .018006
Sum of squared residuals = .184840E-02
Variance of residuals = .348755E-04

Std. error of regression = .590555E-02
R-squared = .898424
Adjusted R-squared = .892675
Durbin-Watson statistic = 2.17860
F-statistic (zero slopes) = 155.865
E'PZ*E = .727899E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.217152E-02	.345136E-02	-.629177
AVCRHLP	1.03590	.105215	9.84550
AFCHLP	1.59482	.106021	15.0425
APDUM	-.505151E-02	.219532E-02	-2.30103

EQUATION 5: COMMERCIAL AVERAGE PRICE

CAPHLP=c0+c1*AVCRHLP+c2*AFCHLP+c3*APDUM

Number of observations: 52
(Statistics based on transformed data)
Mean of dependent variable = .075129
Std. dev. of dependent var. = .012628
Sum of squared residuals = .778396E-03
Variance of residuals = .162166E-04
Std. error of regression = .402698E-02
R-squared = .904548
Adjusted R-squared = .898582
Durbin-Watson statistic = 2.06715
Rho (autocorrelation coef.) = -.183812
Standard error of rho = .135020
t-statistic for rho = -1.36136
Log of likelihood function = 215.063
(Statistics based on original data)
Mean of dependent variable = .063596
Std. dev. of dependent var. = .010772
Sum of squared residuals = .778396E-03
Variance of residuals = .162166E-04
Std. error of regression = .402698E-02
R-squared = .869004
Adjusted R-squared = .860817
Durbin-Watson statistic = 2.06715

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.630459E-02	.277974E-02	2.26805
AVCRHLP	.967691	.071483	13.5374
AFCHLP	1.05780	.065949	16.0398
APDUM	-.402096E-02	.124377E-02	-3.23289

EQUATION 6: INDUSTRIAL AVERAGE PRICE

IAPHLP=f0+f1*AVCRHLP+f2*AFCHLP+f3*APDUM

Number of observations: 55

(Statistics based on transformed data)
Mean of dependent variable = .051005
Std. dev. of dependent var. = .011479
Sum of squared residuals = .599877E-03
Variance of residuals = .117623E-04
Std. error of regression = .342962E-02
R-squared = .915900
Adjusted R-squared = .910953
Durbin-Watson statistic = 2.25525
Rho (autocorrelation coef.) = -.268922
Standard error of rho = .128708
t-statistic for rho = -2.08940
Log of likelihood function = 236.177
(Statistics based on original data)
Mean of dependent variable = .040288
Std. dev. of dependent var. = .920424E-02
Sum of squared residuals = .599877E-03
Variance of residuals = .117623E-04
Std. error of regression = .342962E-02
R-squared = .869602
Adjusted R-squared = .861932
Durbin-Watson statistic = 2.25525

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.170167E-02	.176748E-02	.962767
AVCRHLP	1.01981	.051215	19.9124
AFCHLP	.375461	.049476	7.58871
APDUM	-.244987E-02	.990371E-03	-2.47369

EQUATION 7: TOTAL FUEL EXPENSE AND PURCHASED POWER COST

VCRHLP=g0+g1*VCEHLP

Number of observations: 56
Mean of dependent variable = 377255.
Std. dev. of dependent var. = 117907.
Sum of squared residuals = .158308E+12
Variance of residuals = .293163E+10
Std. error of regression = 54144.5
R-squared = .793125
Adjusted R-squared = .789294
Durbin-Watson statistic = .929501
F-statistic (zero slopes) = 206.817
E'PZ*E = .124209E+12

Variable	Estimated Coefficient	Standard Error	t-statistic
C	95037.8	20960.8	4.53408
VCEHLP	.888429	.061929	14.3458

4-3 GULF STATES UTILITIES COMPANY

MODEL: GSU

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCGSU	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRGSU	-	AVERAGE FUEL AND PURCAHSED POWER COSTS: 000'S OF $ PER MWH
CAPGSUN	-	COMMERCIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
CAPGSUT	-	COMMERCIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
CSGSUN	-	COMMERCIAL SALES (NON-TEXAS):MWH
CSGSUT	-	COMMERCIAL SALES (TEXAS):MWH
GENRGSU	-	GENERATION REQUIREMENTS:MWH
GRNG	-	GENERATION REQUIREMENTS FROM NATURAL GAS PLANT:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENT FROM PLANT D:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPGSUT	-	INDUSTRIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
IAPINST	-	INSTRUMENT FOR IAPGSUT
ISGSUT	-	INDUSTRIAL SALES (TEXAS):MWH
OAPGSUT	-	OTHER RETAIL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
OSGSUT	-	OTHER RETAIL SALES (TEXAS): MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RAPGSUN	-	RESIDENTIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
RAPGSUT	-	RESIDENTIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
RAPINSN	-	INSTRUMENT FOR RAPGSUN

RAPINST	-	INSTRUMENT FOR RAPGSUT
RSGSUN	-	RESIDENTIAL SALES (NON-TEXAS):MWH
RSGSUT	-	RESIDENTIAL SALES (TEXAS):MWH
TSGSU	-	TOTAL SYSTEM SALES:MWH
TSGSUN	-	TOTAL NON-TEXAS SYSTEM SALES:MWH
TSGSUT	-	TOTAL TEXAS SYSTEM SALES:MWH
VCEGSU	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE:000'S OF $
VCNG	-	NATURAL GAS COST:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANTA:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANTB:000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANTC:000'S OF $
VCPLNTD	-	VARIABLE COST FOR PLANTD:000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S
VCRGSU	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST REPORTED:000'S OF $

EXOGENOUS:

CCDDINSN	-	INSTRUMENT FOR (NON-TEXAS) COMMERCIAL COOLING DEGREE DAYS
CCDDINST	-	INSTRUMENT FOR (TEXAS) COMMERCIAL COOLING DEGREE DAYS
CDDGSUT	-	TEXAS COOLING DEGREE DAYS
CHDDINSN	-	INSTRUMENT FOR (NON-TEXAS) COMMERCIAL HEATING DEGREE DAYS
CHDDINST	-	INSTRUMENT FOR (TEXAS) COMMERCIAL HEATING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
GCPLANTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLANTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLANTC	-	GENERATION CAPABILITY OF PLANT C:MWH
GCPLANTD	-	GENERATION CAPABILITY OF PLANT D:MWH
GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
ILFCSGSU	-	LOSS FACTOR:COMMERCIAL SALES
ILFISGSU	-	LOSS FACTOR:INDUSTRIAL SALES
ILFOSGSU	-	LOSS FACTOR:OTHER SALES
ILFRSGSU	-	LOSS FACTOR:RESIDENTIAL SALES

ILFWSGSU	-	LOSS FACTOR:WHOLESALE SALES
ISGSUN	-	INDUSTRIAL SALES (NON-TEXAS):MWH
MATFCGSU	-	FOUR-QUARTER MOVING AVERAGE TOTAL FIXED COSTS: 000'S OF $
OSGSUN	-	OTHER NON-TEXAS SALES:MWH
PNGIGSU	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS: $ PER MCF
POPGSUT	-	SERVICE AREA POPULATION (TEXAS):THOUSANDS OF PERSONS
RCDDINSN	-	INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL COOLING DEGREE DAYS
RCDDINST	-	INSTRUMENT FOR (TEXAS) RESIDENTIAL COOLING DEGREE DAYS
RCGSUT	-	RESIDENTIAL CUSTOMERS (TEXAS): NUMBER OF CUSTOMERS
RHDDINSN	-	INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL HEATING DEGREE DAYS
RHDDINST	-	INSTRUMENT FOR (TEXAS) RESIDENTIAL HEATING DEGREE DAYS
RPIGSUN	-	REAL NON-TEXAS PERSONAL INCOME(BILLIONS OF DOLLARS)
UFCNG	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN NATURAL GAS PLANT:000'S OF $
UFCPLANTA	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANTA:000'S OF $ PER MWH
UFCPLANTB	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANTB:000'S OF $ PER MWH
UFCPLANTC	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANTC:000'S OF $ PER MWH
UFCPLANTD	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANTD:000'S OF $ PER MWH
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH
WSGSUN	-	WHOLESALE NON-TEXAS SALES:MWH
WSGSUT	-	WHOLESALE TEXAS SALES:MWH

IDENTITIES

RAPINST=(RAPGSUT/CPITX)*RCGSUT;
IAPINST=IAPGSUT/PNGIGSU;

TSGSUT=RSGSUT+CSGSUT+ISGSUT+OSGSUT+WSGSUT;
TSGSUN=RSGSUN+CSGSUN+ISGSUN+OSGSUN+WSGSUN;
TSGSU=TSGSUT+TSGSUN;

```
AFCGSU=MATFCGSU/
 (TSGSU+TSGSU(-1)+TSGSU(-2)+TSGSU(-3));

AVCRGSU=VCRGSU/TSGSU;

GENRGSU = (RSGSUT+RSGSUN)*ILFRSGSU+
 (CSGSUT+CSGSUN)*ILFCSGSU+
 (ISGSUT+ISGSUN)*ILFISGSU+
 (OSGSUT+OSGSUN)*ILFOSGSU+
 (WSGSUT+WSGSUN)*ILFWSGSU;

PPCC = GENRGSU-GCPPC;
PLNTAC = PPCC-GCPLNTA;
PLNTBC = PLNTAC-GCPLNTB;
PLNTCC = PLNTBC-GCPLNTC;
PLNTDC = PLNTCC-GCPLNTD;

GRPPC = (PPCC>0)*GCPPC+(PPCC<=0)*GENRGSU;
VCPPC = GRPPC*UFCPPC/1000;
GRPLNTA = (PPCC>0)*( (PLNTAC>0)*GCPLNTA+(PLNTAC<=0)*PPCC);
VCPLNTA = GRPLNTA*UFCPLNTA/1000;
GRPLNTB = (PPCC>0)*(PLNTAC>0)*( (PLNTBC>0)*GCPLNTB+
 (PLNTBC<=0)*PLNTAC );
VCPLNTB = GRPLNTB*UFCPLNTB/1000;
GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*( (PLNTCC>0)*GCPLNTC+
 (PLNTCC<=0)*PLNTBC );
VCPLNTC = GRPLNTC*UFCPLNTC/1000;
GRPLNTD = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 ( (PLNTDC>0)*GCPLNTD+(PLNTDC<=0)*PLNTCC );
VCPLNTD = GRPLNTD*UFCPLNTD/1000;
GRNG = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*PLNTDC;
VCNG = GRNG*UFCNG/1000;

VCEGSU = VCPPC+
 VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+VCNG;
```

EQUATION ESTIMATES

<u>EQUATION 1: TEXAS RESIDENTIAL SALES</u>

RSGSUT=a0+a1*RSGSUT(-4)+a2*RAPINST+a3*RCDDINST*a4*RHDDINST

Number of observations: 54
(Statistics based on transformed data)
Mean of dependent variable = 604715.
Std. dev. of dependent var. = 199514.
Sum of squared residuals = .101232E+12
Variance of residuals = .206595E+10
Std. error of regression = 45452.7
R-squared = .952155
Adjusted R-squared = .948250

Durbin-Watson statistic = 1.98986
Rho (autocorrelation coef.) = .193607
Standard error of rho = .133508
t-statistic for rho = 1.45015
Log of likelihood function = -653.118
(Statistics based on original data)
Mean of dependent variable = 749044.
Std. dev. of dependent var. = 189212.
Sum of squared residuals = .101232E+12
Variance of residuals = .206595E+10
Std. error of regression = 45452.7
R-squared = .946669
Adjusted R-squared = .942315
Durbin-Watson statistic = 1.98986

Variable	Estimated Coefficient	Standard Error	t-statistic
C	74370.1	56463.3	1.31714
RSGSUT(-4)	.765171	.077036	9.93265
RAPINST	-4.27633	3.92455	-1.08964
RCDDINST	.654461E-03	.190453E-03	3.43633
RHDDINST	.658768E-03	.213331E-03	3.08802

EQUATION 2: NON TEXAS RESIDENTIAL SALES

RSGSUN=b0+b1*RSGSUN(-1)+b2*RPIGSUN(-1)+b3*RCDDINSN+b4*RHDDINSN

Number of observations: 59
Mean of dependent variable = 767753.
Std. dev. of dependent var. = 220606.
Sum of squared residuals = .302489E+12
Variance of residuals = .560165E+10
Std. error of regression = 74844.2
R-squared = .892837
Adjusted R-squared = .884899
Durbin-Watson statistic = 2.58703
Durbin's h alternative = -2.46515
F-statistic (zero slopes) = 112.476
Schwarz Bayes. Info. Crit. = 22.7033
Log of likelihood function = -743.272

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-175716.	140819.	-1.24781
RSGSUN(-1)	.199234	.050405	3.95265
RPIGSUN(-1)	91726.7	65892.5	1.39207
RCDDINSN	.261920E-02	.174511E-03	15.0088
RHDDINSN	.172063E-02	.233225E-03	7.37755

EQUATION 3: TEXAS COMMERCIAL SALES

CSGSUT=c0+c1*CSGSUT(-1)+c2*POPGSUT(-4)+c3*CCDDINST+c4*CHDDINST

Number of observations: 54
(Statistics based on transformed data)
Mean of dependent variable = 305115.
Std. dev. of dependent var. = 70546.8
Sum of squared residuals = .125986E+11
Variance of residuals = .257115E+09
Std. error of regression = 16034.8
R-squared = .952237
Adjusted R-squared = .948338
Durbin-Watson statistic = 2.40998
Rho (autocorrelation coef.) = .373285
Standard error of rho = .138681
t-statistic for rho = 2.69169
F-statistic (zero slopes) = 244.224
Log of likelihood function = -596.855
(Statistics based on original data)
Mean of dependent variable = 484856.
Std. dev. of dependent var. = 81584.6
Sum of squared residuals = .125986E+11
Variance of residuals = .257115E+09
Std. error of regression = 16034.8
R-squared = .964317
Adjusted R-squared = .961404
Durbin-Watson statistic = 2.40998

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-308688.	62203.8	-4.96252
CSGSUT(-1)	.261412	.040483	6.45727
POPGSUT(-4)	670.335	89.0904	7.52421
CCDDINST	.510343E-02	.261247E-03	19.5348
CHDDINST	.288408E-02	.408900E-03	7.05328
RHO	.373285	.138681	2.69169

<u>EQUATION 4: NON TEXAS COMMERCIAL SALES</u>

CSGSUN=d0+d1*CSGSUN(-4)+d2*RPIGSUN(-4)+d3*CCDDINSN+d4*CHDDINSN

Number of observations: 54
(Statistics based on transformed data)
Mean of dependent variable = 428442.
Std. dev. of dependent var. = 99860.4
Sum of squared residuals = .275429E+11
Variance of residuals = .562100E+09
Std. error of regression = 23708.6
R-squared = .948049
Adjusted R-squared = .943808
Durbin-Watson statistic = 2.04593
Rho (autocorrelation coef.) = .377744
Standard error of rho = .126000
t-statistic for rho = 2.99796
Log of likelihood function = -617.973
(Statistics based on original data)
Mean of dependent variable = 686226.

Std. dev. of dependent var. = 108936.
Sum of squared residuals = .275429E+11
Variance of residuals = .562100E+09
Std. error of regression = 23708.6
R-squared = .956214
Adjusted R-squared = .952640
Durbin-Watson statistic = 2.04593

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-4081.04	89496.8	-.045600
CSGSUN(-4)	.821474	.081965	10.0222
RPIGSUN(-4)	44505.1	44496.1	1.00020
CCDDINSN	.132896E-02	.589503E-03	2.25438
CHDDINSN	.675539E-03	.535310E-03	1.26196

EQUATION 5: TEXAS INDUSTRIAL SALES

ISGSUT=e0+e1*IAPINST(-1)+e2*POPGSUT(-1)+e3*CDDGSUT

Number of observations: 48
(Statistics based on transformed data)
Mean of dependent variable = 692375.
Std. dev. of dependent var. = 61296.7
Sum of squared residuals = .117754E+12
Variance of residuals = .267623E+10
Std. error of regression = 51732.3
R-squared = .333211
Adjusted R-squared = .287749
Durbin-Watson statistic = 1.80917
Rho (autocorrelation coef.) = .536450
Standard error of rho = .120562
t-statistic for rho = 4.44959
Log of likelihood function = -587.005
(Statistics based on original data)
Mean of dependent variable = .149316E+07
Std. dev. of dependent var. = 71880.1
Sum of squared residuals = .117754E+12
Variance of residuals = .267623E+10
Std. error of regression = 51732.3
R-squared = .515090
Adjusted R-squared = .482028
Durbin-Watson statistic = 1.80917

Variable	Estimated Coefficient	Standard Error	t-statistic
C	607033.	486283.	1.24831
IAPINST(-1)	-.740929E+07	.640157E+07	-1.15742
POPGSUT(-1)	1129.94	636.768	1.77449
CDDGSUT	50.6986	11.2889	4.49101

EQUATION 6: TEXAS OTHER SALES

OSGSUT=f0+f1*OSGSUT(-1)+f2*CDDGSUT

Number of observations: 56
(Statistics based on transformed data)
Mean of dependent variable = 49723.3
Std. dev. of dependent var. = 5854.61
Sum of squared residuals = .673451E+08
Variance of residuals = .127066E+07
Std. error of regression = 1127.24
R-squared = .964277
Adjusted R-squared = .962929
Durbin-Watson statistic = 1.82499
Rho (autocorrelation coef.) = -.593572
Standard error of rho = .118221
t-statistic for rho = -5.02088
F-statistic (zero slopes) = 715.319
Log of likelihood function = -471.460
(Statistics based on original data)
Mean of dependent variable = 31291.5
Std. dev. of dependent var. = 3740.00
Sum of squared residuals = .673451E+08
Variance of residuals = .127066E+07
Std. error of regression = 1127.24
R-squared = .912496
Adjusted R-squared = .909194
Durbin-Watson statistic = 1.82499

Variable	Estimated Coefficient	Standard Error	t-statistic
C	392.598	839.567	.467619
OSGSUT(-1)	.966557	.026407	36.6024
CDDGSUT	1.21979	.227924	5.35175
RHO	-.593572	.118221	-5.02088

EQUATION 7: TEXAS RESIDENTIAL PRICE

RAPGSUT=g0+g1*AVCRGSU+g2*AFCGSU

Number of observations: 54
(Statistics based on transformed data)
Mean of dependent variable = .815679E-02
Std. dev. of dependent var. = .512793E-02
Sum of squared residuals = .115967E-02
Variance of residuals = .227387E-04
Std. error of regression = .476851E-02
R-squared = .168512
Adjusted R-squared = .135904
Durbin-Watson statistic = 1.92489
Rho (autocorrelation coef.) = .892596
Standard error of rho = .061354
t-statistic for rho = 14.5483
Log of likelihood function = 213.590
(Statistics based on original data)
Mean of dependent variable = .069089
Std. dev. of dependent var. = .015643

Sum of squared residuals = .115967E-02
Variance of residuals = .227387E-04
Std. error of regression = .476851E-02
R-squared = .910691
Adjusted R-squared = .907188
Durbin-Watson statistic = 1.92489

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.054916	.017875	3.07224
AVCRGSU	.533501	.213247	2.50180
AFCGSU	.249177	.511572	.487081

EQUATION 8: TEXAS COMMERCIAL PRICE

CAPGSUT=h0+h1*AVCRGSU+h2*AFCGSU

Number of observations: 54
(Statistics based on transformed data)
Mean of dependent variable = .010066
Std. dev. of dependent var. = .403191E-02
Sum of squared residuals = .462670E-03
Variance of residuals = .907196E-05
Std. error of regression = .301197E-02
R-squared = .463008
Adjusted R-squared = .441949
Durbin-Watson statistic = 2.03248
Rho (autocorrelation coef.) = .848462
Standard error of rho = .072023
t-statistic for rho = 11.7805
Log of likelihood function = 238.399
(Statistics based on original data)
Mean of dependent variable = .062139
Std. dev. of dependent var. = .013774
Sum of squared residuals = .462670E-03
Variance of residuals = .907196E-05
Std. error of regression = .301197E-02
R-squared = .954154
Adjusted R-squared = .952356
Durbin-Watson statistic = 2.03248

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.030068	.829744E-02	3.62382
AVCRGSU	.656145	.140710	4.66309
AFCGSU	.659013	.247232	2.66556

EQUATION 9: TEXAS INDUSTRIAL PRICE

IAPGSUT=i0+i1*AVCRGSU+i2*AFCGSU

Number of observations: 54
(Statistics based on transformed data)

Mean of dependent variable = .010229
Std. dev. of dependent var. = .312444E-02
Sum of squared residuals = .252844E-03
Variance of residuals = .495773E-05
Std. error of regression = .222660E-02
R-squared = .513354
Adjusted R-squared = .494270
Durbin-Watson statistic = 2.16054
Rho (autocorrelation coef.) = .732082
Standard error of rho = .092702
t-statistic for rho = 7.89718
Log of likelihood function = 254.714
(Statistics based on original data)
Mean of dependent variable = .037230
Std. dev. of dependent var. = .668791E-02
Sum of squared residuals = .252844E-03
Variance of residuals = .495773E-05
Std. error of regression = .222660E-02
R-squared = .893375
Adjusted R-squared = .889194
Durbin-Watson statistic = 2.16054

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.019518	.363388E-02	5.37114
AVCRGSU	.523403	.108464	4.82561
AFCGSU	.216166	.109799	1.96875

EQUATION 10: TEXAS OTHER PRICE

OAPGSUT=j0+j1*AVCRGSU+j2*AFCGSU

Number of observations: 54
(Statistics based on transformed data)
Mean of dependent variable = .022581
Std. dev. of dependent var. = .651181E-02
Sum of squared residuals = .104080E-02
Variance of residuals = .204078E-04
Std. error of regression = .451750E-02
R-squared = .537036
Adjusted R-squared = .518880
Durbin-Watson statistic = 2.12021
Rho (autocorrelation coef.) = .680866
Standard error of rho = .099668
t-statistic for rho = 6.83134
Log of likelihood function = 216.510
(Statistics based on original data)
Mean of dependent variable = .068814
Std. dev. of dependent var. = .016330
Sum of squared residuals = .104080E-02
Variance of residuals = .204078E-04
Std. error of regression = .451750E-02
R-squared = .926360

Adjusted R-squared = .923472
Durbin-Watson statistic = 2.12021

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.024998	.635521E-02	3.93351
AVCRGSU	.643841	.220585	2.91879
AFCGSU	1.03425	.190654	5.42473

EQUATION 11: NON TEXAS RESIDENTIAL PRICE

RAPGSUN=k0+k1*AVCRGSU+k2*AFCGSU

Number of observations: 55
(Statistics based on transformed data)
Mean of dependent variable = .020050
Std. dev. of dependent var. = .599137E-02
Sum of squared residuals = .966401E-03
Variance of residuals = .185846E-04
Std. error of regression = .431099E-02
R-squared = .501685
Adjusted R-squared = .482519
Durbin-Watson statistic = 1.95269
Rho (autocorrelation coef.) = .679115
Standard error of rho = .098977
t-statistic for rho = 6.86135
Log of likelihood function = 223.063
(Statistics based on original data)
Mean of dependent variable = .061128
Std. dev. of dependent var. = .014387
Sum of squared residuals = .966401E-03
Variance of residuals = .185846E-04
Std. error of regression = .431099E-02
R-squared = .913561
Adjusted R-squared = .910236
Durbin-Watson statistic = 1.95269

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.022889	.584714E-02	3.91457
AVCRGSU	.586616	.211100	2.77885
AFCGSU	.886187	.176523	5.02024

EQUATION 12: NON TEXAS COMMERCIAL PRICE

CAPGSUN=l0+l1*AVCRGSU+l2*AFCGSU

Number of observations: 55
(Statistics based on transformed data)
Mean of dependent variable = .987749E-02
Std. dev. of dependent var. = .396226E-02
Sum of squared residuals = .469410E-03
Variance of residuals = .902711E-05
Std. error of regression = .300452E-02

R-squared = .446977
Adjusted R-squared = .425707
Durbin-Watson statistic = 1.86229
Rho (autocorrelation coef.) = .827846
Standard error of rho = .075639
t-statistic for rho = 10.9447
Log of likelihood function = 242.921
(Statistics based on original data)
Mean of dependent variable = .054601
Std. dev. of dependent var. = .012533
Sum of squared residuals = .469410E-03
Variance of residuals = .902711E-05
Std. error of regression = .300452E-02
R-squared = .944886
Adjusted R-squared = .942767
Durbin-Watson statistic = 1.86229

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.024328	.705893E-02	3.44638
AVCRGSU	.666766	.141312	4.71841
AFCGSU	.565631	.213076	2.65460

EQUATION 13: TOTAL FUEL COST

VCRGSU=m0+m1*VCEGSU

Number of observations: 57
Mean of dependent variable = 159701.
Std. dev. of dependent var. = 41938.9
Sum of squared residuals = .254245E+11
Variance of residuals = .462264E+09
Std. error of regression = 21500.3
R-squared = .742029
Adjusted R-squared = .737339
Durbin-Watson statistic = 1.51028
F-statistic (zero slopes) = 158.075
E'PZ*E = .148763E+11

Variable	Estimated Coefficient	Standard Error	t-statistic
C	29982.7	10667.9	2.81056
VCEGSU	1.01261	.080254	12.6176

4-4 CENTRAL POWER AND LIGHT COMPANY

MODEL: CPL

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCCPL	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRCPL	-	AVERAGE FUEL EXPENSES AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CAPCPL	-	COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
CAPINST	-	INSTRUMENT FOR CAPCPL
CSCPL	-	COMMERCIAL SALES:MWH
GENRCPL	-	GENERATION REQUIREMENTS:MWH
GRNG	-	GENERATION REQUIREMENTS FROM NATURAL GAS PLANT:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENT FROM PLANT D:MWH
GRPLNTE	-	GENERATION REQUIREMENT FROM PLANT E:MWH
GRPLNTF	-	GENERATION REQUIREMENT FROM PLANT F:MWH
GRPLNTG	-	GENERATION REQUIREMENT FROM PLANT G:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPCPL	-	INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
IAPINST	-	INSTRUMENT FOR IAPCPL
ISCPL	-	INDUSTRIAL SALES:MWH
OAPCPL	-	OTHER AVERAGE PRICE:000'S OF $ PER MWH
OAPINST	-	INSTRUMENT FOR OAPCPL
OSCPL	-	OTHER SALES:MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE
PLNTEC	-	CONDITIONAL VARIABLE
PLNTFC	-	CONDITIONAL VARIABLE

PLNTGC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RAPCPL	-	RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
RAPINST	-	INSTRUMENT FOR RAPCPL
RSCPL	-	RESIDENTIAL SALES:MWH
TSCPL	-	TOTAL SYSTEM SALES:MWH
VCECPL	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE:000'S OF $
VCNG	-	NATURAL GAS COST:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B:000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANT C:000'S OF $
VCPLNTD	-	VARIABLE COST FOR PLANT D:000'S OF $
VCPLNTE	-	VARIABLE COST FOR PLANT E:000'S OF $
VCPLNTF	-	VARIABLE COST FOR PLANT F:000'S OF $
VCPLNTG	-	VARIABLE COST FOR PLANT G:000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $
VCRCPL	-	TOTAL FUEL EXPENSE AND PURCAHSED POWER COST REPORTED:000'S OF $
WAPCPL	-	WHOLESALE AVERAGE PRICE:000'S OF $ PER MWH
WAPINST	-	INSTRUMENT FOR WAPCPL
WSCPL	-	WHOLESALE SALES:MWH

EXOGENOUS:

CCCPL	-	COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CDDCPL	-	COOLING DEGREE DAYS:NUMBER OF DAYS
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLNTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLNTC	-	GENERATION CAPABILITY OF PLANT C:MWH
GCPLNTD	-	GENERATION CAPABILITY OF PLANT D:MWH
GCPLNTE	-	GENERATION CAPABILITY OF PLANT E:MWH
GCPLNTF	-	GENERATION CAPABILITY OF PLANT F:MWH
GCPLNTG	-	GENERATION CAPABILITY OF PLANT G:MWH

GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
HDDCPL	-	HEATING DEGREE DAYS:NUMBER OF DAYS
ILFCSCPL	-	LOSS FACTOR:COMMERCIAL SALES
ILFISCPL	-	LOSS FACTOR:INDUSTRIAL SALES
ILFOSCPL	-	LOSS FACTOR:OTHER SALES
ILFRSCPL	-	LOSS FACTOR:RESIDENTIAL SALES
ILFWSCPL	-	LOSS FACTOR:WHOLESALE SALES
ISDUM	-	DUMMY FOR INDUSTRIAL SALES
MATFCCPL	-	FOUR QUARTER MOVING SUM OF FIXED COSTS: 000'S OF $
NAGCPL	-	NON-AGRICULTURAL EMPLOYMENT: 000'S OF PERSONS
PNGICPL	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS: $ PER MCF
POPCPL	-	POPULATION DATA:000'S OF PERSONS
Q2	-	SECOND QUARTER DUMMY VARIABLE
RCCPL	-	RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPICPL	-	REAL PERSONAL INCOME:BILLIONS OF $
UFCNG	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN NATURAL GAS PLANT:000'S OF $
UFCPLNTA	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT A:000'S OF $
UFCPLNTB	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT B:000'S OF $
UFCPLNTC	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT C:000'S OF $
UFCPLNTD	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT D:000'S OF $
UFCPLNTE	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANTE:000'S OF $
UFCPLNTF	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT F:000'S OF $
UFCPLNTG	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT G:000'S OF $
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $
WSDUM1	-	WHOLESALE SALES DUMMY # 1
WSDUM2	-	WHOLESALE SALES DUMMY # 2

IDENTITIES

```
RAPINST=(RAPCPL(-4)/CPITX(-4))*RCCPL;
CAPINST=(CAPCPL/CPITX)*CCCPL;
IAPINST=IAPCPL/PNGICPL;
OAPINST=OAPCPL(-1)/CPITX(-1);
WAPINST=WAPCPL/CPITX;

TSCPL=RSCPL+CSCPL+ISCPL+OSCPL+WSCPL;

AFCCPL=MATFCCPL/
 (TSCPL+TSCPL(-1)+TSCPL(-2)+TSCPL(-3));

AVCRCPL=VCRCPL/TSCPL;

GENRCPL = RSCPL * ILFRSCPL + CSCPL * ILFCSCPL +
 ISCPL* ILFISCPL + OSCPL*ILFOSCPL + WSCPL*ILFWSCPL;

PPCC = GENRCPL-GCPPC;
PLNTAC = PPCC-GCPLNTA;
PLNTBC = PLNTAC-GCPLNTB;
PLNTCC = PLNTBC-GCPLNTC;
PLNTDC = PLNTCC-GCPLNTD;
PLNTEC = PLNTDC-GCPLNTE;
PLNTFC = PLNTEC-GCPLNTF;
PLNTGC = PLNTFC-GCPLNTG;

GRPPC = (PPCC>0)*GCPPC+(PPCC<0)*GENRCPL;
VCPPC = GRPPC*UFCPPC/1000;
GRPLNTA = (PPCC>0)*( (PLNTAC>0)*GCPLNTA+(PLNTAC<=0)*PPCC);
VCPLNTA = GRPLNTA*UFCPLNTA/1000;
GRPLNTB = (PPCC>0)*(PLNTAC>0)*( (PLNTBC>0)*GCPLNTB+
 (PLNTBC<=0)*PLNTAC );
VCPLNTB = GRPLNTB*UFCPLNTB/1000;
GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*( (PLNTCC>0)*GCPLNTC+
 (PLNTCC<=0)*PLNTBC );
VCPLNTC = GRPLNTC*UFCPLNTC/1000;
GRPLNTD = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 ( (PLNTDC>0)*GCPLNTD+(PLNTDC<=0)*PLNTCC );
VCPLNTD = GRPLNTD*UFCPLNTD/1000;
GRPLNTE = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
 ( (PLNTEC>0)*GCPLNTE+(PLNTEC<=0)*PLNTDC );
VCPLNTE = GRPLNTE*UFCPLNTE/1000;
GRPLNTF = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 ( (PLNTFC>0)*GCPLNTF+(PLNTFC<=0)*PLNTEC );
VCPLNTF = GRPLNTF*UFCPLNTF/1000;
GRPLNTG = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
 (PLNTFC>0)*( (PLNTGC>0)*GCPLNTG+(PLNTGC<=0)*PLNTFC );
VCPLNTG = GRPLNTG*UFCPLNTG/1000;
GRNG = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*
```

(PLNTFC>0)*(PLNTGC>0)*PLNTGC ;
VCNG = GRNG*UFCNG/1000;

VCECPL =
VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+
VCPLNTE+VCPLNTF+VCPLNTG+VCNG+VCPPC;

EQUATION ESTIMATES

EQUATION 1: RESIDENTIAL SALES

RSCPL=a0+a1*RSCPL(-1)+a2*RAPINST+a3*RPICPL+a4*RCDDINST+a5*RHDDINST

Number of observations: 54
(Statistics based on transformed data)
Mean of dependent variable = .213485E+07
Std. dev. of dependent var. = 453174.
Sum of squared residuals = .122142E+12
Variance of residuals = .254463E+10
Std. error of regression = 50444.3
R-squared = .988778
Adjusted R-squared = .987609
Durbin-Watson statistic = 1.44024
Rho (autocorrelation coef.) = -.959125
Standard error of rho = .038509
t-statistic for rho = -24.9065
Log of likelihood function = -658.188
(Statistics based on original data)
Mean of dependent variable = .109479E+07
Std. dev. of dependent var. = 296694.
Sum of squared residuals = .122142E+12
Variance of residuals = .254463E+10
Std. error of regression = 50444.3
R-squared = .973832
Adjusted R-squared = .971106
Durbin-Watson statistic = 1.44024

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-246110.	77829.9	-3.16215
RSCPL(-1)	.553401	.031920	17.3371
RAPINST	-2.91186	1.94852	-1.49440
RPICPL	97385.7	30627.8	3.17965
RCDDINST	.119137E-02	.681325E-04	17.4862
RHDDINST	.757458E-03	.174820E-03	4.33279

EQUATION 2: COMMERCIAL SALES

CSCPL=b0+b1*CSCPL(-1)+b2*CAPINST*b3*NAGCPL+b4*CCDDINST+b5*CHDDINST

Number of observations: 55

(Statistics based on transformed data)
Mean of dependent variable = 607458.
Std. dev. of dependent var. = 135894.
Sum of squared residuals = .245554E+11
Variance of residuals = .501130E+09
Std. error of regression = 22385.9
R-squared = .975376
Adjusted R-squared = .972864
Durbin-Watson statistic = 2.15096
Rho (autocorrelation coef.) = .310786
Standard error of rho = .128163
t-statistic for rho = 2.42493
Log of likelihood function = -625.755
(Statistics based on original data)
Mean of dependent variable = 877586.
Std. dev. of dependent var. = 160944.
Sum of squared residuals = .245554E+11
Variance of residuals = .501130E+09
Std. error of regression = 22385.9
R-squared = .982457
Adjusted R-squared = .980667
Durbin-Watson statistic = 2.15096

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-195413.	80682.5	-2.42201
CSCPL(-1)	.583833	.031397	18.5954
CAPINST	-28.5002	11.6747	-2.44120
NAGCPL	843.789	209.606	4.02560
CCDDINST	.375484E-02	.153632E-03	24.4405
CHDDINST	.220387E-02	.355801E-03	6.19410

EQUATION 3: INDUSTRIAL SALES

ISCPL=c0+c1*ISCPL(-1)+c2*POPCPL+c3*IAPINST+c4*ISDUM+c5*CDDCPL

Number of observations: 48
Mean of dependent variable = .132461E+07
Std. dev. of dependent var. = 181564.
Sum of squared residuals = .315823E+12
Variance of residuals = .751960E+10
Std. error of regression = 86715.6
R-squared = .797984
Adjusted R-squared = .773935
Durbin-Watson statistic = 2.31282
F-statistic (zero slopes) = 32.8092
E'PZ*E = .117896E+12

Variable	Estimated Coefficient	Standard Error	t-statistic
C	399072.	283782.	1.40626
ISCPL(-1)	.668747	.126135	5.30183
POPCPL	186.255	182.702	1.01944

IAPINST	-.224343E+08	.174842E+08	-1.28312
ISDUM	-83203.5	57053.0	-1.45835
CDDCPL	64.6621	21.7071	2.97885

EQUATION 4: OTHER RETAIL SALES

OSCPL=d0+d1*OSCPL(-1)+d2*POPCPL+d3*OAPINST+d4*CDDCPL+d5*HDDCPL

Number of observations: 55
(Statistics based on transformed data)
Mean of dependent variable = 175609.
Std. dev. of dependent var. = 31692.7
Sum of squared residuals = .357413E+10
Variance of residuals = .729415E+08
Std. error of regression = 8540.58
R-squared = .934104
Adjusted R-squared = .927380
Durbin-Watson statistic = 1.91387
Rho (autocorrelation coef.) = -.492020
Standard error of rho = .117390
t-statistic for rho = -4.19134
Log of likelihood function = -572.757
(Statistics based on original data)
Mean of dependent variable = 117999.
Std. dev. of dependent var. = 27233.5
Sum of squared residuals = .357413E+10
Variance of residuals = .729415E+08
Std. error of regression = 8540.58
R-squared = .910762
Adjusted R-squared = .901656
Durbin-Watson statistic = 1.91387

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-43955.7	16380.6	-2.68339
OSCPL(-1)	.370037	.045760	8.08641
POPCPL	45.1403	7.12240	6.33780
OAPINST	-196398.	139116.	-1.41176
CDDCPL	51.4632	5.23703	9.82678
HDDCPL	25.5287	13.0952	1.94947

EQUATION 5: WHOLESALE SALES

**WSCPL=c0+c1*WAPINST+c2*NAGCPL+c3*WSDUM1+c4*WSDUM2+
c5*CDDCPL+c6*HDDCPL**

Number of observations: 57
Mean of dependent variable = 114578.
Std. dev. of dependent var. = 45974.6
Sum of squared residuals = .735401E+10
Variance of residuals = .147080E+09
Std. error of regression = 12127.7
R-squared = .937880
Adjusted R-squared = .930426
Durbin-Watson statistic = 1.85511

F-statistic (zero slopes) = 125.795
E'PZ*E = .294055E+10

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-2377.65	38563.6	-.061655
WAPINST	-.274665E+07	318659.	-8.61940
NAGCPL	341.748	64.1346	5.32861
WSDUM1	130734.	6321.06	20.6823
WSDUM2	80600.4	9427.22	8.54976
CDDCPL	25.8754	5.98233	4.32530
HDDCPL	45.1178	13.7234	3.28766

EQUATION 6: RESIDENTIAL AVERAGE PRICE

RAPCPL=f0+f1*AVCRCPL+f2*AFCCPL

Number of observations: 48
Mean of dependent variable = .066654
Std. dev. of dependent var. = .830518E-02
Sum of squared residuals = .853334E-03
Variance of residuals = .189630E-04
Std. error of regression = .435465E-02
R-squared = .737706
Adjusted R-squared = .726048
Durbin-Watson statistic = 1.49883
F-statistic (zero slopes) = 62.9790
E'PZ*E = .502537E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.137510E-02	.592157E-02	.232218
AVCRCPL	1.10747	.112990	9.80145
AFCCPL	1.00005	.094265	10.6089

EQUATION 7: COMMERCIAL AVERAGE PRICE

CAPCPL=g0+g1*AVCRCPL+g2*AFCCPL

Number of observations: 46
(Statistics based on transformed data)
Mean of dependent variable = .046580
Std. dev. of dependent var. = .558794E-02
Sum of squared residuals = .546682E-03
Variance of residuals = .127135E-04
Std. error of regression = .356560E-02
R-squared = .612912
Adjusted R-squared = .594908
Durbin-Watson statistic = 1.86667
Rho (autocorrelation coef.) = .337152
Standard error of rho = .138809
t-statistic for rho = 2.42889
Log of likelihood function = 195.555
(Statistics based on original data)

Mean of dependent variable = .070009
Std. dev. of dependent var. = .735770E-02
Sum of squared residuals = .546682E-03
Variance of residuals = .127135E-04
Std. error of regression = .356560E-02
R-squared = .775592
Adjusted R-squared = .765155
Durbin-Watson statistic = 1.86667

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.875017E-02	.773574E-02	1.13114
AVCRCPL	1.01678	.139038	7.31297
AFCCPL	.940081	.125487	7.49143

EQUATION 8: INDUSTRIAL AVERAGE PRICE

IAPCPL=h0+h1*AVCRCPL+h2*AFCCPL

Number of observations: 48
Mean of dependent variable = .047270
Std. dev. of dependent var. = .691267E-02
Sum of squared residuals = .606285E-03
Variance of residuals = .134730E-04
Std. error of regression = .367056E-02
R-squared = .731524
Adjusted R-squared = .719592
Durbin-Watson statistic = 1.03993
F-statistic (zero slopes) = 60.8480
E'PZ*E = .496311E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.010025	.499132E-02	2.00853
AVCRCPL	.951063	.095240	9.98594
AFCCPL	.258916	.079457	3.25858

EQUATION 9: OTHER RETAIL AVERAGE PRICE

OAPCPL=i0+i1*AVCRCPL+i2*AFCCPL

Number of observations: 46
(Statistics based on transformed data)
Mean of dependent variable = .051054
Std. dev. of dependent var. = .583791E-02
Sum of squared residuals = .619761E-03
Variance of residuals = .144131E-04
Std. error of regression = .379645E-02
R-squared = .597931
Adjusted R-squared = .579230
Durbin-Watson statistic = 1.87762
Rho (autocorrelation coef.) = .249805
Standard error of rho = .142767
t-statistic for rho = 1.74973

Log of likelihood function = 192.670
(Statistics based on original data)
Mean of dependent variable = .067861
Std. dev. of dependent var. = .715533E-02
Sum of squared residuals = .619761E-03
Variance of residuals = .144131E-04
Std. error of regression = .379645E-02
R-squared = .731028
Adjusted R-squared = .718518
Durbin-Watson statistic = 1.87762

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.955678E-02	.748640E-02	1.27655
AVCRCPL	.964751	.135115	7.14024
AFCCPL	.898558	.120709	7.44398

EQUATION 10: WHOLESALE AVERAGE PRICE

WAPCPL=j0+j1*AVCRCPL+j2*AFCCPL

Number of observations: 46
(Statistics based on transformed data)
Mean of dependent variable = .026188
Std. dev. of dependent var. = .436642E-02
Sum of squared residuals = .622656E-03
Variance of residuals = .144804E-04
Std. error of regression = .380531E-02
R-squared = .277545
Adjusted R-squared = .243942
Durbin-Watson statistic = 1.95972
Rho (autocorrelation coef.) = .400730
Standard error of rho = .135086
t-statistic for rho = 2.96649
Log of likelihood function = 192.562
(Statistics based on original data)
Mean of dependent variable = .043684
Std. dev. of dependent var. = .592949E-02
Sum of squared residuals = .622656E-03
Variance of residuals = .144804E-04
Std. error of regression = .380531E-02
R-squared = .606633
Adjusted R-squared = .588336
Durbin-Watson statistic = 1.95972

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.019905	.888736E-02	2.23972
AVCRCPL	.585498	.159072	3.68072
AFCCPL	.182209	.145066	1.25603

EQUATION 11: TOTAL FUEL EXPENSE AND PURCHASED POWER COST

VCRCPL=k0+k1*VCECPL+k2*Q2

Number of observations: 48
Mean of dependent variable = 105026.
Std. dev. of dependent var. = 27257.0
Sum of squared residuals = .270478E+10
Variance of residuals = .601062E+08
Std. error of regression = 7752.82
R-squared = .922556
Adjusted R-squared = .919114
Durbin-Watson statistic = 1.94453
F-statistic (zero slopes) = 267.973
E'PZ*E = .136414E+10

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-1509.77	4783.24	-.315638
VCECPL	1.01544	.044101	23.0252
Q2	10337.3	2609.63	3.96124

4-5 CITY PUBLIC SERVICE OF SAN ANTONIO

MODEL: CPS

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCCPS	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRCPS	-	AVERAGE FUEL AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CAPCPS	-	COMMERCIAL AVERAGE PRICE :000'S OF $ PER MWH
CSCPS	-	COMMERCIAL SALES:MWH
GENRCPS	-	GENERATION REQUIREMENTS:MWH
GRNG	-	GENERATION REQUIREMENTS FROM NATURAL GAS PLANT:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENT FROM PLANT D:MWH
GRPLNTE	-	GENERATION REQUIREMENT FROM PLANT E:MWH
GRPLNTF	-	GENERATION REQUIREMENT FROM PLANT F:MWH
GRPLNTG	-	GENERATION REQUIREMENT FROM PLANT G:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPCPS	-	INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE
PLNTEC	-	CONDITIONAL VARIABLE
PLNTFC	-	CONDITIONAL VARIABLE
PLNTGC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
OAPCPS	-	OTHER RETAIL AVERAGE PRICE: 000'S OF $ PER MWH
RAPCPS	-	RESIDENTIAL AVERAGE PRICE:000'S OF PER MWH
RSCPS	-	RESIDENTIAL SALES:MWH
TSCPS	-	TOTAL SYSTEM SALES:MWH

VCECPS	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE:000'S OF $
VCNG	-	NATURAL GAS COST:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B:000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANT C:000'S OF $
VCPLNTD	-	VARIABLE COST FOR PLANT D:000'S OF $
VCPLNTE	-	VARIABLE COST FOR PLANT E:000'S OF $
VCPLNTF	-	VARIABLE COST FOR PLANT F:000'S OF $
VCPLNTG	-	VARIABLE COST FOR PLANT G:000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $
VCRCPS	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST REPORTED:000'S OF $

EXOGENOUS:

CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
GCPLANTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLANTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLANTC	-	GENERATION CAPABILITYOF PLANT C:MWH
GCPLANTD	-	GENERATION CAPABILITY OF PLANT D:MWH
GCPLANTE	-	GENERATION CAPABILITY OF PLANT E:MWH
GCPLANTF	-	GENERATION CAPABILITY OF PLANT F:MWH
GCPLANTG	-	GENERATION CAPABILITY OF PLANT G:MWH
GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
ISCPS	-	INDUSTRIAL SALES:MWH
LFCPS	-	SYSTEM LOSS FACTOR
MATFCCPS	-	FOUR QUARTER MOVING SUM TOTAL FIXED COSTS: 000'S OF $
OSCPS	-	OTHER RETAIL SALES: MWH
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPICPS	-	REAL PERSONAL INCOME (BILLIONS OF $)
UFCNG	-	FUEL COST TO PRODUCE ON MWH OF ELECTRICITY IN NATURAL GAS PLANTS:000'S OF $

UFCPLANTA - VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT A:000'S OF $ PER MWH

UFCPLANTB - VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT B:000'S OF $ PER MWH

UFCPLANTC - VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT C:000'S OF $ PER MWH

UFCPLANTD - VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT D:000'S OF $ PER MWH

UFCPLANTE - VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT E:000'S OF $ PER MWH

UFCPLANTF - VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT F:000'S OF $ PER MWH

UFCPLANTG - VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT G:000'S OF $ PER MWH

UFCPPC - UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH

IDENTITIES:

```
TSCPS=RSCPS+CSCPS+ISCPS+OSCPS

AFCCPS=MATFCCPS/
 (TSCPS+TSCPS(-1)+TSCPS(-2)+TSCPS(-3));

AVCRCPS=VCRCPS/TSCPS;

GENRCPS = TSCPS/(1-LFCPS);

PPCC = GENRCPS-GCPPC;
PLNTAC = PPCC-GCPLNTA;
PLNTBC = PLNTAC-GCPLNTB;
PLNTCC = PLNTBC-GCPLNTC;
PLNTDC = PLNTCC-GCPLNTD;
PLNTEC = PLNTDC-GCPLNTE;
PLNTFC = PLNTEC-GCPLNTF;
PLNTGC = PLNTFC-GCPLNTG;

GRPPC = (PPCC>0)*GCPPC+(PPCC<0)*GENRCPS;
VCPPC = GRPPC*UFCPPC/1000;
GRPLNTA = (PPCC>0)*( (PLNTAC>0)*GCPLNTA+(PLNTAC<=0)*PPCC);
VCPLNTA = GRPLNTA*UFCPLNTA/1000;
GRPLNTB = (PPCC>0)*(PLNTAC>0)*( (PLNTBC>0)*GCPLNTB+
 (PLNTBC<=0)*PLNTAC );
VCPLNTB = GRPLNTB*UFCPLNTB/1000;
GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*( (PLNTCC>0)*GCPLNTC+
 (PLNTCC<=0)*PLNTBC );
VCPLNTC = GRPLNTC*UFCPLNTC/1000;
GRPLNTD = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 ( (PLNTDC>0)*GCPLNTD+(PLNTDC<=0)*PLNTCC );
VCPLNTD = GRPLNTD*UFCPLNTD/1000;
```

```
GRPLNTE = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 (PLNTDC>0)*( (PLNTEC>0)*GCPLNTE+(PLNTEC<=0)*PLNTDC );
VCPLNTE = GRPLNTE*UFCPLNTE/1000;
GRPLNTF = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 (PLNTDC>0)*(PLNTEC>0)*
 ( (PLNTFC>0)*GCPLNTF+(PLNTFC<=0)*PLNTEC );
VCPLNTF = GRPLNTF*UFCPLNTF/1000;
GRPLNTG = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 (PLNTDC>0)*(PLNTEC>0)*(PLNTFC>0)*
 ( (PLNTGC>0)*GCPLNTG+(PLNTGC<=0)*PLNTFC );
VCPLNTG = GRPLNTG*UFCPLNTG/1000;
GRNG = (PPCC>0)*
 (PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
 (PLNTEC>0)*(PLNTFC>0)*(PLNTGC>0)*PLNTGC ;
VCNG = GRNG*UFCNG/1000;

VCECPS =
 VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+VCPLNTE+
 VCPLNTF+VCPLNTG+VCNG+VCPPC;
```

EQUATION ESTIMATES

EQUATION 1: RESIDENTIAL SALES

RSCPS=a0+a1*RSCPS(-4)+a2*RPICPS(-4)+a3*RCDDINST+a4*RHDDINST

Number of observations: 52
Mean of dependent variable = 929032.
Std. dev. of dependent var. = 353303.
Sum of squared residuals = .108214E+12
Variance of residuals = .230243E+10
Std. error of regression = 47983.7
R-squared = .983001
Adjusted R-squared = .981554
Durbin-Watson statistic = 1.71604
Durbin's h alternative = .849967
F-statistic (zero slopes) = 679.473
Schwarz Bayes. Info. Crit. = 21.8361
Log of likelihood function = -631.644

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-112736.	60892.2	-1.85140
RSCPS(-4)	.687186	.063722	10.7841
RPICPS(-4)	59465.2	29048.6	2.04710
RCDDINST	.685445E-03	.123324E-03	5.55807
RHDDINST	.563109E-03	.125438E-03	4.48916

EQUATION 2: COMMERCIAL SALES

CSCPS=b0+b1*RPICPS(-4)+b2*CCDDINST+b3*CHDDINST

Number of observations: 49
(Statistics based on transformed data)
Mean of dependent variable = 260330.
Std. dev. of dependent var. = 95347.1
Sum of squared residuals = .337419E+11
Variance of residuals = .749819E+09
Std. error of regression = 27382.8
R-squared = .922901
Adjusted R-squared = .917762
Durbin-Watson statistic = 1.97009
Rho (autocorrelation coef.) = .468691
Standard error of rho = .131505
t-statistic for rho = 3.56406
F-statistic (zero slopes) = 178.989
Log of likelihood function = -568.232
(Statistics based on original data)
Mean of dependent variable = 481161.
Std. dev. of dependent var. = 126762.
Sum of squared residuals = .340858E+11
Variance of residuals = .757462E+09
Std. error of regression = 27522.0
R-squared = .956368
Adjusted R-squared = .953459
Durbin-Watson statistic = 1.95176

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-274499.	54417.7	-5.04430
RPICPS(-4)	226939.	20742.4	10.9408
CCDDINST	.351861E-02	.252511E-03	13.9345
CHDDINST	.201386E-02	.414974E-03	4.85298

EQUATION 3: RESIDENTIAL AVERAGE PRICE

RAPCPS=c0+c1*AVCRCPS+c2*AFCCPS

Number of observations: 57
Mean of dependent variable = .061895
Std. dev. of dependent var. = .010368
Sum of squared residuals = .661220E-03
Variance of residuals = .122448E-04
Std. error of regression = .349926E-02
R-squared = .890503
Adjusted R-squared = .886447
Durbin-Watson statistic = 1.77778
F-statistic (zero slopes) = 218.827
E'PZ*E = .406810E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.983958E-02	.259973E-02	3.78485
AVCRCPS	.974069	.068512	14.2176
AFCCPS	.990297	.051594	19.1942

EQUATION 4: COMMERCIAL AVERAGE PRICE

CAPCPS=d0+d1*AVCRCPS+d2*AFCCPS

Number of observations: 55
(Statistics based on transformed data)
Mean of dependent variable = .036896
Std. dev. of dependent var. = .576920E-02
Sum of squared residuals = .388337E-03
Variance of residuals = .746802E-05
Std. error of regression = .273277E-02
R-squared = .784109
Adjusted R-squared = .775806
Durbin-Watson statistic = 2.00131
Rho (autocorrelation coef.) = .388432
Standard error of rho = .124252
t-statistic for rho = 3.12617
Log of likelihood function = 248.135
(Statistics based on original data)
Mean of dependent variable = .060152
Std. dev. of dependent var. = .868525E-02
Sum of squared residuals = .388337E-03
Variance of residuals = .746802E-05
Std. error of regression = .273277E-02
R-squared = .904837
Adjusted R-squared = .901176
Durbin-Watson statistic = 2.00131

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.016259	.347108E-02	4.68401
AVCRCPS	.888067	.083112	10.6852
AFCCPS	.769519	.070294	10.9472

EQUATION 5: INDUSTRIAL AVERAGE PRICE

IAPCPS=c0+c1*AVCRCPS+c2*AFCCPS

Number of observations: 57
Mean of dependent variable = .046605
Std. dev. of dependent var. = .944365E-02
Sum of squared residuals = .451384E-03
Variance of residuals = .835897E-05
Std. error of regression = .289119E-02
R-squared = .909630
Adjusted R-squared = .906283
Durbin-Watson statistic = 1.76558
F-statistic (zero slopes) = 271.734
E'PZ*E = .215116E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.111247E-02	.214797E-02	-.517915
AVCRCPS	1.01921	.056606	18.0052
AFCCPS	.816773	.042628	19.1604

EQUATION 6: OTHER RETAIL AVERAGE PRICE

OAPCPS=f0+f1*AVCRCPS+f2*AFCCPS

Number of observations: 46
(Statistics based on transformed data)
Mean of dependent variable = .014946
Std. dev. of dependent var. = .339022E-02
Sum of squared residuals = .320268E-03
Variance of residuals = .744808E-05
Std. error of regression = .272912E-02
R-squared = .382213
Adjusted R-squared = .353479
Durbin-Watson statistic = 2.00284
Rho (autocorrelation coef.) = .762484
Standard error of rho = .095396
t-statistic for rho = 7.99282
Log of likelihood function = 207.854
(Statistics based on original data)
Mean of dependent variable = .062357
Std. dev. of dependent var. = .681351E-02
Sum of squared residuals = .320268E-03
Variance of residuals = .744808E-05
Std. error of regression = .272912E-02
R-squared = .849484
Adjusted R-squared = .842484
Durbin-Watson statistic = 2.00284

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.041083	.932627E-02	4.40505
AVCRCPS	.494245	.116491	4.24277
AFCCPS	.312027	.225720	1.38236

EQUATION 7: TOTAL FUEL EXPENSE AND PRUCHASED POWER COST

VCRCPS=g0+g1*VCECPS

Number of observations: 57
Mean of dependent variable = 49167.3
Std. dev. of dependent var. = 19641.7
Sum of squared residuals = .190361E+10
Variance of residuals = .346111E+08
Std. error of regression = 5883.12
R-squared = .912766
Adjusted R-squared = .911180
Durbin-Watson statistic = 2.15983

F-statistic (zero slopes) = 569.213
E'PZ*E = .549781E+09

Variable	Estimated Coefficient	Standard Error	t-statistic
C	464.123	2228.94	.208226
VCECPS	1.01384	.043472	23.3220

4-6 SOUTHWESTERN PUBLIC SERVICE COMPANY

MODEL: SPS

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCSPS	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRSPS	-	AVERAGE FUEL EXPENSES AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CAPINSN	-	INSTRUMENT FOR CAPSPSN
CAPINST	-	INSTRUMENT FOR CAPSPST
CAPSPSN	-	COMMERCIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
CAPSPST	-	COMMERCIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
CSSPSN	-	COMMERCIAL SALES (NON-TEXAS):MWH
CSSPST	-	COMMERCIAL SALES (TEXAS):MWH
GENRSPS	-	GENERATION REQUIREMENTS:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENT FROM PLANT D:MWH
GRPLNTE	-	GENERATION REQUIREMENT FROM PLANT E:MWH
GRPLNTF	-	GENERATION REQUIREMENT FROM PLANT F: MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPINSN	-	INSTRUMENT FOR IAPSPSN
IAPINST	-	INSTRUMENT FOR IAPSPST
IAPSPSN	-	INDUSTRIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
IAPSPST	-	INDUSTRIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
ISSPSN	-	INDUSTRIAL SALES (NON-TEXAS):MWH
ISSPST	-	INDUSTRIAL SALES (TEXAS):MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE
PLNTEC	-	CONDITIONAL VARIABLE

PPCC	-	CONDITIONAL VARIABLE
RAPINSN	-	INSTRUMENT FOR RAPSPSN
RAPINST	-	INSTRUMENT FOR RAPSPST
RAPSPSN	-	RESIDENTIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
RAPSPST	-	RESIDENTIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
RSSPSN	-	RESIDENTIAL SALES (NON-TEXAS):MWH
RSSPST	-	RESIDENTIAL SALES (TEXAS):MWH
TCSPS	-	TOTAL COSTS: 000'S OF $
TFCSPS	-	TOTAL FIXED COSTS:000'S OF $
TSSPS	-	TOTAL SYSTEM SALES:MWH
TSSPSN	-	TOTAL NON-TEXAS SYSTEM SALES:MWH
TSSPST	-	TOTAL TEXAS SYSTEM SALES:MWH
VCESPS	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B:000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANT C:000'S OF $
VCPLNTD	-	VARIABLE COST FOR PLANT D:000'S OF $
VCPLNTE	-	VARIABLE COST FOR PLANT E:000'S OF $
VCPLNTF	-	VARIABLE COST FOR PLANT F:000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $
VCRSPS	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST REPORTED:000'S OF $
WAPINSN	-	INSTRUMENT FOR WAPSPSN
WAPSPSN	-	WHOLESALE AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
WSSPSN	-	WHOLESALE SALES (NON-TEXAS): MWH

EXOGENOUS:

APTDUM1	-	TEXAS AVERAGE PRICE DUMMY VARIABLE
APTDUM2	-	TEXAS AVERAGE PRICE DUMMY VARIABLE
APTDUM3	-	TEXAS AVERAGE PRICE DUMMY VARIABLE
APTDUM4	-	TEXAS AVERAGE PRICE DUMMY VARIABLE
CCDDINSN	-	INSTRUMENT FOR (NON-TEXAS) COMMERCIAL COOLING DEGREE DAYS
CCDDINST	-	INSTRUMENT FOR (TEXAS) COMMERCIAL COOLING DEGREE DAYS

CCSPSN	-	COMMERCIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
CCSPST	-	COMMERCIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
CDDSPS	-	COOLING DEGREE DAYS:NUMBER OF DAYS
CHDDINSN	-	INSTRUMENT FOR (NON-TEXAS) COMMERCIAL HEATING DEGREE DAYS
CHDDINST	-	INSTRUMENT FOR (TEXAS) COMMERCIAL HEATING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
GCPLANTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLANTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLANTC	-	GENERATION CAPABILITY OF PLANT C:MWH
GCPLANTD	-	GENERATION CAPABILITY OF PLANT D:MWH
GCPLANTE	-	GENERATION CAPABILITY OF PLANT E: MWH
GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
ILFCSSPS	-	LOSS FACTOR:COMMERCIAL SALES
ILFISSPS	-	LOSS FACTOR:INDUSTRIAL SALES
ILFOSSPS	-	LOSS FACTOR:OTHER SALES
ILFRSSPS	-	LOSS FACTOR:RESIDENTIAL SALES
ILFWSSPS	-	LOSS FACTOR:WHOLESALE SALES
ISNDUM	-	DUMMY VARIABLE FOR NON-TEXAS INDUSTRIAL SALES
MATFCSPS	-	MOVING AVERAGE OF FIXED COST:000'S $
NAGSPSN	-	NON-AGRICULTURAL EMPLOYMENT IN NON-TEXAS SPS SERVICE AREA:000'S OF PERSONS
NTXDUM	-	SHIFT DUMMY FOR NON-TEXAS SALES
OSSPSN	-	OTHER NON-TEXAS SALES:MWH
OSSPST	-	OTHER TEXAS SALES:MWH
RCDDINSN	-	INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL COOLING DEGREE DAYS
RCDDINST	-	INSTRUMENT FOR (TEXAS) RESIDENTIAL COOLING DEGREE DAYS
RCSPSN	-	RESIDENTIAL CUSTOMER (NON-TEXAS):NUMBER OF CUSTOMERS
RCSPST	-	RESIDENTIAL CUSTOMER (TEXAS):NUMBER OF CUSTOMERS
RHDDINSN	-	INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL HEATING DEGREE DAYS
RHDDINST	-	INSTRUMENT FOR (TEXAS) RESIDENTIAL HEATING DEGREE DAYS
TIME	-	TIME TREND VARIABLE

UFCPLANTA	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT A:000'S OF $ PER MWH
UFCPLANTB	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT B:000'S OF $ PER MWH
UFCPLANTC	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT C:000'S OF $ PER MWH
UFCPLANTD	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT D:000'S OF $ PER MWH
UFCPLANTE	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT E:000'S OF $ PER MWH
UFCPLANTF	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT F:000'S OF $ PER MWH
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH
VCRDUM	-	TOTAL FUEL EXPENSE DUMMY VARIABLE
WAPNDUM	-	NON-TEXAS WHOLESALE AVERAGE PRICE DUMMY VARIABLE
WSSPST	-	WHOLESALE TEXAS SALES:MWH

IDENTITIES

```
RAPINST=(RAPSPST/CPITX)*RCSPST;
RAPINSN=(RAPSPSN/CPITX)*RCSPSN;
CAPINST=(CAPSPST/CPITX)*CCSPST;
CAPINSN=(CAPSPSN/CPITX)*CCSPSN;
IAPINST=(IAPSPST/CPITX);
IAPINSN=(IAPSPSN/CPITX);
WAPINSN=WAPSPSN/CPITX;

TSSPST=RSSPST+CSSPST+ISSPST+OSSPST+WSSPST;
TSSPSN=RSSPSN+CSSPSN+ISSPSN+OSSPSN+WSSPSN;
TSSPS=TSSPST+TSSPSN;

AFCSPS=MATFCSPS/
 (TSSPS+TSSPS(-1)+TSSPS(-2)+TSSPS(-3));

AVCRSPS=VCRSPS/TSSPS;

GENRSPS = (RSSPST+RSSPSN) * ILFRSSPS +
 (CSSPST+CSSPSN) * ILFCSSPS +
 (ISSPST+ISSPSN) * ILFISSPS +
 (OSSPST+OSSPSN) * ILFOSSPS +
 (WSSPST+WSSPSN) * ILFWSSPS;

PPCC = GENRSPS-GCPPC;
PLNTAC = PPCC-GCPLNTA;
PLNTBC = PLNTAC-GCPLNTB;
PLNTCC = PLNTBC-GCPLNTC;
PLNTDC = PLNTCC-GCPLNTD;
PLNTEC = PLNTDC-GCPLNTE;
```

```
GRPPC = (PPCC>0)*GCPPC+(PPCC<0)*GENRSPS;
VCPPC = GRPPC*UFCPPC/1000;
GRPLNTA = (PPCC>0)*( (PLNTAC>0)*GCPLNTA+(PLNTAC<=0)*PPCC);
VCPLNTA = GRPLNTA*UFCPLNTA/1000;
GRPLNTB = (PPCC>0)*(PLNTAC>0)*( (PLNTBC>0)*GCPLNTB+
 (PLNTBC<=0)*PLNTAC );
VCPLNTB = GRPLNTB*UFCPLNTB/1000;
GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*( (PLNTCC>0)*GCPLNTC+
 (PLNTCC<=0)*PLNTBC );
VCPLNTC = GRPLNTC*UFCPLNTC/1000;
GRPLNTD = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 ( (PLNTDC>0)*GCPLNTD+(PLNTDC<=0)*PLNTCC );
VCPLNTD = GRPLNTD*UFCPLNTD/1000;
GRPLNTE = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
 ( (PLNTEC>0)*GCPLNTE+(PLNTEC<=0)*PLNTDC );
VCPLNTE = GRPLNTE*UFCPLNTE/1000;
GRPLNTF = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 (PLNTDC>0)*(PLNTEC>0)* PLNTEC ;
VCPLNTF = GRPLNTF*UFCPLNTF/1000;

VCESPS =
 VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+
 VCPLNTE+VCPLNTF+VCPPC;
```

EQUATION ESTIMATES

EQUATION 1: TEXAS RESIDENTIAL SALES

RSSPST=a0+a1*RSSPST(-4)+a2*RAPINST+a3*RCDDINST+a4*RHDDINST

Number of observations: 44
Mean of dependent variable = 395192.
Std. dev. of dependent var. = 71489.9
Sum of squared residuals = .592085E+10
Variance of residuals = .151817E+09
Std. error of regression = 12321.4
R-squared = .973080
Adjusted R-squared = .970318
Durbin-Watson statistic = 1.83403
F-statistic (zero slopes) = 352.141
E'PZ*E = .267888E+10

Variable	Estimated Coefficient	Standard Error	t-statistic
C	99080.7	34188.9	2.89804
RSSPST(-4)	.693901	.086573	8.01518
RAPINST	-5.54757	1.98908	-2.78902
RCDDINST	.538973E-03	.135075E-03	3.99019
RHDDINST	.212301E-03	.510076E-04	4.16214

EQUATION 2: NON TEXAS RESIDENTIAL SALES

RSSPSN=b0+b1*RSSPSN(-4)+b2*RAPINSN+b3*NTXDUM+b4*RCDDINSN+b5*RHDDINSN

Number of observations: 42
(Statistics based on transformed data)
Mean of dependent variable = 238907.
Std. dev. of dependent var. = 35157.1
Sum of squared residuals = .912826E+09
Variance of residuals = .253563E+08
Std. error of regression = 5035.50
R-squared = .981988
Adjusted R-squared = .979487
Durbin-Watson statistic = 1.52188
Rho (autocorrelation coef.) = -.633607
Standard error of rho = .119378
t-statistic for rho = -5.30759
Log of likelihood function = -414.378
(Statistics based on original data)
Mean of dependent variable = 146943.
Std. dev. of dependent var. = 26680.9
Sum of squared residuals = .912826E+09
Variance of residuals = .253563E+08
Std. error of regression = 5035.50
R-squared = .968941
Adjusted R-squared = .964627
Durbin-Watson statistic = 1.52188

Variable	Estimated Coefficient	Standard Error	t-statistic
C	84236.4	10048.9	8.38265
RSSPSN(-4)	.201054	.049439	4.06671
RAPINSN	-12.3793	1.74403	-7.09808
NTXDUM	35605.0	3335.88	10.6734
RCDDINSN	.743141E-03	.752700E-04	9.87301
RHDDINSN	.358612E-03	.380701E-04	9.41977

EQUATION 3: TEXAS COMMERCIAL SALES

CSSPST=c0+c1*CSSPST(-4)+c2*CAPINST+c3*CCDDINST+c4*CHDDINST

Number of observations: 31
(Statistics based on transformed data)
Mean of dependent variable = 134312.
Std. dev. of dependent var. = 46433.0
Sum of squared residuals = .171492E+10
Variance of residuals = .659583E+08
Std. error of regression = 8121.47
R-squared = .973507
Adjusted R-squared = .969432
Durbin-Watson statistic = 1.98267
Rho (autocorrelation coef.) = .598305
Standard error of rho = .143912

t-statistic for rho = 4.15743
Log of likelihood function = -320.331
(Statistics based on original data)
Mean of dependent variable = 334177.
Std. dev. of dependent var. = 34748.2
Sum of squared residuals = .171492E+10
Variance of residuals = .659583E+08
Std. error of regression = 8121.47
R-squared = .952809
Adjusted R-squared = .945549
Durbin-Watson statistic = 1.98267

Variable	Estimated Coefficient	Standard Error	t-statistic
C	125690.	31202.0	4.02828
CSSPST(-4)	.630254	.084858	7.42718
CAPINST	-27.6266	13.9680	-1.97785
CCDDINST	.162094E-02	.458748E-03	3.53341
CHDDINST	.497340E-03	.165381E-03	3.00723

EQUATION 4: NON TEXAS COMMERCIAL SALES

CSSPSN=d0+d1*CAPINSN+d2*NTXDUM+d3*CCDDINSN+d4*CHDDINSN

Number of observations: 45
Mean of dependent variable = 107086..
Std. dev. of dependent var. = 20968.8
Sum of squared residuals = .913949E+09
Variance of residuals = .228487E+08
Std. error of regression = 4780.03
R-squared = .952759
Adjusted R-squared = .948034
Durbin-Watson statistic = 1.87809
F-statistic (zero slopes) = 201.679
E'PZ*E = .501510E+09

Variable	Estimated Coefficient	Standard Error	t-statistic
C	69122.8	5928.37	11.6597
CAPINSN	-35.1666	11.7822	-2.98473
NTXDUM	32277.3	2358.94	13.6829
CCDDINSN	.417251E-02	.336117E-03	12.4139
CHDDINSN	.118549E-02	.180951E-03	6.55144

EQUATION 5: TEXAS INDUSTRIAL SALES

ISSPST=c0+c1*TIME+c2*IAPINST+c3*CDDSPS

Number of observations: 42
(Statistics based on transformed data)
Mean of dependent variable = 889288.
Std. dev. of dependent var. = 73693.3
Sum of squared residuals = .352299E+11
Variance of residuals = .927103E+09

Std. error of regression = 30448.4
R-squared = .841917
Adjusted R-squared = .829436
Durbin-Watson statistic = 2.04778
Rho (autocorrelation coef.) = .346974
Standard error of rho = .144717
t-statistic for rho = 2.39760
Log of likelihood function = -491.093
(Statistics based on original data)
Mean of dependent variable = .135775E+07
Std. dev. of dependent var. = 106618.
Sum of squared residuals = .352299E+11
Variance of residuals = .927103E+09
Std. error of regression = 30448.4
R-squared = .924440
Adjusted R-squared = .918475
Durbin-Watson statistic = 2.04778

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.131041E+07	99433.4	13.1788
TIME	6304.77	1134.46	5.55751
IAPINST	-.460280E+07	.234357E+07	-1.96401
CDDSPS	33.5893	9.79618	3.42882

EQUATION 6: NON TEXAS INDUSTRIAL SALES

ISSPSN=f0+f1*ISSPSN(-1)+f2*IAPINSN+f3*NAGSPSN+f4*NTXDUM+f5*ISNDUM+f6*CDDSPS

Number of observations: 44
(Statistics based on transformed data)
Mean of dependent variable = 184600.
Std. dev. of dependent var. = 41916.0
Sum of squared residuals = .537280E+10
Variance of residuals = .145211E+09
Std. error of regression = 12050.3
R-squared = .928887
Adjusted R-squared = .917355
Durbin-Watson statistic = 1.85889
Rho (autocorrelation coef.) = .388190
Standard error of rho = .138933
t-statistic for rho = 2.79407
Log of likelihood function = -472.083
(Statistics based on original data)
Mean of dependent variable = 298553.
Std. dev. of dependent var. = 63260.1
Sum of squared residuals = .537280E+10
Variance of residuals = .145211E+09
Std. error of regression = 12050.3
R-squared = .968777
Adjusted R-squared = .963714
Durbin-Watson statistic = 1.85889

Variable	Estimated Coefficient	Standard Error	t-statistic
C	113817.	86624.9	1.31390
ISSPSN(-1)	.329751	.074588	4.42098
IAPINSN	-.281174E+07	752615.	-3.73596
NAGSPSN	1274.44	957.606	1.33086
NTXDUM	82113.9	11479.9	7.15286
ISNDUM	-65249.2	18078.6	-3.60920
CDDSPS	10.6494	3.86932	2.75226

EQUATION 7: NON TEXAS WHOLESALE SALES

WSSPSN=g0+g1*WSSPSN(-4)+g2*WAPINSN+g3*CDDSPS

Number of observations: 42
(Statistics based on transformed data)
Mean of dependent variable = 46439.9
Std. dev. of dependent var. = 37830.2
Sum of squared residuals = .244654E+11
Variance of residuals = .643827E+09
Std. error of regression = 25373.7
R-squared = .583309
Adjusted R-squared = .550412
Durbin-Watson statistic = 1.86155
Rho (autocorrelation coef.) = .840543
Standard error of rho = .083593
t-statistic for rho = 10.0552
Log of likelihood function = -483.435
(Statistics based on original data)
Mean of dependent variable = 275065.
Std. dev. of dependent var. = 67710.7
Sum of squared residuals = .244654E+11
Variance of residuals = .643827E+09
Std. error of regression = 25373.7
R-squared = .869938
Adjusted R-squared = .859670
Durbin-Watson statistic = 1.86155

Variable	Estimated Coefficient	Standard Error	t-statistic
C	258134.	63447.2	4.06849
WSSPSN(-4)	.291569	.170965	1.70544
WAPINSN	-.224391E+07	.136225E+07	-1.64720
CDDSPS	31.5258	10.0134	3.14836

EQUATION 8: TEXAS RESIDENTIAL AVERAGE PRICE

RAPSPST=h0+h1*AVCRSPS+h2*AFCSPS+h3*APTDUM1+h4*APTDUM2+h5*APTDUM4

Number of observations: 43
Mean of dependent variable = .069775
Std. dev. of dependent var. = .604477E-02
Sum of squared residuals = .427462E-03

Variance of residuals = .115530E-04
Std. error of regression = .339897E-02
R-squared = .723475
Adjusted R-squared = .686107
Durbin-Watson statistic = 1.63947
F-statistic (zero slopes) = 19.1671
E'PZ*E = .274792E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.021682	.723459E-02	2.99704
AVCRSPS	1.39002	.167943	8.27674
AFCSPS	.404849	.150566	2.68884
APTDUM1	-.011940	.344400E-02	-3.46676
APTDUM2	-.966618E-02	.352485E-02	-2.74230
APTDUM4	-.659558E-02	.360723E-02	-1.82843

EQUATION 9: TEXAS COMMERCIAL AVERAGE PRICE

CAPSPST=i0+i1*AVCRSPS+i2*AFCSPS+i3*APTDUM1+i4*APTDUM3+i5*APTDUM4

Number of observations: 45
Mean of dependent variable = .064209
Std. dev. of dependent var. = .568130E-02
Sum of squared residuals = .425819E-03
Variance of residuals = .109184E-04
Std. error of regression = .330431E-02
R-squared = .701844
Adjusted R-squared = .663619
Durbin-Watson statistic = 1.84088
F-statistic (zero slopes) = 18.2147
E'PZ*E = .222710E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.017891	.597228E-02	2.99568
AVCRSPS	1.10762	.153533	7.21423
AFCSPS	.640766	.123379	5.19348
APTDUM1	-.011551	.334734E-02	-3.45067
APTDUM3	-.961302E-02	.336790E-02	-2.85431
APTDUM4	-.922287E-02	.349247E-02	-2.64079

EQUATION 10: TEXAS INDUSTRIAL AVERAGE PRICE

IAPSPST=j0+j1*AVCRSPS+j2*AFCSPS

Number of observations: 45
Mean of dependent variable = .042010
Std. dev. of dependent var. = .508023E-02
Sum of squared residuals = .410843E-03
Variance of residuals = .978197E-05
Std. error of regression = .312761E-02
R-squared = .640806

Adjusted R-squared = .623701
Durbin-Watson statistic = 1.63156
F-statistic (zero slopes) = 37.0447
E'PZ*E = .306851E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.226974E-02	.550744E-02	.412122
AVCRSPS	1.23745	.139226	8.88800
AFCSPS	.232882	.115936	2.00871

EQUATION 11: NON TEXAS RESIDENTIAL AVERAGE PRICE

RAPSNS=k0+k1*AVCRSPS+k2*AFCSPS

Number of observations: 43
(Statistics based on transformed data)
Mean of dependent variable = .047810
Std. dev. of dependent var. = .397231E-02
Sum of squared residuals = .405659E-03
Variance of residuals = .101415E-04
Std. error of regression = .318457E-02
R-squared = .391399
Adjusted R-squared = .360969
Durbin-Watson statistic = 1.96700
Rho (autocorrelation coef.) = .272677
Standard error of rho = .146720
t-statistic for rho = 1.85849
Log of likelihood function = 187.766
(Statistics based on original data)
Mean of dependent variable = .065698
Std. dev. of dependent var. = .482992E-02
Sum of squared residuals = .405659E-03
Variance of residuals = .101415E-04
Std. error of regression = .318457E-02
R-squared = .586001
Adjusted R-squared = .565301
Durbin-Watson statistic = 1.96700

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.029622	.876382E-02	3.38000
AVCRSPS	1.03491	.195460	5.29474
AFCSPS	.294438	.191443	1.53799

EQUATION 12: NON TEXAS COMMERCIAL AVERAGE PRICE

CAPSPSN=l0+l1*AVCRSPS+l2*AFCSPS

Number of observations: 43
(Statistics based on transformed data)
Mean of dependent variable = .034241

Std. dev. of dependent var. = .299249E-02
Sum of squared residuals = .272942E-03
Variance of residuals = .682354E-05
Std. error of regression = .261219E-02
R-squared = .278358
Adjusted R-squared = .242276
Durbin-Watson statistic = 2.22918
Rho (autocorrelation coef.) = .481018
Standard error of rho = .133697
t-statistic for rho = 3.59782
Log of likelihood function = 196.286
(Statistics based on original data)
Mean of dependent variable = .065845
Std. dev. of dependent var. = .444816E-02
Sum of squared residuals = .272942E-03
Variance of residuals = .682354E-05
Std. error of regression = .261219E-02
R-squared = .673810
Adjusted R-squared = .657501
Durbin-Watson statistic = 2.22918

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.031938	.956273E-02	3.33983
AVCRSPS	.834386	.203315	4.10391
AFCSPS	.419297	.220651	1.90027

EQUATION 13: NON TEXAS INDUSTRIAL AVERAGE PRICE

IAPSPSN=m0+m1*AVCRSPS+m2*AFCSPS

Number of observations: 45
Mean of dependent variable = .044746
Std. dev. of dependent var. = .566392E-02
Sum of squared residuals = .675168E-03
Variance of residuals = .160754E-04
Std. error of regression = .400942E-02
R-squared = .521726
Adjusted R-squared = .498952
Durbin-Watson statistic = 1.73580
F-statistic (zero slopes) = 22.9031
E'PZ*E = .504616E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.775402E-03	.703737E-02	.110183
AVCRSPS	1.15645	.177383	6.51950
AFCSPS	.476212	.148719	3.20210

EQUATION 14: NON TEXAS WHOLESALE AVERAGE PRICE

WAPSPSN=n0+n1*AVCRSPS+n2*AFCSPS+n3*WAPNDUM

Number of observations: 43
(Statistics based on transformed data)
Mean of dependent variable = .016496
Std. dev. of dependent var. = .445650E-02
Sum of squared residuals = .344071E-03
Variance of residuals = .882233E-05
Std. error of regression = .297024E-02
R-squared = .587526
Adjusted R-squared = .555797
Durbin-Watson statistic = 2.33856
Rho (autocorrelation coef.) = .552665
Standard error of rho = .127093
t-statistic for rho = 4.34851
Log of likelihood function = 191.307
(Statistics based on original data)
Mean of dependent variable = .036627
Std. dev. of dependent var. = .609828E-02
Sum of squared residuals = .344071E-03
Variance of residuals = .882233E-05
Std. error of regression = .297024E-02
R-squared = .780176
Adjusted R-squared = .763266
Durbin-Watson statistic = 2.33856

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.207234E-02	.011978	.173016
AVCRSPS	.891956	.245497	3.63326
AFCSPS	.402256	.288632	1.39366
WAPNDUM	-.015333	.263653E-02	-5.81571

EQUATION 15: TOTAL FUEL EXPENSE

VCRSPS=p0+p1*VCESPS+p2*VCRDUM

Number of observations: 44
(Statistics based on transformed data)
Mean of dependent variable = 49473.0
Std. dev. of dependent var. = 11159.0
Sum of squared residuals = .160024E+10
Variance of residuals = .390302E+08
Std. error of regression = 6247.42
R-squared = .703733
Adjusted R-squared = .689280
Durbin-Watson statistic = 1.74672
Rho (autocorrelation coef.) = .484134
Standard error of rho = .131910
t-statistic for rho = 3.67018
Log of likelihood function = -445.436
(Statistics based on original data)
Mean of dependent variable = 95470.0
Std. dev. of dependent var. = 13257.4

Sum of squared residuals = .160024E+10
Variance of residuals = .390302E+08
Std. error of regression = 6247.42
R-squared = .789339
Adjusted R-squared = .779063
Durbin-Watson statistic = 1.74672

Variable	Estimated Coefficient	Standard Error	t-statistic
C	21206.6	7671.18	2.76445
VCESPS	.829656	.085535	9.69960
VCRDUM	20344.4	3407.45	5.97057

4-7 SOUTHWESTERN ELECTRIC POWER COMPANY

MODEL: SWEPCO

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCSWE	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRSWE	-	AVERAGE FUEL EXPENSES AND PURCHASED POWER COSTS:000'S OF $ PER MWH
CAPINST	-	INSTRUMENT FOR CAPSWET
CAPSWEN	-	COMMERCIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
CAPSWET	-	COMMERCIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
CSSWEN	-	COMMERCIAL SALES (NON-TEXAS):MWH
CSSWET	-	COMMERCIAL SALES (TEXAS):MWH
GENRSWE	-	GENERATION REQUIREMENTS:MWH
GRNG	-	GENERATION REQUIREMENTS FROM NATURAL GAS PLANT:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENT FROM PLANT D:MWH
GRPLNTE	-	GENERATION REQUIREMENT FROM PLANT E:MWH
GRPLNTF	-	GENERATION REQUIREMENT FROM PLANT F:MWH
GRPLNTG	-	GENERATION REQUIREMENT FROM PLANT G:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPINST	-	INSTRUMENT FOR IAPSWET
IAPSWEN	-	INDUSTRIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
IAPSWET	-	INDUSTRIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
ISSWEN	-	INDUSTRIAL SALES (NON-TEXAS):MWH
ISSWET	-	INDUSTRIAL SALES (TEXAS):MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE
PLNTEC	-	CONDITIONAL VARIABLE

PLNTFC	-	CONDITIONAL VARIABLE
PLNTGC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RAPSWEN	-	RESIDENTIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
RAPSWET	-	RESIDENTIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
RSSWEN	-	RESIDENTIAL SALES (NON-TEXAS):MWH
RSSWET	-	RESIDENTIAL SALES (TEXAS):MWH
TSSWE	-	TOTAL SYSTEM SALES:MWH
TSSWEN	-	TOTAL NON-TEXAS SYSTEM SALES:MWH
TSSWET	-	TOTAL TEXAS SYSTEM SALES:MWH
VCESWE	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE: 000'S OF $
VCNG	-	NATURAL GAS COST:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B:000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANT C:000'S OF $
VCPLNTD	-	VARIABLE COST FOR PLANT D:000'S OF $
VCPLNTE	-	VARIABLE COST FOR PLANT E:000'S OF $
VCPLNTF	-	VARIABLE COST FOR PLANT F:000'S OF $
VCPLNTG	-	VARIABLE COST FOR PLANT G:000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $
VCRSWE	-	TOTAL FUEL AND PURCHASED POWER EXPENSE REPORTED: 000'S OF $

EXOGENOUS:

CCDDINSN	-	INSTRUMENT FOR (NON-TEXAS) COMMERCIAL COOLING DEGREE DAYS
CCDDINST	-	INSTRUMENT FOR (TEXAS) COMMERCIAL COOLING DEGREE DAYS
CCSWET	-	COMMERCIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
CDDSWE	-	COOLING DEGREE DAYS:NUMBER OF DAYS
CHDDINSN	-	INSTRUMENT FOR (NON-TEXAS) COMMERCIAL HEATING DEGREE DAYS
CHDDINST	-	INSTRUMENT FOR (TEXAS) COMMERCIAL HEATING DEGREE DAYS
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLNTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLNTC	-	GENERATION CAPABILITY OF PLANT C:MWH
GCPLNTD	-	GENERATION CAPABILITY OF PLANT D:MWH

GCPLNTE	-	GENERATION CAPABILITY OF PLANT E:MWH
GCPLNTF	-	GENERATION CAPABILITY OF PLANT F:MWH
GCPLNTG	-	GENERATION CAPABILITY OF PLANT G:MWH
GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
LFSWE	-	LOSS FACTOR
MATFCSWE	-	FOUR-QUARTER MOVING AVERAGE TOTAL FIXED COSTS:000'S OF $
NAGSWEN	-	NON-AGRICULTURAL EMPLOYMENT IN NON-TEXAS SERVICE AREA: 000'S OF PERSONS
OSSWEN	-	OTHER RETAIL SALES(NON-TEXAS):MWH
OSSWET	-	OTHER RETAIL SALES(TEXAS):MWH
PNGCSWE	-	PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS: $ PER MCF
PNGISWE	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS: $ PER MCF
POPSWET	-	SERVICE AREA POPULATION (TEXAS):000'S OF PERSONS
RCDDINSN	-	INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL COOLING DEGREE DAYS
RCDDINST	-	INSTRUMENT FOR (TEXAS) RESIDENTIAL COOLING DEGREE DAYS
RHDDINSN	-	INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL HEATING DEGREE DAYS
RHDDINST	-	INSTRUMENT FOR (TEXAS) RESIDENTIAL HEATING DEGREE DAYS
RPISWEN	-	REAL PERSONAL INCOME (NON-TEXAS):BILLIONS OF $
RPISWET	-	REAL PERSONAL INCOME (TEXAS):BILLIONS OF $
UFCNG	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN NATURAL GAS PLANT:000'S OF $
UFCPLNTA	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT A: 000'S OF $ PER MWH
UFCPLNTB	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT B: 000'S OF $ PER MWH
UFCPLNTC	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT C: 000'S OF $ PER MWH
UFCPLNTD	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT D: 000'S OF $ PER MWH
UFCPLNTE	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT E: 000'S OF $ PER MWH
UFCPLNTF	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT F: 000'S OF $ PER MWH
UFCPLNTG	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT G: 000'S OF $ PER MWH
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES: 000'S OF $ PER MWH

WSSWEN	-	WHOLESALE NON-TEXAS SALES:MWH
WSSWET	-	WHOLESALE TEXAS SALES:MWH

IDENTITIES

CAPINST	=	(CAPSWET(-3)/PNGCSWE(-3))*CCSWET
IAPINST	=	IAPSWET/PNGISWE
TSSWET	=	RSSWET+CSSWET+ISSWET+OSSWET+WSSWET
TSSWEN	=	RSSWEN+CSSWEN+ISSWEN+OSSWEN+WSSWEN
TSSWE	=	TSSWET+TSSWEN
AFCSWE	=	MATFCSWE/(TSSWE+TSSWE(-1)+TSSWE(-2)+TSSWE(-3))
AVCRSWE	=	VCRSWE/TSSWE
GENRSWE	=	(1/(1-LFSWE))*TSSWE
PPCC	=	GENRSWE-GCPPC;
PLNTAC	=	PPCC-GCPLNTA
PLNTBC	=	PLNTAC-GCPLNTB
PLNTCC	=	PLNTBC-GCPLNTC
PLNTDC	=	PLNTCC-GCPLNTD
PLNTEC	=	PLNTDC-GCPLNTE
PLNTFC	=	PLNTEC-GCPLNTF
PLNTGC	=	PLNTFC-GCPLNTG
GRPPC	=	(PPCC>0)*GCPPC+(PPCC<=0)*GENRSWE
VCPPC	=	GRPPC*UFCPPC/1000
GRPLNTA	=	(PPCC>0)*((PLNTAC>0)*GCPLNTA+(PLNTAC<=0)*PPCC)
VCPLNTA	=	GRPLNTA*UFCPLNTA/1000
GRPLNTB	=	(PPCC>0)*(PLNTAC>0)*((PLNTBC>0)*GCPLNTB+(PLNTBC<=0)* PLNTAC)
VCPLNTB	=	GRPLNTB*UFCPLNTB/1000
GRPLNTC	=	(PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*((PLNTCC>0)*GCPLNTC+ (PLNTCC<=0)*PLNTBC)

VCPLNTC	=	GRPLNTC*UFCPLNTC/1000
GRPLNTD	=	(PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*((PLNTDC>0)* GCPLNTD+ (PLNTDC<=0)*PLNTCC)
VCPLNTD	=	GRPLNTD*UFCPLNTD/1000
GRPLNTE	=	(PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)* ((PLNTEC>0)*GCPLNTE+(PLNTEC<=0)*PLNTDC)
VCPLNTE	=	GRPLNTE*UFCPLNTE/1000
GRPLNTF	=	(PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0) *(PLNTEC>0)*((PLNTFC>0)*GCPLNTF+(PLNTFC<=0)*PLNTEC)
VCPLNTF	=	GRPLNTF*UFCPLNTF/1000
GRPLNTG	=	(PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)* (PLNTEC>0)* (PLNTFC>0)*((PLNTGC>0)*GCPLNTG+(PLNTGC<=0)* PLNTFC)
VCPLNTG	=	GRPLNTG*UFCPLNTG/1000
GRNG	=	(PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)* (PLNTEC>0)* (PLNTFC>0)*(PLNTGC>0)*PLNTGC
VCNG	=	GRNG*UFCNG/1000
VCESWE	=	VCPPC+ VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+VCPLNTE+ VCPLNTF+VCPLNTG+VCNG

EQUATION ESTIMATES

EQUATION 1: TEXAS RESIDENTIAL SALES

RSSWET=a0+a1*RSSWET(-1)+a2*RPISWET+a3*RCDDINST+a4*RHDDINST

Number of observations = 59
Mean of dependent variable = 336325.
Std. dev. of dependent var. = 96217.6
Sum of squared residuals = .336870E+11
Variance of residuals = .623833E+09
Std. error of regression = 24976.6
R-squared = .937263
Adjusted R-squared = .932616
Durbin-Watson statistic = 2.34436
Durbin's h alternative = -1.33283
F-statistic (zero slopes) = 201.683
Schwarz Bayes. Info. Crit. = 20.5084
Log of likelihood function = -678.521

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-233039.	47804.6	-4.87483
RSSWET(-1)	.135929	.043407	3.13150
RPISWET	267978.	53902.7	4.97152
RCDDINST	.240612E-02	.113170E-03	21.2611
RHDDINST	.113761E-02	.867296E-04	13.1167

EQUATION 2: NON-TEXAS RESIDENTIAL SALES

RSSWEN=b0+b1*RSSWEN(-4)+b2*RPISWEN+b3*RCDDINSN+b4*RHDDINSN

Number of observations = 56
Mean of dependent variable = 499045.
Std. dev. of dependent var. = 150203.
Sum of squared residuals = .334408E+11
Variance of residuals = .655702E+09
Std. error of regression = 25606.7
R-squared = .973050
Adjusted R-squared = .970936
Durbin-Watson statistic = 1.73428
Durbin's h alternative = .366568
F-statistic (zero slopes) = 460.348
Schwarz Bayes. Info. Crit. = 20.5671
Log of likelihood function = -645.276

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-106675.	39701.2	-2.68694
RSSWEN(-4)	.423597	.056267	7.52834
RPISWEN	105711.	23911.6	4.42090
RCDDINSN	.131646E-02	.123422E-03	10.6664
RHDDINSN	.564536E-03	.662022E-04	8.52745

EQUATION 3: TEXAS COMMERCIAL SALES

CSSWET=c0+c1*CSSWET(-4)+c2*CAPINST+c3*CCDDINST+c4*CHDDINST

Number of observations = 54
(Statistics based on transformed data)
Mean of dependent variable = 197925.
Std. dev. of dependent var. = 49782.6
Sum of squared residuals = .383584E+10
Variance of residuals = .782824E+08
Std. error of regression = 8847.74
R-squared = .970831
Adjusted R-squared = .968450
Durbin-Watson statistic = 1.96571
Rho (autocorrelation coef.) = .227346
Standard error of rho = .132519
t-statistic for rho = 1.71557

Log of likelihood function = -564.747
(Statistics based on original data)
Mean of dependent variable = 255524.
Std. dev. of dependent var. = 54437.5
Sum of squared residuals = .383584E+10
Variance of residuals = .782824E+08
Std. error of regression = 8847.74
R-squared = .975589
Adjusted R-squared = .973597
Durbin-Watson statistic = 1.96571

Variable	Estimated Coefficient	Standard Error	t-statistic
C	67357.2	19422.1	3.46806
CSSWET(-4)	.854274	.039748	21.4920
CAPINST	-199.215	86.9807	-2.29033
CCDDINST	.140996E-02	.324598E-03	4.34372
CHDDINST	.675730E-03	.214205E-03	3.15459

EQUATION 4: NON-TEXAS COMMERCIAL SALES

CSSWEN=d0+d1*CSSWEN(-1)+d2*NAGSWEN+d3*CCDDINSN+d4*CHDDINSN

Number of observations = 54
(Statistics based on transformed data)
Mean of dependent variable = 181584.
Std. dev. of dependent var. = 69581.1
Sum of squared residuals = .490453E+10
Variance of residuals = .100093E+09
Std. error of regression = 10004.6
R-squared = .980887
Adjusted R-squared = .979326
Durbin-Watson statistic = 2.15373
Rho (autocorrelation coef.) = .520495
Standard error of rho = .129405
t-statistic for rho = 4.02222
F-statistic (zero slopes) = 628.659
Log of likelihood function = -571.383
(Statistics based on original data)
Mean of dependent variable = 375889.
Std. dev. of dependent var. = 76007.1
Sum of squared residuals = .490453E+10
Variance of residuals = .100093E+09
Std. error of regression = 10004.6
R-squared = .984002
Adjusted R-squared = .982696
Durbin-Watson statistic = 2.15373

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-281746.	43024.7	-6.54848
CSSWEN(-1)	.155088	.024812	6.25061
NAGSWEN	1518.95	143.805	10.5625

CCDDINSN	.638047E-02	.179647E-03	35.5166
CHDDINSN	.199863E-02	.148506E-03	13.4582
RHO	.520495	.129405	4.02222

EQUATION 5: TEXAS INDUSTRIAL SALES

ISSWET=c0+c1*ISSWET*(-1)+c2*IAPINST(-4)+c3*POPSWET+c4*CDDSWE

Number of observations = 54
(Statistics based on transformed data)
Mean of dependent variable = 340931.
Std. dev. of dependent var. = 63479.4
Sum of squared residuals = .421824E+11
Variance of residuals = .860864E+09
Std. error of regression = 29340.5
R-squared = .802491
Adjusted R-squared = .786367
Durbin-Watson statistic = 1.70221
Rho (autocorrelation coef.) = .502885
Standard error of rho = .117624
t-statistic for rho = 4.27538
Log of likelihood function = -629.482
(Statistics based on original data)
Mean of dependent variable = 678665.
Std. dev. of dependent var. = 119783.
Sum of squared residuals = .421824E+11
Variance of residuals = .860864E+09
Std. error of regression = 29340.5
R-squared = .944529
Adjusted R-squared = .940001
Durbin-Watson statistic = 1.70221

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-353551.	342028.	-1.03369
ISSWET(-1)	.634564	.096762	6.55800
IAPINST(-4)	-.262478E+07	.127991E+07	-2.05075
POPSWET	1392.81	820.060	1.69843
CDDSWE	26.6940	6.07819	4.39177

EQUATION 6: NON-TEXAS INDUSTRIAL SALES

ISSWEN=f0+f1*ISSWEN(-1)+f2*NAGSWEN+f3*CDDSWE

Number of observations = 54
(Statistics based on transformed data)
Mean of dependent variable = 315406.
Std. dev. of dependent var. = 46922.9
Sum of squared residuals = .725781E+10
Variance of residuals = .145156E+09
Std. error of regression = 12048.1
R-squared = .937804

Adjusted R-squared = .934073
Durbin-Watson statistic = 2.13614
Rho (autocorrelation coef.) = .382964
Standard error of rho = .141971
t-statistic for rho = 2.69749
F-statistic (zero slopes) = 251.305
Log of likelihood function = -581.964
(Statistics based on original data)
Mean of dependent variable = 509077.
Std. dev. of dependent var. = 61234.4
Sum of squared residuals = .725781E+10
Variance of residuals = .145156E+09
Std. error of regression = 12048.1
R-squared = .963480
Adjusted R-squared = .961289
Durbin-Watson statistic = 2.13614

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-177248.	39778.6	-4.45587
ISSWEN(-1)	.250697	.055249	4.53762
NAGSWEN	1636.28	169.715	9.64131
CDDSWE	54.1041	2.80268	19.3044
RHO	.382964	.141971	2.69749

EQUATION 7: TEXAS RESIDENTIAL AVERAGE PRICE

RAPSWET=g0+g1*AVCRSWE+g2*AFCSWE

Number of observations = 57
Mean of dependent variable = .056773
Std. dev. of dependent var. = .014837
Sum of squared residuals = .164098E-02
Variance of residuals = .303885E-04
Std. error of regression = .551258E-02
R-squared = .866889
Adjusted R-squared = .861959
Durbin-Watson statistic = 2.06808
F-statistic (zero slopes) = 175.833
E'PZ*E = .123523E-02

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.484999E-03	.323450E-02	.149946
AVCRSWE	.270366	.178024	1.51871
AFCSWE	1.74102	.139342	12.4945

EQUATION 8: TEXAS COMMERCIAL AVERAGE PRICE

CAPSWET=h0+h1*AVCRSWE+h2*AFCSWE

Number of observations = 57

Mean of dependent variable = .047047
Std. dev. of dependent var. = .939607E-02
Sum of squared residuals = .366480E-03
Variance of residuals = .678666E-05
Std. error of regression = .260512E-02
R-squared = .925876
Adjusted R-squared = .923131
Durbin-Watson statistic = 2.02580
F-statistic (zero slopes) = 337.245
E'PZ*E = .257768E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.998585E-02	.152855E-02	6.53288
AVCRSWE	.222775	.084130	2.64798
AFCSWE	1.11156	.065850	16.8801

EQUATION 9: TEXAS INDUSTRIAL AVERAGE PRICE

IAPSWET=i0+i1*AVCRSWE+i2*AFCSWE

Number of Observations = 57
Mean of dependent variable = .034972
Std. dev. of dependent var. = .775009E-02
Sum of squared residuals = .276272E-03
Variance of residuals = .511616E-05
Std. error of regression = .226189E-02
R-squared = .917865
Adjusted R-squared = .914822
Durbin-Watson statistic = 1.57132
F-statistic (zero slopes) = 301.721
E'PZ*E = .184162E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.379179E-02	.132716E-02	2.85706
AVCRSWE	.364388	.073046	4.98849
AFCSWE	.797758	.057174	13.9531

EQUATION 10: NON-TEXAS RESIDENTIAL AVERAGE PRICE

RAPSWEN=j0+j1*AVCRSWE+j2*AFCSWE

Number of Observations = 55
(Statistics based on transformed data)
Mean of dependent variable = .010503
Std. dev. of dependent var. = .503134E-02
Sum of squared residuals = .923592E-03
Variance of residuals = .177614E-04
Std. error of regression = .421442E-02
R-squared = .325724
Adjusted R-squared = .299790

Durbin-Watson statistic = 1.92342
Rho (autocorrelation coef.) = .821128
Standard error of rho = .076959
t-statistic for rho = 10.6697
Log of likelihood function = 224.309
(Statistics based on original data)
Mean of dependent variable = .055519
Std. dev. of dependent var. = .013834
Sum of squared residuals = .923592E-03
Variance of residuals = .177614E-04
Std. error of regression = .421442E-02
R-squared = .911151
Adjusted R-squared = .907734
Durbin-Watson statistic = 1.92342

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.103640E-02	.015278	-.067834
AVCRSWE	.892604	.226092	3.94796
AFCSWE	1.25321	.479375	2.61426

EQUATION 11: NON-TEXAS COMMERCIAL AVERAGE PRICE

CAPSWEN=k0+k1*AVCRSWE+k2*AFCSWE

Number of observations = 55
(Statistics based on transformed data)
Mean of dependent variable = .012857
Std. dev. of dependent var. = .386319E-02
Sum of squared residuals = .430734E-03
Variance of residuals = .828334E-05
Std. error of regression = .287808E-02
R-squared = .465952
Adjusted R-squared = .445412
Durbin-Watson statistic = 1.90548
Rho (autocorrelation coef.) = .737518
Standard error of rho = .091061
t-statistic for rho = 8.09914
Log of likelihood function = 245.286
(Statistics based on original data)
Mean of dependent variable = .047405
Std. dev. of dependent var. = .011254
Sum of squared residuals = .430734E-03
Variance of residuals = .828334E-05
Std. error of regression = .287808E-02
R-squared = .937346
Adjusted R-squared = .934936
Durbin-Watson statistic = 1.90548

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.127972E-02	.715584E-02	.178835
AVCRSWE	.361123	.154378	2.33922

AFCSWE	1.29844	.232843	5.57646

EQUATION 12: NON-TEXAS INDUSTRIAL AVERAGE PRICE

IAPSWEN=I0+I1*AVCRSWE+I2*AFCSWE

Number of observations = 55
(Statistics based on transformed data)
Mean of dependent variable = .023153
Std. dev. of dependent var. = .605348E-02
Sum of squared residuals = .441572E-03
Variance of residuals = .849177E-05
Std. error of regression = .291406E-02
R-squared = .776896
Adjusted R-squared = .768315
Durbin-Watson statistic = 1.68216
Rho (autocorrelation coef.) = .413124
Standard error of rho = .122795
t-statistic for rho = 3.36433
Log of likelihood function = 244.602
(Statistics based on original data)
Mean of dependent variable = .039127
Std. dev. of dependent var. = .986654E-02
Sum of squared residuals = .441572E-03
Variance of residuals = .849177E-05
Std. error of regression = .291406E-02
R-squared = .916006
Adjusted R-squared = .912775
Durbin-Watson statistic = 1.68216

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.138604E-02	.321262E-02	-.431435
AVCRSWE	.157698	.132963	1.18603
AFCSWE	1.25870	.118224	10.6467

EQUATION 13: TOTAL FUEL EXPENSE AND PURCHASE POWER COST

VCRSWE=m0+m1*VCESWE

Number of observations = 57
Mean of dependent variable = 72439.8
Std. dev. of dependent var. = 23631.4
Sum of squared residuals = .507056E+10
Variance of residuals = .921921E+08
Std. error of regression = 9601.67
R-squared = .852888
Adjusted R-squared = .850213
Durbin-Watson statistic = 1.82710
F-statistic (zero slopes) = 284.212
E'PZ*E = .233326E+10

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-6.96798	4505.30	-.154662E-02
VCESWE	1.04025	.062060	16.7620

4-8 LOWER COLORADO RIVER AUTHORITY

MODEL: LCRA

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCLCR	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRLCR	-	AVERAGE FUEL AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CSLCR	-	COMMERCIAL SALES:MWH
GENRLCR	-	GENERATION REQUIREMENTS:MWH
GRNG	-	GENERATION REQUIREMENTS FROM NATURAL GAS PLANT:MWH
GRHY	-	GENERATION REQUIREMENTS FROM HYDROELECTRIC:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
HYC	-	CONDITIONAL VARIABLE
IAPINST	-	INSTRUMENT FOR INDUSTRIAL AVERAGE PRICE
ISLCR	-	INDUSTRIAL SALES:MWH
OSLCR	-	OTHER SALES: MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RSLCR	-	RESIDENTIAL SALES:MWH
TSLCR	-	TOTAL SYSTEM SALES:MWH
VCELCR	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE: 000'S OF $
VCNG	-	NATURAL GAS COST:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A: 000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B: 000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $
VCRLCR	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST REPORTED:000'S OF $
WAPLCR	-	WHOLESALE AVERAGE PRICE:000'S OF $ PER MWH

EXOGENOUS:

ADJF	-	ADJUSTMENT FACTOR TO ADJUST RECORD 20 DATA TO THE SALES DATA IN LOAD AND CAPACITY RESOURCE FORECAST FILING
CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CDDLCR	-	COOLING DEGREE DAYS
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
CSDUM1	-	DUMMY IN COMMERCIAL SALES EQUATION
GCPPC	-	GENERATION CAPABILITY OF PURCAHASED POWER FROM NON-UTILITY SOURCES:MWH
GCHY	-	GENERATION CAPABILITY OF HYDROELECTRIC PLANT:MWH
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLNTB	-	GENERATION CAPABILITY OF PLANT B:MWH
HDDLCR	-	HEATING DEGREE DAYS: NUMBER OF DAYS
ISDUM1	-	DUMMY IN INDUSTRIAL SALES EQUATION
ISDUM2	-	DUMMY IN INDUSTRIAL SALES EQUATION
LFLCR	-	LOSS FACTOR
MATFCLCR	-	FOUR QUARTER MOVING AVERAGE TOTAL FIXED COSTS:000'S OF DOLLARS
NAGLCR	-	NON-AGRICULTURAL EMPLOYMENT IN LCRA SERVICE AREA:000'S OF PERSONS
OSLCR	-	OTHER SALES:MWH
PNGILCR	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS: $ PER MCF
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPILCR	-	REAL PERSONAL INCOME (BILLIONS OF DOLLARS)
UFCNG	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN NATURAL GAS PLANT: 000'S OF $
UFCPLNTA	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT A :000'S OF $
UFCPLNTB	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT B:000'S OF $
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH

IDENTITIES

IAPINST=WAPLCR(-4)/PNGILCR(-4)

TSLCR=(RSLCR+CSLCR+ISLCR+OSLCR)*ADJF

AFCLCR=MATFCLCR/
(TSLCR+TSLCR(-1)+TSLCR(-2)+TSLCR(-3))

AVCRLCR=VCRLCR/TSLCR

GENRLCR = TSLCR/(1-LFLCR)

PPCC = GENRLCR-GCPPC
HYC = PPCC-GCHY
PLNTAC = HYC-GCPLNTA
PLNTBC = PLNTAC-GCPLNTB

GRPPC = (PPCC>0)*GCPPC+(PPCC<0)*GENRLCR
VCPPC = GRPPC*UFCPPC/1000
GRHY = (PPCC>0)*((HYC>0)*GCHY+(HYC<0)*PPCC)
GRPLNTA = (PPCC>0)*(HYC>0)*
((PLNTAC>0)*GCPLNTA+(PLNTAC<0)*HYC)
VCPLNTA = GRPLNTA*UFCPLNTA/1000
GRPLNTB = (PPCC>0)*(HYC>0)*(PLNTAC>0)*
((PLNTBC>0)*GCPLNTB+(PLNTBC<0)*PLNTAC)
VCPLNTB = GRPLNTB*UFCPLNTB/1000
GRNG = (PPCC>0)*(HYC>0)*(PLNTAC>0)*(PLNTBC>0)*PLNTBC
VCNG = GRNG*UFCNG/1000

VCELCR = VCPPC+VCPLNTA+VCPLNTB+VCNG

EQUATION ESTIMATES

<u>EQUATION 1: RESIDENTIAL SALES</u>

RSLCR=a0+a1*RSLCR(-4)+a2*RPILCR(-4)+a3*RCDDINST+a4*RHDDINST

Number of observations: 44
Mean of dependent variable = 799064.
Std. dev. of dependent var. = 190763.
Sum of squared residuals = .580683E+11
Variance of residuals = .148893E+10
Std. error of regression = 38586.7
R-squared = .962891
Adjusted R-squared = .959085
Durbin-Watson statistic = 2.49134
Durbin's h alternative = -1.59224
F-statistic (zero slopes) = 252.987
Schwarz Bayes. Info. Crit. = 21.4307
Log of likelihood function = -524.449

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-129986.	72645.1	-1.78933
RSLCR(-4)	.699376	.065961	10.6028

RPILCR(-4)	188746.	76687.4	2.46124
RCDDINST	.521223E-03	.117274E-03	4.44448
RHDDINST	.649365E-03	.152268E-03	4.26460

EQUATION 2: COMMERCIAL SALES

CSLCR=b0+b1*POPLCR(-4)+b2*CSDUM1+b3*CCDDINST+b4*CHDDINST

Number of observations: 48
Mean of dependent variable = 503880.
Std. dev. of dependent var. = 87536.6
Sum of squared residuals = .127944E+11
Variance of residuals = .297544E+09
Std. error of regression = 17249.5
R-squared = .964474
Adjusted R-squared = .961170
Durbin-Watson statistic = 1.74647
F-statistic (zero slopes) = 291.849
Schwarz Bayes. Info. Crit. = 19.8043
Log of likelihood function = -533.735

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-524929.	44820.5	-11.7118
POPLCR(-4)	1935.44	99.2869	19.4934
CSDUM1	-85633.1	8354.10	-10.2504
CCDDINST	.276796E-02	.222710E-03	12.4285
CHDDINST	.122363E-02	.350365E-03	3.49246

EQUATION 3: INDUSTRIAL SALES

ISLCR=c0+c1*ISLCR(-4)+c2*IAPINST+c3*NAGLCR+c4*ISDUM1+c5*ISDUM2

Number of observations: 44
Mean of dependent variable = 177326.
Std. dev. of dependent var. = 59234.9
Sum of squared residuals = .424178E+10
Variance of residuals = .111626E+09
Std. error of regression = 10565.3
R-squared = .971888
Adjusted R-squared = .968189
Durbin-Watson statistic = 1.93372
F-statistic (zero slopes) = 262.727
E'PZ*E = .446859E+09

Variable	Estimated Coefficient	Standard Error	t-statistic
C	9309.42	61556.9	.151233
ISLCR(-4)	.238739	.140917	1.69417
IAPINST	-.443368E+07	.207340E+07	-2.13836
NAGLCR	920.749	446.251	2.06330
ISDUM1	73394.2	7453.88	9.84645

ISDUM2	75611.0	9534.55	7.93021

EQUATION 4: OTHER SALES

OSLCR=d0+d1*OSLCR(-1)+d2*NAGLCR+d3*CDDLCR+d4*HDDLCR

Number of observations: 45
(Statistics based on transformed data)
Mean of dependent variable = 10789.7
Std. dev. of dependent var. = 6134.31
Sum of squared residuals = .209096E+09
Variance of residuals = .522740E+07
Std. error of regression = 2286.35
R-squared = .873712
Adjusted R-squared = .861083
Durbin-Watson statistic = 2.19621
Rho (autocorrelation coef.) = .743430
Standard error of rho = .088322
t-statistic for rho = 8.41730
F-statistic (zero slopes) = 69.1841
Log of likelihood function = -409.264
(Statistics based on original data)
Mean of dependent variable = 41342.3
Std. dev. of dependent var. = 9076.62
Sum of squared residuals = .209096E+09
Variance of residuals = .522740E+07
Std. error of regression = 2286.35
R-squared = .942689
Adjusted R-squared = .936958
Durbin-Watson statistic = 2.19621

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-91634.3	25633.0	-3.57486
OSLCR(-1)	.165701	.068526	2.41808
NAGLCR	767.380	174.716	4.39215
CDDLCR	10.0583	.792357	12.6942
HDDLCR	7.01889	1.13436	6.18751
RHO	.743430	.088322	8.41730

EQUATION 5: WHOLESALE AVERAGE PRICE

WAPLCR=e0+e1*AVCRLCR(-1)+e2*AFCLCR

Number of observations: 42
(Statistics based on transformed data)
Mean of dependent variable = .029032
Std. dev. of dependent var. = .366349E-02
Sum of squared residuals = .139141E-03
Variance of residuals = .356771E-05
Std. error of regression = .188884E-02
R-squared = .747246

Adjusted R-squared = .734285
Durbin-Watson statistic = 2.01299
Rho (autocorrelation coef.) = .241455
Standard error of rho = .149738
t-statistic for rho = 1.61252
Log of likelihood function = 205.376
(Statistics based on original data)
Mean of dependent variable = .038221
Std. dev. of dependent var. = .455230E-02
Sum of squared residuals = .139141E-03
Variance of residuals = .356771E-05
Std. error of regression = .188884E-02
R-squared = .836573
Adjusted R-squared = .828192
Durbin-Watson statistic = 2.01299

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.020284	.181946E-02	11.1486
AVCRLCR(-1)	.490864	.056664	8.66278
AFCLCR	.719640	.085146	8.45183

<u>EQUATION 6: TOTAL FUEL EXPENSE AND PURCHASED POWER COST</u>

VCRLCR=f0+f1*VCELCR

Number of observations: 32
Mean of dependent variable = 34057.0
Std. dev. of dependent var. = 8357.22
Sum of squared residuals = .371373E+09
Variance of residuals = .123791E+08
Std. error of regression = 3518.40
R-squared = .837834
Adjusted R-squared = .832428
Durbin-Watson statistic = 2.31190
F-statistic (zero slopes) = 144.902
E'PZ*E = .934355E+08

Variable	Estimated Coefficient	Standard Error	t-statistic
C	1712.23	2919.34	.586511
VCELCR	1.04071	.091774	11.3398

4-9 WEST TEXAS UTILITIES COMPANY

MODEL: WTU

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCWTU	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRWTU	-	AVERAGE FUEL AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CAPWTU	-	COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
CAPINST	-	INSTRUMENT FOR CAPWTU
CSWTU	-	COMMERCIAL SALES:MWH
GENRWTU	-	GENERATION REQUIREMENTS:MWH
GRNG	-	GENERATION REQUIREMENTS FROM NATURAL GAS PLANT:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENT FROM PLANT D:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPWTU	-	INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
ISWTU	-	INDUSTRIAL SALES:MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RAPWTU	-	RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
RSWTU	-	RESIDENTIAL SALES:MWH
TSWTU	-	TOTAL SYSTEM SALES:MWH
VCEWTU	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE: 000'S OF $
VCNG	-	NATURAL GAS COST:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A: 000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B: 000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANT C: 000'S OF $

VCPLNTD	-	VARIABLE COST FOR PLANT D: 000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $
VCRWTU	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST REPORTED:000'S OF $

EXOGENOUS:

CCWTU	-	COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
GCPPC	-	GENERATION CAPABILITY OF PURCAHASED POWER FROM NON-UTILITY SOURCES:MWH
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLNTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLNTC	-	GENERATION CAPABILITY OF PLANT C:MWH
GCPLNTD	-	GENERATION CAPABILITY OF PLANT D:MWH
ILFCSWTU	-	LOSS FACTOR: COMMERCIAL SALES
ILFISWTU	-	LOSS FACTOR: INDUSTRIAL SALES
ILFOSWTU	-	LOSS FACTOR: OTHER SALES
ILFRSWTU	-	LOSS FACTOR: RESIDENTIAL SALES
ILFWSWTU	-	LOSS FACTOR: WHOLESALE SALES
MATFCWTU	-	FOUR-QUARTER MOVING AVERAGE TOTAL FIXED COSTS:000'S OF DOLLARS
OSWTU	-	OTHER RETAIL SALES: MWH
POPWTU	-	POPULATION IN WTU SERVICE AREA:000'S OF PERSONS
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPIWTU	-	REAL PERSONAL INCOME (BILLIONS OF DOLLARS)
UFCNG	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN NATURAL GAS PLANT: 000'S OF $
UFCPLNTA	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT A :000'S OF $
UFCPLNTB	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT B:000'S OF $
UFCPLNTC	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT C:000'S OF $
UFCPLNTD	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY: IN PLANT D: 000'S OF $

UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH
VCRDUM1	-	DUMMY VARIABLE IN FUEL EXPENSE EQUATION
VCRDUM2	-	DUMMY VARIABLE IN FUEL EXPENSE EQUATION
WSWTU	-	WHOLESALE SALES: MWH

IDENTITIES:

```
CAPINST=(CAPWTU/CPITX)*CCWTU;

TSWTU=RSWTU+CSWTU+ISWTU+OSWTU+WSWTU;

AFCWTU=MATFCWTU/
 (TSWTU+TSWTU(-1)+TSWTU(-2)+TSWTU(-3));

AVCRWTU=VCRWTU/TSWTU;

GENRWTU = RSWTU*ILFRSWTU+CSWTU*ILFCSWTU+
 ISWTU*ILFISWTU+OSWTU*ILFOSWTU+
 WSWTU*ILFWSWTU;

PPCC = GENRWTU-GCPPC;
PLNTAC = PPCC-GCPLNTA;
PLNTBC = PLNTAC-GCPLNTB;
PLNTCC = PLNTBC-GCPLNTC;
PLNTDC = PLNTCC-GCPLNTD;

GRPPC = (PPCC>0)*GCPPC+(PPCC<=0)*GENRWTU;
VCPPC = GRPPC*UFCPPC/1000;
GRPLNTA = (PPCC>0)*( (PLNTAC>0)*GCPLNTA+(PLNTAC<=0)*PPCC);
VCPLNTA = GRPLNTA*UFCPLNTA/1000;
GRPLNTB = (PPCC>0)*(PLNTAC>0)*( (PLNTBC>0)*GCPLNTB+
 (PLNTBC<=0)*PLNTAC );
VCPLNTB = GRPLNTB*UFCPLNTB/1000;
GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*( (PLNTCC>0)*GCPLNTC+
 (PLNTCC<=0)*PLNTBC );
VCPLNTC = GRPLNTC*UFCPLNTC/1000;
GRPLNTD = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 ( (PLNTDC>0)*GCPLNTD+(PLNTDC<=0)*PLNTCC );
VCPLNTD = GRPLNTD*UFCPLNTD/1000;
GRNG = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 (PLNTDC>0)*PLNTDC;
VCNG = GRNG*UFCNG/1000;

VCEWTU =
 VCPPC+VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+
 +VCNG;
```

EQUATION ESTIMATES

EQUATION 1: RESIDENTIAL SALES

RSWTU=a0+a1*RSWTU(-4)+a2*RPIWTU+a3*RCDDINST+a4*RHDDINST

Dependent variable: RSWTU
Current sample: 1978:1 to 1991:4
Number of observations: 56

Mean of dependent variable = 306644.
Std. dev. of dependent var. = 73942.1
Sum of squared residuals = .106457E+11
Variance of residuals = .208739E+09
Std. error of regression = 14447.8
R-squared = .964598
Adjusted R-squared = .961821
Durbin-Watson statistic = 1.72187
Durbin's h alternative = .936631
F-statistic (zero slopes) = 347.400
Schwarz Bayes. Info. Crit. = 19.4225
Log of likelihood function = -613.226

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-69758.3	61182.6	-1.14017
RSWTU(-4)	.704406	.057637	12.2215
RPIWTU	87701.0	66509.7	1.31862
RCDDINST	.557225E-03	.100770E-03	5.52965
RHDDINST	.384902E-03	.740845E-04	5.19544

EQUATION 2: COMMERCIAL SALES

CSWTU=b0+b1*CSWTU(-1)+b2*CAPINST+b3*POPWTU+b4*CCDDINST+b5*CHDDINST

Number of observations: 57
Mean of dependent variable = 231677.
Std. dev. of dependent var. = 43261.1
Sum of squared residuals = .106859E+11
Variance of residuals = .209527E+09
Std. error of regression = 14475.0
R-squared = .898314
Adjusted R-squared = .888345
Durbin-Watson statistic = 1.98623
F-statistic (zero slopes) = 89.8399
E'PZ*E = .651581E+10

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-205060.	65125.0	-3.14872
CSWTU(-1)	.530643	.055552	9.55220
CAPINST	-64.5542	26.4244	-2.44298

POPWTU	676.742	204.887	3.30301
CCDDINST	.421427E-02	.322629E-03	13.0623
CHDDINST	.168732E-02	.310773E-03	5.42943

EQUATION 3: INDUSTRIAL SALES

ISWTU=c0+c1*ISWTU(-1)+c2*RPIWTU

Number of observations: 59
Mean of dependent variable = 287095.
Std. dev. of dependent var. = 17471.7
Sum of squared residuals = .768896E+10
Variance of residuals = .137303E+09
Std. error of regression = 11717.6
R-squared = .565723
Adjusted R-squared = .550213
Durbin-Watson statistic = 2.15429
Durbin's h alternative = -.885969
F-statistic (zero slopes) = 36.4750
Schwarz Bayes. Info. Crit. = 18.8928
Log of likelihood function = -634.940

Variable	Estimated Coefficient	Standard Error	t-statistic
C	29244.9	35382.2	.826544
ISWTU(-1)	.661485	.094352	7.01084
RPIWTU	70806.6	36135.3	1.95949

EQUATION 4: RESIDENTIAL AVERAGE PRICE

RAPWTU=d0+d1*AVCRWTU+d2*AFCWTU

Number of observations: 55
(Statistics based on transformed data)
Mean of dependent variable = .034198
Std. dev. of dependent var. = .837071E-02
Sum of squared residuals = .115169E-02
Variance of residuals = .221479E-04
Std. error of regression = .470616E-02
R-squared = .698353
Adjusted R-squared = .686751
Durbin-Watson statistic = 1.94622
Rho (autocorrelation coef.) = .480584
Standard error of rho = .118248
t-statistic for rho = 4.06421
Log of likelihood function = 218.239
(Statistics based on original data)
Mean of dependent variable = .065189
Std. dev. of dependent var. = .013731
Sum of squared residuals = .115169E-02
Variance of residuals = .221479E-04
Std. error of regression = .470616E-02

R-squared = .887431
Adjusted R-squared = .883102
Durbin-Watson statistic = 1.94622

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.775328E-02	.731022E-02	-1.06061
AVCRWTU	1.49314	.198667	7.51581
AFCWTU	1.22580	.124698	9.83012

EQUATION 5: COMMERCIAL AVERAGE PRICE

CAPWTU=c0+c1*AVCRWTU+c2*AFCWTU

Number of observations: 55
(Statistics based on transformed data)
Mean of dependent variable = .028227
Std. dev. of dependent var. = .537116E-02
Sum of squared residuals = .346620E-03
Variance of residuals = .666577E-05
Std. error of regression = .258182E-02
R-squared = .781006
Adjusted R-squared = .772584
Durbin-Watson statistic = 2.07356
Rho (autocorrelation coef.) = .490318
Standard error of rho = .116465
t-statistic for rho = 4.21001
Log of likelihood function = 251.260
(Statistics based on original data)
Mean of dependent variable = .054988
Std. dev. of dependent var. = .935839E-02
Sum of squared residuals = .346620E-03
Variance of residuals = .666577E-05
Std. error of regression = .258182E-02
R-squared = .926710
Adjusted R-squared = .923891
Durbin-Watson statistic = 2.07356

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.406407E-02	.407793E-02	.996602
AVCRWTU	1.25963	.110643	11.3846
AFCWTU	.652424	.069690	9.36181

EQUATION 6: INDUSTRIAL AVERAGE PRICE

IAPWTU=f0+f1*AVCRWTU+f2*AFCWTU

Number of observations: 57
Mean of dependent variable = .042954
Std. dev. of dependent var. = .891999E-02
Sum of squared residuals = .465925E-03

Variance of residuals = .862824E-05
Std. error of regression = .293739E-02
R-squared = .896891
Adjusted R-squared = .893073
Durbin-Watson statistic = 1.78941
F-statistic (zero slopes) = 231.205
E'PZ*E = .226838E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.335571E-02	.223532E-02	-1.50122
AVCRWTU	1.32708	.064702	20.5106
AFCWTU	.443820	.038544	11.5146

EQUATION 7: OTHER RETAIL AVERAGE PRICE

IAPWTU=g0+g1*AVCRWTU+g2*AFCWTU

Number of observations: 55
(Statistics based on transformed data)
Mean of dependent variable = .022327
Std. dev. of dependent var. = .571125E-02
Sum of squared residuals = .660424E-03
Variance of residuals = .127005E-04
Std. error of regression = .356377E-02
R-squared = .626024
Adjusted R-squared = .611640
Durbin-Watson statistic = 2.14099
Rho (autocorrelation coef.) = .553241
Standard error of rho = .112325
t-statistic for rho = 4.92538
Log of likelihood function = 233.532
(Statistics based on original data)
Mean of dependent variable = .049322
Std. dev. of dependent var. = .010847
Sum of squared residuals = .660424E-03
Variance of residuals = .127005E-04
Std. error of regression = .356377E-02
R-squared = .896467
Adjusted R-squared = .892485
Durbin-Watson statistic = 2.14099

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.270891E-02	.632424E-02	-.428337
AVCRWTU	1.11089	.169536	6.55253
AFCWTU	.832635	.109435	7.60846

EQUATION 8: TOTAL FUEL EXPENSE AND PURCHASED POWER COST

VCRWTU=h0+h1*VCEWTU+h2*VCRDUM1+h3*VCRDUM2

Number of observations: 57
Mean of dependent variable = 32256.4
Std. dev. of dependent var. = 9469.30
Sum of squared residuals = .888765E+09
Variance of residuals = .167692E+08
Std. error of regression = 4095.02
R-squared = .823083
Adjusted R-squared = .813069
Durbin-Watson statistic = 2.00016
F-statistic (zero slopes) = 82.1474
E'PZ*E = .461986E+09

Variable	Estimated Coefficient	Standard Error	t-statistic
C	654.419	2622.27	.249562
VCEWTU	1.07959	.096360	11.2037
VCRDUM1	-2998.50	1817.40	-1.64988
VCRDUM2	-8834.16	2229.39	-3.96259

4-10 EL PASO ELECTRIC COMPANY

MODEL: EPE

SYMBOL DECLARATIONS

ENDOGENOUS:

ACEPE	-	AVERAGE TOTAL COST: 000'S OF $ PER MWH
AFCEPE	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCREPE	-	AVERAGE FUEL AND PURCHASED POWER COSTS:000'S OF $ PER MWH
CAPEPEN	-	COMMERCIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
CAPEPET	-	COMMERCIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
GENREPE	-	GENERATION REQUIREMENTS:MWH
GRNG1	-	GENERATION REQUIREMENTS FROM NATURAL GAS
GRPLNTA	-	GENERATION REQUIREMENTS FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENTS FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENTS FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENTS FROM PLANT D:MWH
GRPLNTE	-	GENERATION REQUIREMENTS FROM PLANT E:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPEPET	-	INDUSTRIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE
PPNTEC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RAPEPEN	-	RESIDENTIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
RAPEPET	-	RESIDENTIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
RAPINSN	-	INSTRUMENT FOR RAPEPEN
RAPINST	-	INSTRUMENT FOR RAPEPET
RSEPEN	-	RESIDENTIAL SALES (NON-TEXAS):MWH
RSEPET	-	RESIDENTIAL SALES (TEXAS):MWH
TSEPE	-	TOTAL SYSTEM SALES:MWH
TSEPEN	-	TOTAL NON-TEXAS SALES:MWH

TSEPET	-	TOTAL TEXAS SALES:MWH
VCEEPE	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST ESTIMATE:000'S OF $
VCNG1	-	NATURAL GAS COST:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B:000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANT C:000'S OF $
VCPLNTD	-	VARIABLE COST FOR PLANT D:000'S OF $
VCPLNTE	-	VARIABLE COST FOR PLANT E:000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $
VCREPE	-	TOTAL FUEL AND PURCHASED POWER EXPENSE REPORTED: 000'S OF $

EXOGENOUS:

CCEPEN	-	COMMERCIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
CCEPET	-	COMMERCIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
CPITX	-	TEXAS CONSUMER PRICE INDEX
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A: MWH
GCPLNTB	-	GENERATION CAPABILITY OF PLANT B: MWH
GCPLNTC	-	GENERATION CAPABILITY OF PLANT C: MWH
GCPLNTD	-	GENERATION CAPABILITY OF PLANT D: MWH
GCPLNTE	-	GENERATION CAPABILITY OF PLANT E: MWH
GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES: MWH
ILFCSEPE	-	LOSS FACTOR: COMMERCIAL SALES
ILFISEPE	-	LOSS FACTOR: INDUSTRIAL SALES
ILFOSEPE	-	LOSS FACTOR: OTHER SALES
ILFRSEPE	-	LOSS FACTOR: RESIDENTIAL SALES
ILFWSEPE	-	LOSS FACTOR: WHOLESALE SALES
ISEPEN	-	INDUSTRIAL SALES (NON-TEXAS):MWH
ISEPET	-	INDUSTRIAL SALES (TEXAS):MWH
MATFCEPE	-	FOUR QUARTER MOVING AVERAGE OF TOTAL FIXED COST: 000'S OF $
OSEPEN	-	OTHER SALES (NON-TEXAS):MWH
OSEPET	-	OTHER SALES (TEXAS):MWH
RCDDINSN	-	INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL COOLING DEGREE DAYS
RCDDINST	-	INSTRUMENT FOR (TEXAS) RESIDENTIAL COOLING DEGREE DAYS
RCEPEN	-	RESIDENTIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS

RCEPET	-	RESIDENTIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
RHDDINSN	-	INSTRUMENT FOR (NON-TEXAS) RESIDENTIAL HEATING DEGREE DAYS
RHDDINST	-	INSTRUMENT FOR (TEXAS) RESIDENTIAL HEATING DEGREE DAYS
RPIEPEN	-	SERVICE AREA REAL PERSONAL INCOME (NON-TEXAS): BILLIONS OF $
RPIEPET	-	SERVICE AREA REAL PERSONAL INCOME (TEXAS):BILLIONS OF $
UFCNG1	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN NATURAL GAS PLANTS: 000'S OF $
UFCPLNTA	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT A: 000'S OF $ PER MWH
UFCPLNTB	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT B: 000'S OF $ PER MWH
UFCPLNTC	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT C: 000'S OF $ PER MWH
UFCPLNTD	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT D: 000'S OF $ PER MWH
UFCPLNTE	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT E: 000'S OF $ PER MWH
UFCPPC	-	UNIT COST OF PURCHASED POWER FRON NON-UTILITY SOURCES: 000'S OF $ PER MWH
WSEPEN	-	WHOLESALE SALE (NON-TEXAS):MWH
WSEPET	-	WHOLESALE SALE (TEXAS):MWH

IDENTITIES

```
RAPINST=(RAPEPET/CPITX)*RCEPET;
RAPINSN=(RAPEPEN/CPITX)*RCEPEN;

TSEPET=RSEPET+CSEPET+ISEPET+OSEPET+WSEPET;
TSEPEN=RSEPEN+CSEPEN+ISEPEN+OSEPEN+WSEPEN;
TSEPE=TSEPET+TSEPEN;

AFCEPE=MATFCEPE/
 (TSEPE+TSEPE(-1)+TSEPE(-2)+TSEPE(-3));

AVCREPE=VCREPE/TSEPE;

ACEPE = (AVCREPE + AFCEPE);

GENREPE = (RSEPET+RSEPEN) * ILFRSEPE +
 (CSEPET+CSEPEN) * ILFCSEPE +
 (ISEPET+ISEPEN) * ILFISEPE +
 (OSEPET+OSEPEN) * ILFISEPE +
 (WSEPET+WSEPEN) * ILFWSEPE;
```

```
PPCC = GENREPE-GCPPC;
PLNTAC = PPCC-GCPLNTA;
PLNTBC = PLNTAC-GCPLNTB;
PLNTCC = PLNTBC-GCPLNTC;
PLNTDC = PLNTCC-GCPLNTD;
PLNTEC = PLNTDC-GCPLNTE;

GRPPC = (PPCC>0)*GCPPC+(PPCC<0)*GENREPE;
VCPPC = GRPPC*UFCPPC/1000;
GRPLNTA = (PPCC>0)*( (PLNTAC>0)*GCPLNTA+(PLNTAC<=0)*PPCC);
VCPLNTA = GRPLNTA*UFCPLNTA/1000;
GRPLNTB = (PPCC>0)*(PLNTAC>0)*( (PLNTBC>0)*GCPLNTB+
 (PLNTBC<=0)*PLNTAC );
VCPLNTB = GRPLNTB*UFCPLNTB/1000;
GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*( (PLNTCC>0)*GCPLNTC+
 (PLNTCC<=0)*PLNTBC );
VCPLNTC = GRPLNTC*UFCPLNTC/1000;
GRPLNTD = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 ( (PLNTDC>0)*GCPLNTD+(PLNTDC<=0)*PLNTCC );
VCPLNTD = GRPLNTD*UFCPLNTD/1000;
GRPLNTE = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
 ( (PLNTEC>0)*GCPLNTE+(PLNTEC<=0)*PLNTDC );
VCPLNTE = GRPLNTE*UFCPLNTE/1000;
GRNGL = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
 (PLNTDC>0)*(PLNTEC>0)* PLNTEC ;
VCNGL = GRNGL*UFCNGL/1000;

VCEEPE =
 VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+
 VCPLNTE+VCNGL+VCPPC;
```

EQUATION ESTIMATES

<u>EQUATION 1: TEXAS RESIDENTIAL SALES</u>

RSEPET=a0+a1*RSEPET(-4)+a2*RAPINST(-1)+a3*RPIEPET+a4*RCDDINST+a5*RHDDINST

Number of observations: 56
Mean of dependent variable = 213108.
Std. dev. of dependent var. = 37548.1
Sum of squared residuals = .159719E+10
Variance of residuals = .319439E+08
Std. error of regression = 5651.89
R-squared = .979503
Adjusted R-squared = .977454
Durbin-Watson statistic = 2.03502
F-statistic (zero slopes) = 475.490
E'PZ*E = .766241E+08

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-21810.5	9834.28	-2.21781
RSEPET(-4)	.555134	.163839	3.38830
RAPINST(-1)	-.893748	.730921	-1.22277
RPIEPET	86329.5	30184.6	2.86005
RCDDINST	.347518E-03	.111518E-03	3.11626
RHDDINST	.229222E-03	.696441E-04	3.29133

EQUATION 2: NON TEXAS RESIDENTIAL SALES

RSEPEN=b0+b1*RSEPEN(-4)+b2*RAPINSN(-1)+b3*RPIEPEN+b4*RCDDINSN+b5*RHDDINSN

Number of observations: 56
Mean of dependent variable = 62218.5
Std. dev. of dependent var. = 10200.1
Sum of squared residuals = .121911E+09
Variance of residuals = .243822E+07
Std. error of regression = 1561.48
R-squared = .978710
Adjusted R-squared = .976581
Durbin-Watson statistic = 2.17746
F-statistic (zero slopes) = 459.384
E'PZ*E = .367322E+08

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-2885.13	2241.82	-1.28696
RSEPEN(-4)	.588005	.110371	5.32755
RAPINSN(-1)	-2.47984	1.44971	-1.71057
RPIEPEN	74819.1	24483.9	3.05585
RCDDINSN	.267272E-03	.660195E-04	4.04838
RHDDINSN	.249449E-03	.595445E-04	4.18929

EQUATION 3: TEXAS RESIDENTIAL PRICE

RAPEPET=c0+c1*ACEPE

Number of observations: 31
(Statistics based on transformed data)
Mean of dependent variable = .046531
Std. dev. of dependent var. = .010899
Sum of squared residuals = .619994E-03
Variance of residuals = .213791E-04
Std. error of regression = .462375E-02
R-squared = .827356
Adjusted R-squared = .821403
Durbin-Watson statistic = 1.95191
Rho (autocorrelation coef.) = .448673
Standard error of rho = .160513
t-statistic for rho = 2.79525
Log of likelihood function = 123.720

(Statistics based on original data)
Mean of dependent variable = .083023
Std. dev. of dependent var. = .019603
Sum of squared residuals = .619994E-03
Variance of residuals = .213791E-04
Std. error of regression = .462375E-02
R-squared = .946257
Adjusted R-squared = .944403
Durbin-Watson statistic = 1.95191

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.973974E-02	.644509E-02	1.51119
ACEPE	1.12070	.094069	11.9136

EQUATION 4: TEXAS COMMERCIAL PRICE

CAPEPET=d0+d1*ACEPE

Number of observations: 31
(Statistics based on transformed data)
Mean of dependent variable = .046747
Std. dev. of dependent var. = .012149
Sum of squared residuals = .108208E-02
Variance of residuals = .373132E-04
Std. error of regression = .610845E-02
R-squared = .756191
Adjusted R-squared = .747783
Durbin-Watson statistic = 1.76644
Rho (autocorrelation coef.) = .369272
Standard error of rho = .164282
t-statistic for rho = 2.24779
Log of likelihood function = 115.087
(Statistics based on original data)
Mean of dependent variable = .073323
Std. dev. of dependent var. = .018472
Sum of squared residuals = .108208E-02
Variance of residuals = .373132E-04
Std. error of regression = .610845E-02
R-squared = .894392
Adjusted R-squared = .890751
Durbin-Watson statistic = 1.76644

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.554907E-02	.737538E-02	.752378
ACEPE	1.03414	.108099	9.56654

EQUATION 5: TEXAS INDUSTRIAL PRICE

IAPEPET=c0+c1*ACEPE

Number of observations: 31
(Statistics based on transformed data)
Mean of dependent variable = .023085
Std. dev. of dependent var. = .534067E-02
Sum of squared residuals = .295273E-03
Variance of residuals = .101818E-04
Std. error of regression = .319090E-02
R-squared = .656540
Adjusted R-squared = .644697
Durbin-Watson statistic = 1.88881
Rho (autocorrelation coef.) = .586604
Standard error of rho = .145458
t-statistic for rho = 4.03282
Log of likelihood function = 135.218
(Statistics based on original data)
Mean of dependent variable = .054523
Std. dev. of dependent var. = .012092
Sum of squared residuals = .295273E-03
Variance of residuals = .101818E-04
Std. error of regression = .319090E-02
R-squared = .932712
Adjusted R-squared = .930392
Durbin-Watson statistic = 1.88881

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.012212	.600300E-02	2.03432
ACEPE	.646869	.086595	7.47007

EQUATION 6: NON TEXAS RESIDENTIAL PRICE

RAPEPEN=f0+f1*ACEPE

Number of observations: 31
(Statistics based on transformed data)
Mean of dependent variable = .043590
Std. dev. of dependent var. = .011909
Sum of squared residuals = .702231E-03
Variance of residuals = .242149E-04
Std. error of regression = .492086E-02
R-squared = .835458
Adjusted R-squared = .829784
Durbin-Watson statistic = 1.65357
Rho (autocorrelation coef.) = .429820
Standard error of rho = .159614
t-statistic for rho = 2.69287
Log of likelihood function = 121.789
(Statistics based on original data)
Mean of dependent variable = .075205

Std. dev. of dependent var. = .020283
Sum of squared residuals = .702231E-03
Variance of residuals = .242149E-04
Std. error of regression = .492086E-02
R-squared = .943142
Adjusted R-squared = .941181
Durbin-Watson statistic = 1.65357

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.162014E-02	.661894E-02	-.244773
ACEPE	1.17337	.096715	12.1322

EQUATION 7: NON TEXAS COMMERCIAL PRICE

CAPEPEN=g0+g1*ACEPE

Number of observations: 32
Mean of dependent variable = .068293
Std. dev. of dependent var. = .013680
Sum of squared residuals = .821392E-03
Variance of residuals = .273797E-04
Std. error of regression = .523256E-02
R-squared = .858607
Adjusted R-squared = .853894
Durbin-Watson statistic = 1.14509
F-statistic (zero slopes) = 181.901
E'PZ*E = .601623E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.019636	.369887E-02	5.30865
ACEPE	.752812	.055409	13.5864

EQUATION 8: TOTAL FUEL EXPENSE

VCREPE=h0+h1*VCEEPE

Number of observations: 55
(Statistics based on transformed data)
Mean of dependent variable = 10698.4
Std. dev. of dependent var. = 4007.28
Sum of squared residuals = .440296E+09
Variance of residuals = .830748E+07
Std. error of regression = 2882.27
R-squared = .493569
Adjusted R-squared = .484014
Durbin-Watson statistic = 2.25373
Rho (autocorrelation coef.) = .601455
Standard error of rho = .107725
t-statistic for rho = 5.58327
Log of likelihood function = -515.171

(Statistics based on original data)
Mean of dependent variable = 26489.6
Std. dev. of dependent var. = 5321.81
Sum of squared residuals = .440296E+09
Variance of residuals = .830748E+07
Std. error of regression = 2882.27
R-squared = .714877
Adjusted R-squared = .709497
Durbin-Watson statistic = 2.25373

Variable	Estimated Coefficient	Standard Error	t-statistic
C	15105.1	2028.73	7.44561
VCEEPE	.509055	.077148	6.59840

4-11 TEXAS NEW-MEXICO POWER COMPANY

MODEL: TNP

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCTNP	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRTNP	-	AVERAGE FUEL EXPENSES AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CAPINST	-	INSTRUMENT FOR CAPTNP
CAPTNP	-	COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
CSTNP	-	COMMERCIAL SALES:MWH
GENRTNP	-	GENERATION REQUIREMENTS:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPINST	-	INSTRUMENT FOR IAPTNP
IAPTNP	-	INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
ISTNP	-	INDUSTRIAL SALES:MWH
OAPINST	-	INSTRUMENT FOR OAPTNP
OAPTNP	-	OTHER RETAIL AVERAGE PRICE:000'S OF $ PER MWH
OSTNP	-	OTHER RETAIL SALES:MWH
PLNTAC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RAPINST	-	INSTRUMENT FOR RAPTNP
RAPTNP	-	RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
RSTNP	-	RESIDENTIAL SALES :MWH
TSTNP	-	TOTAL SYSTEM SALES:MWH
VCETNP	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE: 000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B: 000'S OF $
VCRTNP	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST REPORTED: 000'S OF $

EXOGENOUS:

CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CCTNP	-	COMMERCIAL CUSTOMERS :NUMBER OF CUSTOMERS
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A: MWH
ICDDTNP	-	INSTRUMENT FOR INDUSTRIAL COOLING DEGREE DAYS: NUMBER OF DAYS
ISDUM	-	DUMMY VARIABLE IN INDUSTRIAL SALES EQUATION
LFTNP	-	LOSS FACTOR
MATFCTNP	-	FOUR QUARTER MOVING AVERAGE OF TOTAL FIXED COSTS: 000'S OF $
OCDDTNP	-	INSTRUMENT FOR OTHER RETAIL SALES COOLING DEGREE DAYS
OHDDTNP	-	INSTRUMENT FOR OTHER RETAIL SALES HEATING DEGREE DAYS
OSDUM	-	DUMMY VARIABLE IN OTHER SALES EQUATION
PNGITNP	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS: $ PER MCF
POPTNP	-	POPULATION:000'S OF PERSONS
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RCTNP	-	RESIDENTIAL CUSTOMERS: NUMBER OF CUSTOMERS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPITNP	-	REAL PERSONAL INCOME(BILLIONS OF $)
UFCPLNTA	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT A:000'S OF $ PER MWH
UFCPLNTB	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT B: 000'S OF $ PER MWH
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES: 000'S OF $ PER MWH
WSTNP	-	WHOLESALE SALES:MWH

IDENTITIES

RAPINST=(RAPTNP(-4)/CPITX(-4))*RCTNP;
CAPINST=(CAPTNP(-4)/CPITX(-4))*CCTNP;
IAPINST=IAPTNP(-1)/PNGITNP(-1);
OAPINST=OAPTNP(-1)/CPITX(-1);

TSTNP=RSTNP+CSTNP+ISTNP+OSTNP+WSTNP;

AFCTNP=MATFCTNP/
(TSTNP+TSTNP(-1)+TSTNP(-2)+TSTNP(-3));

AVCRTNP=VCRTNP/TSTNP;

GENRTNP=TSTNP/(1-LFTNP)
PPCC = GENRTNP-GCPPC;
PLNTAC = PPCC-GCPLNTA;

GRPPC = (PPCC>0)*GCPPC+(PPCC<0)*GENRTNP;
VCPPC = GRPPC*UFCPPC/1000;
GRPLNTA = (PPCC>0)*((PLNTAC>0)*GCPLNTA+(PLNTAC<=0)*PPCC);
VCPLNTA = GRPLNTA*UFCPLNTA/1000;
GRPLNTB = (PPCC>0)*(PLNTAC>0)*PLNTAC;
VCPLNTB = GRPLNTB*UFCPLNTB/1000;

VCETNP =
VCPLNTA+VCPLNTB+VCPPC;

EQUATION ESTIMATES

EQUATION 1: RESIDENTIAL SALES

RSTNP=a0+a1*RSTNP(-1)+a2*RAPINST+a3*RPITNP+a4*RCDDINST+a5*RHDDINST

Number of observations: 52
Mean of dependent variable = 384330.
Std. dev. of dependent var. = 109317.
Sum of squared residuals = .749634E+11
Variance of residuals = .162964E+10
Std. error of regression = 40368.8
R-squared = .883349
Adjusted R-squared = .870669
Durbin-Watson statistic = 2.14684
F-statistic (zero slopes) = 65.5976
E'PZ*E = .311548E+10

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-175126.	63624.9	-2.75248
RSTNP(-1)	.418601	.121059	3.45784
RAPINST	-10.7654	7.26321	-1.48218
RPITNP	157662.	140274.	1.12396
RCDDINST	.261448E-02	.211217E-03	12.3782
RHDDINST	.213489E-02	.264341E-03	8.07628

EQUATION 2: COMMERCIAL SALES

CSTNP=b0+b1*CSTNP(-1)+b2*CAPINST+b3*POPTNP+b4*CCDDINST+b5*CHDDINST

Number of observations: 50
(Statistics based on transformed data)
Mean of dependent variable = 170976.
Std. dev. of dependent var. = 45669.3
Sum of squared residuals = .380126E+10
Variance of residuals = .863922E+08
Std. error of regression = 9294.74
R-squared = .962812
Adjusted R-squared = .958586
Durbin-Watson statistic = 1.75308
Rho (autocorrelation coef.) = .372618
Standard error of rho = .131237
t-statistic for rho = 2.83927
Log of likelihood function = -524.611
(Statistics based on original data)
Mean of dependent variable = 271122.
Std. dev. of dependent var. = 50568.6
Sum of squared residuals = .380126E+10
Variance of residuals = .863922E+08
Std. error of regression = 9294.74
R-squared = .969672
Adjusted R-squared = .966225
Durbin-Watson statistic = 1.75308

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-364173.	51404.3	-7.08448
CSTNP(-1)	.123909	.035023	3.53790
CAPINST	-42.6610	19.0746	-2.23653
POPTNP	1647.90	188.324	8.75035
CCDDINST	.304097E-02	.168804E-03	18.0149
CHDDINST	.493982E-03	.220027E-03	2.24509

EQUATION 3: INDUSTRIAL SALES

ISTNP=c0+c1*ISTNP(-4)+c2*IAPINST+c3*ISDUM+c4*ICDDTNP

Number of observations: 50
(Statistics based on transformed data)
Mean of dependent variable = 144509.
Std. dev. of dependent var. = 45696.5
Sum of squared residuals = .390764E+11
Variance of residuals = .868364E+09
Std. error of regression = 29468.0
R-squared = .620087
Adjusted R-squared = .586317
Durbin-Watson statistic = 2.27131
Rho (autocorrelation coef.) = .720802
Standard error of rho = .098025
t-statistic for rho = 7.35325
Log of likelihood function = -582.866
(Statistics based on original data)
Mean of dependent variable = 521930.

Std. dev. of dependent var. = 82208.5
Sum of squared residuals = .390764E+11
Variance of residuals = .868364E+09
Std. error of regression = 29468.0
R-squared = .882845
Adjusted R-squared = .872432
Durbin-Watson statistic = 2.27131

Variable	Estimated Coefficient	Standard Error	t-statistic
C	542863.	89711.5	6.05121
ISTNP(-4)	.244569	.164095	1.49041
IAPINST	-.769681E+07	.413759E+07	-1.86022
ISDUM	-145272.	24464.8	-5.93801
ICDDTNP	14.8958	7.16064	2.08023

EQUATION 4: OTHER RETAIL SALES

OSTNP=d0+d1*POPTNP+d2*OSDUM+d3*OCDDTNP+d4*OHDDTNP

Number of observations: 56
Mean of dependent variable = 23313.1
Std. dev. of dependent var. = 2535.01
Sum of squared residuals = .291175E+08
Variance of residuals = 570930.
Std. error of regression = 755.599
R-squared = .917618
Adjusted R-squared = .911157
Durbin-Watson statistic = 1.82451
F-statistic (zero slopes) = 142.017
Schwarz Bayes. Info. Crit. = 13.5209
Log of likelihood function = -447.982

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-13774.7	2074.13	-6.64120
POPTNP	94.9133	5.48627	17.3001
OSDUM	-2279.76	294.350	-7.74505
OCDDTNP	4.14542	.351504	11.7934
OHDDTNP	2.02359	.448729	4.50961

EQUATION 5: RESIDENTIAL AVERAGE PRICE

RAPTNP=c0+c1*AVCRTNP+c2*AFCTNP

Number of observations: 50
(Statistics based on transformed data)
Mean of dependent variable = .040225
Std. dev. of dependent var. = .791229E-02
Sum of squared residuals = .387900E-03
Variance of residuals = .825319E-05
Std. error of regression = .287284E-02

R-squared = .874767
Adjusted R-squared = .869438
Durbin-Watson statistic = 2.06881
Rho (autocorrelation coef.) = .442337
Standard error of rho = .126834
t-statistic for rho = 3.48754
Log of likelihood function = 223.223
(Statistics based on original data)
Mean of dependent variable = .071456
Std. dev. of dependent var. = .012433
Sum of squared residuals = .387900E-03
Variance of residuals = .825319E-05
Std. error of regression = .287284E-02
R-squared = .948823
Adjusted R-squared = .946645
Durbin-Watson statistic = 2.06881

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.439819E-02	.487171E-02	-.902803
AVCRTNP	1.20056	.096980	12.3795
AFCTNP	.653631	.058701	11.1349

EQUATION 6: COMMERCIAL AVERAGE PRICE

CAPTNP=f0+f1*AVCRTNP+f2*AFCTNP

Number of observations: 50
(Statistics based on transformed data)
Mean of dependent variable = .01652
Std. dev. of dependent var. = .525305E-02
Sum of squared residuals = .224167E-03
Variance of residuals = .476952E-05
Std. error of regression = .218392E-02
R-squared = .836699
Adjusted R-squared = .829750
Durbin-Watson statistic = 2.04800
Rho (autocorrelation coef.) = .757846
Standard error of rho = .092268
t-statistic for rho = 8.21354
Log of likelihood function = 236.932
(Statistics based on original data)
Mean of dependent variable = .065961
Std. dev. of dependent var. = .010247
Sum of squared residuals = .224167E-03
Variance of residuals = .476952E-05
Std. error of regression = .218392E-02
R-squared = .957054
Adjusted R-squared = .955226
Durbin-Watson statistic = 2.04800

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.423782E-03	.583832E-02	-.072586
AVCRTNP	1.05330	.090896	11.5879
AFCTNP	.572391	.090354	6.33501

EQUATION 7: INDUSTRIAL AVERAGE PRICE

IAPTNP=g0+g1*AVCRTNP+g2*AFCTNP

Number of observations: 56
Mean of dependent variable = .043320
Std. dev. of dependent var. = .936624E-02
Sum of squared residuals = .301968E-03
Variance of residuals = .569751E-05
Std. error of regression = .238695E-02
R-squared = .938221
Adjusted R-squared = .935890
Durbin-Watson statistic = 1.02350
F-statistic (zero slopes) = 396.926
E'PZ*E = .107475E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.230270E-02	.171155E-02	-1.34539
AVCRTNP	.924062	.036674	25.1968
AFCTNP	.205495	.026864	7.64952

EQUATION 8: OTHER RETAIL AVERAGE PRICE

OAPTNP=h0+h1*AVCRTNP+h2*AFCTNP

Number of observations: 50
(Statistics based on transformed data)
Mean of dependent variable = .018920
Std. dev. of dependent var. = .543196E-02
Sum of squared residuals = .253281E-03
Variance of residuals = .538895E-05
Std. error of regression = .232141E-02
R-squared = .829120
Adjusted R-squared = .821848
Durbin-Watson statistic = 1.96013
Rho (autocorrelation coef.) = .657908
Standard error of rho = .106504
t-statistic for rho = 6.17729
Log of likelihood function = 233.879
(Statistics based on original data)
Mean of dependent variable = .053565
Std. dev. of dependent var. = .011531
Sum of squared residuals = .253281E-03
Variance of residuals = .538895E-05
Std. error of regression = .232141E-02

R-squared = .961178
Adjusted R-squared = .959526
Durbin-Watson statistic = 1.96013

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.013231	.533559E-02	-2.47970
AVCRTNP	.958060	.095081	10.0762
AFCTNP	.698601	.072784	9.59822

EQUATION 9: TOTAL FUEL EXPENSE AND PURCHASED POWER COST

VCRTNP=i0+i1*VCETNP

Number of observations: 50
(Statistics based on transformed data)
Mean of dependent variable = 17151.3
Std. dev. of dependent var. = 10082.0
Sum of squared residuals = .158148E+10
Variance of residuals = .329475E+08
Std. error of regression = 5739.99
R-squared = .682517
Adjusted R-squared = .675903
Durbin-Watson statistic = 2.28148
Rho (autocorrelation coef.) = .673629
Standard error of rho = .104520
t-statistic for rho = 6.44496
Log of likelihood function = -502.687
(Statistics based on original data)
Mean of dependent variable = 51977.4
Std. dev. of dependent var. = 12342.1
Sum of squared residuals = .158148E+10
Variance of residuals = .329475E+08
Std. error of regression = 5739.99
R-squared = .791824
Adjusted R-squared = .787487
Durbin-Watson statistic = 2.28148

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-2743.95	8000.91	-.342955
VCETNP	1.34707	.185255	7.27143

4-12 CITY OF AUSTIN ELECTRIC UTILITY

MODEL: COA

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCCOA	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRCOA	-	AVERAGE FUEL EXPENSES AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CAPCOA	-	COMMERCIAL AVERAGE PRICE:000'S OF $ PER MWH
CAPINST	-	INSTRUMENT FOR CAPCOA
CSCOA	-	COMMERCIAL SALES:MWH
GENRCOA	-	GENERATION REQUIREMENTS:MWH
GRNG	-	GENERATION REQUIREMENTS FROM NATURAL GAS PLANT:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPCOA	-	INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
IAPINST	-	INSTRUMENT FOR IAPCOA
ISCOA	-	INDUSTRIAL SALES: MWH
MATFCCOA	-	FOUR QUARTER MOVING AVERAGE OF TOTAL SALES:MWH
OAPCOA	-	OTHER AVERAGE PRICE: 000'S OF DOLLARS PER MWH
OAPINST	-	INSTRUMENT FOR OAPCOA
OSCOA	-	OTHER SALES: MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RAPCOA	-	RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
RAPINST	-	INSTRUMENT FOR RAPCOA
RSCOA	-	RESIDENTIAL SALES:MWH
TSCOA	-	TOTAL SYSTEM SALES:MWH

VCECOA	-	TOTAL FUEL AND PURCHASED POWER EXPENSE ESTIMATE: 000'S OF $
VCNG	-	NATURAL GAS COST:000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANTA:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANTB:000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANTC:000'S OF $
VCPPC	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES:000'S OF $
VCRCOA	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST REPORTED: 000'S OF $

EXOGENOUS:

CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CCCOA	-	COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
CDDCOA	-	COOLING DEGREE DAYS
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLNTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLNTC	-	GENERATION CAPABILITY OF PLANT C:MWH
GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
HDDCOA	-	HEATING DEGREE DAYS
LFCOA	-	LOSS FACTOR
MATFCCOA	-	MOVING AVERAGE OF FIXED COST: 000'S $
NAGCOA	-	NON-AGRICULTURAL EMPLOYMENT: 000'S OF PERSONS
PNGICOA	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS: $ PER MCF
Q1	-	DUMMY VARIABLE FOR FIRST QUARTER
Q3	-	DUMMY VARIABLE FOR THIRD QUARTER
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RCCOA	-	RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPICOA	-	REAL PERSONAL INCOME: BILLIONS OF $
UFCNG	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN NATURAL GAS PLANT:000'S OF $
UFCPLNTA	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT A:000'S OF $ PER MWH
UFCPLNTB	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT B:000'S OF $ PER MWH

UFCPLNTC	-	FUEL COST TO PRODUCE ONE MWH OF ELECTRICITY IN PLANT C:000'S OF $ PER MWH
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES: 000'S OF $ PER MWH

IDENTITIES

RAPINST = (RAPCOA(-3)/CPITX(-3))*RCCOA
CAPINS = CAPCOA(-3)/CPITX(-3))*CCCOA
IAPINST = IAPCOA(-3)/PNGICOA(-3)
OAPINST = OAPCOA/CPITX
TSCOA = RSCOA+CSCOA+ISCOA+OSCOA

AFCCOA = MATFCCOA/(TSCOA+TSCOA(-1)+ TSCOA(-2)+TSCOA(-3))

AVCRCOA = VCRCOA/TSCOA
GENRCOA = TSCOA/(1-LFCOA)
PPCC = GENRCOA-GCPPC
PLNTAC = PPCC-GCPLNTA
PLNTBC = PLNTAC-GCPLNTB
PLNTCC = PLNTBC-GCPLNTC
GRPPC = (PPCC>0)*GCPPC+(PPCC<=0)*GENRCOA;
VCPPC = GRPPC*UFCPPC/1000
GRPLNTA = (PPCC>0)*((PLNTAC>0)*GCPLNTA+ (PLNTAC<=0)*PPCC)
VCPLNTA = GRPLNTA*UFCPLNTA/1000
GRPLNTB = (PPCC>0)*(PLNTAC>0)*((PLNTBC>0)*GCPLNTB+ (PLNTBC<=0)*PLNTAC)
VCPLNTB = GRPLNTB*UFCPLNTB/1000
GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*((PLNTCC>0)*GCPLNTC+(PLNTCC<=0)* PLNTBC)
VCPLNTC = GRPLNTC*UFCPLNTC/1000
GRNG = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)* PLNTCC
VCNG = GRNG*UFCNG/1000

VCECOA = VCPPC+VCPLNTA+VCPLNTB+VCPLNTC+ VCNG

EQUATION 1: RESIDENTIAL SALES

RSCOA = a0 +a1*RAPINST + a2*RPICOA(-4) + a3* RCDDINST + a4*RHDDINST

Number of observations: 48
Mean of dependent variable = 508778.
Std. dev. of dependent var. = 163621.
Sum of squared residuals = .995354E+11
Variance of residuals = .231478E+10
Std. error of regression = 48112.1
R-squared = .920899
Adjusted R-squared = .913541
Durbin-Watson statistic = 2.30617

F-statistic (zero slopes) = 125.147
E'PZ*E = .348751E+11

Variable	Estimated Coefficient	Standard Error	t-statistic
C	13589.3	49193.2	.276243
RAPINST	-16.6164	6.30104	-2.63709
RPICOA(-4)	225007.	49533.2	4.54256
RCDDINST	.165972E-02	.115585E-03	14.3593
RHDDINST	.152784E-02	.191763E-03	7.96732

EQUATION 2: COMMERCIAL SALES

CSCOA = b0 + b1*CAPINST + b2*RPICOA +b3*CCDDINST + b4*CHDDINST

Number of observations: 49
Mean of dependent variable = 614435.
Std. dev. of dependent var. = 155457.
Sum of squared residuals = .300497E+11
Variance of residuals = .682949E+09
Std. error of regression = 26133.3
R-squared = .974100
Adjusted R-squared = .971745
Durbin-Watson statistic = 1.77566
F-statistic (zero slopes) = 413.635
E'PZ*E = .195693E+11

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-78472.7	26831.8	-2.92461
CAPINST	-139.253	30.5855	-4.55292
RPICOA	610507.	26673.8	22.8879
CCDDINST	.552529E-02	.518049E-03	10.6656
CHDDINST	.337534E-02	.832548E-03	4.05423

EQUATION 3: INDUSTRIAL SALES

ISCOA = c0+c1*IAPINST+c2*RPICOA*c3*CDDCOA

Number of observations: 46
(Statistics based on transformed data)
Mean of dependent variable = 41095.3
Std. dev. of dependent var. = 16354.1
Sum of squared residuals = .214670E+10
Variance of residuals = .511119E+08
Std. error of regression = 7149.26
R-squared = .822043
Adjusted R-squared = .809331
Durbin-Watson statistic = 1.87558
Rho (autocorrelation coef.) = .685191

Standard error of rho = .107391
t-statistic for rho = 6.38033
Log of likelihood function = -471.418
(Statistics based on original data)
Mean of dependent variable = 124049.
Std. dev. of dependent var. = 39889.3
Sum of squared residuals = .214670E+10
Variance of residuals = .511119E+08
Std. error of regression = 7149.26
R-squared = .970090
Adjusted R-squared = .967954
Durbin-Watson statistic = 1.87558

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-23357.0	32230.7	-.724681
IAPINST	-.255769E+07	694216.	-3.68428
RPICOA	162321.	18864.2	8.60470
CDDCOA	11.4531	1.35120	8.47624

EQUATION 4: OTHER SALES

OSCOA = d0+d1*OAPINST+d2*NAGCOA+d3*CDDCOA+d4*HDDCOA

Number of observations: 46
(Statistics based on transformed data)
Mean of dependent variable = 21702.6
Std. dev. of dependent var. = 4522.65
Sum of squared residuals = .261302E+09
Variance of residuals = .637321E+07
Std. error of regression = 2524.52
R-squared = .716114
Adjusted R-squared = .688418
Durbin-Watson statistic = 1.73054
Rho (autocorrelation coef.) = .416491
Standard error of rho = .134045
t-statistic for rho = 3.10709
Log of likelihood function = -422.980
(Statistics based on original data)
Mean of dependent variable = 36918.1
Std. dev. of dependent var. = 6271.85
Sum of squared residuals = .261302E+09
Variance of residuals = .637321E+07
Std. error of regression = 2524.52
R-squared = .852466
Adjusted R-squared = .838072
Durbin-Watson statistic = 1.73054

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-1046.99	6358.69	-.164656
OAPINST	-156676.	60968.1	-2.56980
NAGCOA	161.778	19.5517	8.27435

CDDCOA	6.18511	.990107	6.24690
HDDCOA	5.59613	1.57505	3.55298

EQUATION 5: RESIDENTIAL AVERAGE PRICE

RAPCOA = e0+e1*AVCRCOA(-4)+e2*AFCCOA+e3*Q1+e4*Q3

Number of observations: 46
(Statistics based on transformed data)
Mean of dependent variable = .024158
Std. dev. of dependent var. = .823476E-02
Sum of squared residuals = .662335E-03
Variance of residuals = .161545E-04
Std. error of regression = .401927E-02
R-squared = .784597
Adjusted R-squared = .763582
Durbin-Watson statistic = 1.81355
Rho (autocorrelation coef.) = .605920
Standard error of rho = .116039
t-statistic for rho = 5.22167
Log of likelihood function = 191.142
(Statistics based on original data)
Mean of dependent variable = .061034
Std. dev. of dependent var. = .871670E-02
Sum of squared residuals = .662335E-03
Variance of residuals = .161545E-04
Std. error of regression = .401927E-02
R-squared = .806939
Adjusted R-squared = .788104
Durbin-Watson statistic = 1.81355

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.346388E-02	.013252	.261376
AVCRCOA(-4)	.423346	.119417	3.54511
AFCCOA	1.03365	.247514	4.17614
Q1	-.590883E-02	.106596E-02	-5.54319
Q3	.965269E-02	.100936E-02	9.56320

EQUATION 6: COMMERCIAL AVERAGE PRICE

CAPCOA = f0+f1*CAPCOA(-1)+f2*AVCRCOA+f3*AFCCOA

Number of observations: 47
(Statistics based on transformed data)
Mean of dependent variable = .025466
Std. dev. of dependent var. = .447749E-02
Sum of squared residuals = .721055E-03
Variance of residuals = .167687E-04
Std. error of regression = .409496E-02
R-squared = .234519
Adjusted R-squared = .181114

Durbin-Watson statistic = 2.07690
Rho (autocorrelation coef.) = .611432
Standard error of rho = .115423
t-statistic for rho = 5.29733
Log of likelihood function = 193.806
(Statistics based on original data)
Mean of dependent variable = .065032
Std. dev. of dependent var. = .660570E-02
Sum of squared residuals = .721055E-03
Variance of residuals = .167687E-04
Std. error of regression = .409496E-02
R-squared = .641849
Adjusted R-squared = .616862
Durbin-Watson statistic = 2.07690

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.447937E-02	.019583	.228739
CAPCOA(-1)	.412501	.144110	2.86241
AVCRCOA	.421960	.128361	3.28728
AFCCOA	.520328	.270300	1.92500

EQUATION 7: INDUSTRIAL AVERAGE PRICE

IAPCOA = g0+g1*IAPCOA(-1)+g2*AVCRCOA+g3*AFCCOA

Number of observations: 49
Mean of dependent variable = .056460
Std. dev. of dependent var. = .922281E-02
Sum of squared residuals = .593160E-03
Variance of residuals = .131813E-04
Std. error of regression = .363061E-02
R-squared = .857923
Adjusted R-squared = .848451
Durbin-Watson statistic = 1.78776
F-statistic (zero slopes) = 88.2495
E'PZ*E = .279760E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.305632E-02	.781349E-02	-.391159
IAPCOA(-1)	.895631	.064753	13.8316
AVCRCOA	.172023	.076271	2.25541
AFCCOA	.098724	.123937	.796562

EQUATION 8: OTHER AVERAGE PRICE

OAPCOA=h0+h1*OAPCOA(-1)*h2*AVCRCOA+h3*AFCCOA

Number of observations: 47
(Statistics based on transformed data)
Mean of dependent variable = .028178

Std. dev. of dependent var. = .010646
Sum of squared residuals = .493371E-02
Variance of residuals = .114737E-03
Std. error of regression = .010712
R-squared = .122475
Adjusted R-squared = .061252
Durbin-Watson statistic = 1.83090
Rho (autocorrelation coef.) = .672760
Standard error of rho = .107920
t-statistic for rho = 6.23389
Log of likelihood function = 148.612
(Statistics based on original data)
Mean of dependent variable = .085080
Std. dev. of dependent var. = .015929
Sum of squared residuals = .493371E-02
Variance of residuals = .114737E-03
Std. error of regression = .010712
R-squared = .583030
Adjusted R-squared = .553939
Durbin-Watson statistic = 1.83090

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.048357	.047849	-1.01062
OAPCOA(-1)	.419634	.174007	2.41159
AVCRCOA	1.09339	.368742	2.96517
AFCCOA	1.57378	.771217	2.04064

EQUATION 9: FUEL COST AND PURCHASE POWER EXPENSE

VCRCOA = i0+i1*VCECOA

Number of observations: 49
Mean of dependent variable = 33876.7
Std. dev. of dependent var. = 13068.7
Sum of squared residuals = .171227E+10
Variance of residuals = .364313E+08
Std. error of regression = 6035.83
R-squared = .804006
Adjusted R-squared = .799836
Durbin-Watson statistic = 2.18235
F-statistic (zero slopes) = 178.025
E'PZ*E = .482415E+09

Variable	Estimated Coefficient	Standard Error	t-statistic
C	165.791	2899.72	.057175
VCECOA	1.02876	.084488	12.1764

4-13 BRAZOS ELECTRIC POWER COOPERATIVE

MODEL: BEPC

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCBEP	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AVCRBEP	-	AVERAGE FUEL EXPENSES AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CAPBEP	-	AVERAGE ELECTRICITY PRICE FOR THE COMMERCIAL CUSTOMERS OF BEPC MEMBER COOPERATIVES:000'S OF $ PER MWH
CAPINST	-	INSTRUMENT FOR CAPBEP
CSBEP	-	COMMERCIAL SALES OF BEPC MEMBER COOPERATIVES:MWH
GENRBEP	-	GENERATION REQUIREMENTS FOR BEPC SYSTEM:MWH
GRPLNTA	-	GENERATION REQUIREMENT FROM PLANT A:MWH
GRPLNTB	-	GENERATION REQUIREMENT FROM PLANT B:MWH
GRPLNTC	-	GENERATION REQUIREMENT FROM PLANT C:MWH
GRPLNTD	-	GENERATION REQUIREMENT FROM PLANT D:MWH
GRPPC	-	GENERATION REQUIREMENTS FROM COGENERATORS:MWH
IAPBEP	-	AVERAGE ELECTRICITY PRICE FOR THE INDUSTRIAL CUSTOMERS OF BEPC'S MEMBER COOPERATIVES:000'S OF $ PER MWH
IAPINST	-	INSTRUMENT FOR IAPBEP
ISBEP	-	INDUSTRIAL SALES OF BEPC MEMBER COOPERATIVES:MWH
MATSBEP	-	FOUR QUARTER MOVING AVERAGE OF TSBEP
OSBEP	-	OTHER (IRRIGATION AND OTHER) SALES OF BEPC MEMBER COOPERATIVES:MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PPCC	-	CONDITIONAL VARIABLE
RAPBEP	-	AVERAGE ELECTRICITY PRICE FOR RESIDENTIAL CUSTOMERS OF BEPC MEMBERS:000'S OF $ PER MWH
RAPINST	-	INSTRUMENT FOR RAPBEP
RSBEP	-	RESIDENTIAL SALES OF BEPC MEMBER COOPERATIVES:MWH
TSBEP	-	BRAZOS' TOTAL SALES (AT THE DISTRIBUTION POINTS):MWH
TSBEPSY	-	TOTAL SALES IN BEPC SYSTEM ONLY: MWH

TSOWBEP	-	TOTAL SALES TO BEPC'S OTHER (OTHER THAN THE MEMBER COOPERATIVES) WHOLESALE CUSTOMERS (AT THE DISTRIBUTION POINTS): MWH
TVCRBEP	-	TOTAL FUEL AND PURCHASED POWER EXPENSE REPORTED: 000'S OF $
VCEBEP	-	FUEL AND PURCHASED POWER EXPENSE ESTIMATE FOR BEPC SYSTEM ONLY: 000'S OF $
VCPLNTA	-	VARIABLE COST FOR PLANT A:000'S OF $
VCPLNTB	-	VARIABLE COST FOR PLANT B:000'S OF $
VCPLNTC	-	VARIABLE COST FOR PLANT C:000'S OF $
VCEPNTD	-	VARIABLE COST FOR PLANT D:000'S OF $
VCPPC	-	PURCHASED POWER COST FROM COGENERATORS: 000'S OF $
VCRBEP	-	FUEL EXPENSE AND PURCHASED POWER COST REPORTED FOR BEPC SYSTEM ONLY: 000'S OF $
WAPBEP	-	WHOLESALE AVERAGE PRICE:000'S OF $

EXOGENOUS:

ADJMF	-	ADJUSTMENT FACTOR TO ADJUST THE SUM TOTAL OF THE SALES OF INDIVIDUAL CUSTOMERS DATA (PLUS DISTRIBUTION LOSSES) TO THE TOTAL WHOLESALE SALES DATA
BEPSY	-	PORTION OF TOTAL BRAZOS LOAD SERVED BY BEPC TRANSMISSION AND GENERATION SYSTEM: RATIO
CCBEP	-	NUMBER OF COMMERCIAL CUSTOMERS OF BEPC MEMBER COOPERATIVES
CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CDDBEP	-	COOLING DEGREE DAYS IN BEPC SERVICE AREA
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
GCPLNTA	-	GENERATION CAPABILITY OF PLANT A:MWH
GCPLNTB	-	GENERATION CAPABILITY OF PLANT B:MWH
GCPLNTC	-	GENERATION CAPABILITY OF PLANT C:MWH
GCPPC	-	GENERATION CAPABILITY OF PURCHASED POWER FROM COGENERATORS:MWH
HDDBEP	-	HEATING DEGREE DAYS IN BEPC SERVICE AREA
IDLFCS	-	DISTRIBUTION LOSS FACTOR:COMMERCIAL SALES OF MEMBER COOPERATIVES
IDLFIS	-	DISTRIBUTION LOSS FACTOR:INDUSTRIAL SALES OF MEMBER COOPERATIVES
IDLFOS	-	DISTRIBUTION LOSS FACTOR:OTHER SALES OF MEMBER COOPERATIVES
IDLFRS	-	DISTRIBUTION LOSS FACTOR:RESIDENTIAL SALES OF MEMBER COOPERATIVES
ITLFBEP	-	TRANSMISSION LOSS FACTOR

MATFCBEP	-	FOUR QUARTER MOVING AVERAGE OF FIXED COSTS:000'S OF $
NAGBEP	-	NON-AGRICULTURAL EMPLOYMENT IN BEPC SERVICE AREA: 000'S OF PERSONS
PNGCBEP	-	PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS IN BEPC SERVICE AREA: $ PER MCF
PNGIBEP	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS IN BEPC SERVICE AREA: $ PER MCF
PNGRBEP	-	PRICE OF NATURAL GAS TO RESIDENTIAL CUSTOMERS IN BEPC SERVICE AREA: $ PER MCF
Q1	-	QUARTERLY DUMMY VARIABLE
Q2	-	QUARTERLY DUMMY VARIABLE
Q3	-	QUARTERLY DUMMY VARIABLE
RCBEP	-	NUMBER OF RESIDENTIAL CUSTOMERS OF BEPC MEMBER COOPERATIVES
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPIBEP	-	REAL PERSONAL INCOME:BILLIONS OF $
TSOWD1	-	DUMMY VARIABLE IN THE TSOWBEP EQUATION
UFCPLNTA	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRCITY IN PLANT A:000'S OF $
UFCPLNTB	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRCITY IN PLANT B:000'S OF $
UFCPLNTC	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRCITY IN PLANT C:000'S OF $
UFCPLNTD	-	VARIABLE COST TO PRODUCE ONE MWH OF ELECTRCITY IN PLANT D:000'S OF $
UFCPPC	-	UNIT COST OF PURCHASED POWER FROM COGENERATORS: 000'S OF $
VCRD1	-	DUMMY VARIABLE IN VCRBEP EQUATION
VCRD2	-	DUMMY VARIA BL E IN VCRBEP EQUATION
VCRD3	-	DUMMY VARIABLE IN VCRBEP EQUATION
VCRISO	-	PURCHASED POWER COST AT THE ISOLATED METERING POINTS: 000'S OF $

IDENTITIES

RAPINST=(RAPBEP(-1)/PNGRBEP(-1))*RCBEP
CAPINST=(CAPBEP(-4)/PNGCBEP(-4))*CCBEP
IAPINST=(IAPBEP(-2)/PNGIBEP(-2))

TSBEP = (RSBEP * IDLFRS + CSBEP * IDLFCS +
ISBEP*IDLFIS+OSBEP*IDLFOS + TSOWBEP)*ADJMF

MATSBEP = TSBEP+TSBEP(-1)+TSBEP(-2)+TSBEP(-3)

AFCBEP = MATFCBEP/MATSBEP

TVCRBEP = VCRBEP+VCRISO

AVCRBEP = TVCRBEP/TSBEP

TSBEPSY = TSBEP*BEPSY

GENRBEP = TSBEPSY*ITLFBEP

PPCC = GENRBEP-GCPPC

PLNTAC = PPCC-GCPLNTA

PLNTBC = PLNTAC-GCPLNTB

PLNTCC = PLNTBC-GCPLNTC

GRPPC = (PPCC>0)*GCPPC+(PPCC<0)*GENRBEP

VCPPC = GRPPC*UFCPPC/1000

GRPLNTA = (PPCC>0)*((PLNTAC>0)*GCPLNTA+(PLNTAC<0)*PPCC)

VCPLNTA = GRPLNTA*UFCPLNTA/1000

GRPLNTB = (PPCC>0)*(PLNTAC>0)*
((PLNTBC>0)*GCPLNTB+(PLNTBC<0)*PLNTAC)

VCPLNTB = GRPLNTB*UFCPLNTB/1000

GRPLNTC = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*((PLNTCC>0)*GCPLNTC+(PLNTCC<0)*
PLNTBC)

VCPLNTC = GRPLNTC*UFCPLNTC/1000

GRPLNTD = (PPCC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*PLNTCC

VCPLNTD = GRPLNTD*UFCPLNTD/1000

VCEBEP=VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+VCPPC

EQUATION ESTIMATES

<u>EQUATION 1: RESIDENTIAL SALES</u>

RSBEP = a0+a1*RSBEP(-4)+a2*RAPINST+a3*RPIBEP+a4*RCDDINST+a5*RHDDINST

Number of observations: 48
Mean of dependent variable = 442267.

Std. dev. of dependent var. = 135811.
Sum of squared residuals = .245330E+11
Variance of residuals = .584118E+09
Std. error of regression = 24168.5
R-squared = .971786
Adjusted R-squared = .968428
Durbin-Watson statistic = 1.81370
F-statistic (zero slopes) = 288.424
E'PZ*E = .104378E+11

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-28395.4	49703.7	-.571293
RSBEP(-4)	.818135	.070711	11.5701
RAPINST	-27.3198	24.3975	-2.11978
RPIBEP	58617.1	27564.1	2.12658
RCDDINST	.510399E-03	.140012E-03	3.64539
RHDDINST	.502960E-03	.144791E-03	3.47369

EQUATION 2:.COMMERCIAL SALES

CSBEP = b0+b1*CAPINST+b2*NAGBEP+b3*CCDDINST+b4*CHDDINST

Number of observations: 46
(Statistics based on transformed data)
Mean of dependent variable = 32768.2
Std. dev. of dependent var. = 11723.6
Sum of squared residuals = .101934E+10
Variance of residuals = .248619E+08
Std. error of regression = 4986.17
R-squared = .835200
Adjusted R-squared = .819122
Durbin-Watson statistic = 2.33524
Rho (autocorrelation coef.) = .819268
Standard error of rho = .084545
t-statistic for rho = 9.69033
Log of likelihood function = -454.288
(Statistics based on original data)
Mean of dependent variable = 173678.
Std. dev. of dependent var. = 26561.1
Sum of squared residuals = .101934E+10
Variance of residuals = .248619E+08
Std. error of regression = 4986.17
R-squared = .967905
Adjusted R-squared = .964774
Durbin-Watson statistic = 2.33524

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-5050.47	41258.7	-.122410
CAPINST	-31.5735	34.9953	-1.902220
NAGBEP	807.458	191.501	4.21647
CCDDINST	.991466E-03	.799722E-04	12.3976

CHDDINST .716824E-03 .875783E-04 8.18495

EQUATION 3: INDUSTRIAL SALES

ISBEP = c0+c1*ISBEP(-1)+c2*IAPINST+c3*NAGBEP(-4)+c4*CDDBEP

Number of observations: 32
Mean of dependent variable = 90704.9
Std. dev. of dependent var. = 42481.9
Sum of squared residuals = .133289E+10
Variance of residuals = .493664E+08
Std. error of regression = 7026.13
R-squared = .976450
Adjusted R-squared = .972961
Durbin-Watson statistic = 1.83981
F-statistic (zero slopes) = 276.570
E'PZ*E = .237251E+09

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-13809.2	26682.5	-.517536
ISBEP(-1)	.908274	.099789	9.10198
IAPINST	-.162780E+07	.116496E+07	-1.79730
NAGBEP(-4)	192.687	163.018	1.18200
CDDBEP	11.2891	1.99515	5.65827

EQUATION 4: OTHER RETAIL SALES

OSBEP = d0+d1*CDDBEP+d2*Q1+d3*Q2+d4*Q3

Number of observations: 49
(Statistics based on transformed data)
Mean of dependent variable = 5590.38
Std. dev. of dependent var. = 7631.48
Sum of squared residuals = .217248E+09
Variance of residuals = .493746E+07
Std. error of regression = 2222.04
R-squared = .922286
Adjusted R-squared = .915221
Durbin-Watson statistic = 2.06407
Rho (autocorrelation coef.) = .316024
Standard error of rho = .135536
t-statistic for rho = 2.33166
Log of likelihood function = -444.494
(Statistics based on original data)
Mean of dependent variable = 8320.30
Std. dev. of dependent var. = 7094.85
Sum of squared residuals = .217248E+09
Variance of residuals = .493746E+07
Std. error of regression = 2222.04
R-squared = .910091
Adjusted R-squared = .901918

Durbin-Watson statistic = 2.06407

Variable	Estimated Coefficient	Standard Error	t-statistic
C	5463.38	921.633	5.92794
CDDBEP	9.14078	3.69708	2.47243
Q1	-3931.01	931.216	-4.22137
Q2	-8180.32	2588.31	-3.16048
Q3	-880.690	5420.84	-.162464

EQUATION 5: TOTAL OTHER SALES

TSOWBEP = c0+c1*TSOWD1+c2*NAGBEP+c3*CDDBEP+c4*HDDBEP

Number of observations: 52
Mean of dependent variable = 71923.7
Std. dev. of dependent var. = 20524.5
Sum of squared residuals = .157385E+10
Variance of residuals = .334863E+08
Std. error of regression = 5786.73
R-squared = .926781
Adjusted R-squared = .920549
Durbin-Watson statistic = 1.79547
F-statistic (zero slopes) = 148.644
E'PZ*E = .480407E+09

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-114050.	10179.3	-11.2041
TSOWD1	-22638.3	2671.79	-8.47308
NAGBEP	791.009	47.9124	16.5095
CDDBEP	33.4404	2.60734	12.8255
HDDBEP	15.9223	2.72673	5.83934

EQUATION 6: WHOLESALE AVERAGE PRICE

WAPBEP = f0+f1*AVCRBEP+f2*AFCBEP

Number of observations: 33
Mean of dependent variable = .047669
Std. dev. of dependent var. = .439920E-02
Sum of squared residuals = .113158E-03
Variance of residuals = .377195E-05
Std. error of regression = .194215E-02
R-squared = .818520
Adjusted R-squared = .806422
Durbin-Watson statistic = 1.71257
F-statistic (zero slopes) = 67.0922
E'PZ*E = .479636E-04

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.027428	.176003E-02	15.5836
AVCRBEP	.328077	.072826	4.50492
AFCBEP	.428972	.073397	5.84453

EQUATION 7: RESIDENTIAL AVERAGE PRICE

RAPBEP = g0+g1*WAPBEP

Number of observations: 52
Mean of dependent variable = .068865
Std. dev. of dependent var. = .012812
Sum of squared residuals = .381890E-03
Variance of residuals = .763780E-05
Std. error of regression = .276366E-02
R-squared = .954630
Adjusted R-squared = .953722
Durbin-Watson statistic = 1.64131
F-statistic (zero slopes) = 1045.98
E'PZ*E = .229396E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	-.117254E-02	.220403E-02	-.531998
WAPBEP	1.62163	.050254	32.2684

EQUATION 8: COMMERCIAL AVERAGE PRICE

CAPBEP = h0+h1*WAPBEP

Number of observations: 50
(Statistics based on transformed data)
Mean of dependent variable = .023798
Std. dev. of dependent var. = .397661E-02
Sum of squared residuals = .190465E-03
Variance of residuals = .396803E-05
Std. error of regression = .199199E-02
R-squared = .760772
Adjusted R-squared = .755788
Durbin-Watson statistic = 2.33805
Rho (autocorrelation coef.) = .663264
Standard error of rho = .105838
t-statistic for rho = 6.26680
Log of likelihood function = 241.005
(Statistics based on original data)
Mean of dependent variable = .069887
Std. dev. of dependent var. = .969180E-02
Sum of squared residuals = .190465E-03
Variance of residuals = .396803E-05
Std. error of regression = .199199E-02
R-squared = .958740

Adjusted R-squared = .957880
Durbin-Watson statistic = 2.33805

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.016142	.474656E-02	3.40073
WAPBEP	1.22770	.105191	11.6712

EQUATION 9: INDUSTRIAL AVERAGE PRICE

IAPBEP = i0+i1*WAPBEP

Number of observations: 52
Mean of dependent variable = .050232
Std. dev. of dependent var. = .948487E-02
Sum of squared residuals = .649704E-03
Variance of residuals = .129941E-04
Std. error of regression = .360473E-02
R-squared = .858417
Adjusted R-squared = .855585
Durbin-Watson statistic = .891370
F-statistic (zero slopes) = 303.092
E'PZ*E = .498708E-03

Variable	Estimated Coefficient	Standard Error	t-statistic
C	.159590E-02	.287479E-02	.555134
WAPBEP	1.12612	.065549	17.1799

EQUATION 10: TOTAL FUEL EXPENSE AND PURCHASED POWER COST

VCRBEP = j0+j1*VCEBEP+j2*VCRD1+j3*VCRD2+j4*VCRD3+j5*Q1+j6*Q2+j7*Q3

Number of observations: 52
Mean of dependent variable = 17733.8
Std. dev. of dependent var. = 5288.41
Sum of squared residuals = .110893E+09
Variance of residuals = .252029E+07
Std. error of regression = 1587.54
R-squared = .922254
Adjusted R-squared = .909885
Durbin-Watson statistic = 2.40592
F-statistic (zero slopes) = 74.5629
E'PZ*E = .273343E+08

Variable	Estimated Coefficient	Standard Error	t-statistic
C	750.817	1227.06	.611882
VCEBEP	.989042	.085012	11.6341
VCRD1	8997.92	709.010	12.6908
VCRD2	3868.37	753.692	5.13256
VCRD3	1115.95	856.795	1.30247

Q1	-945.341	642.032	-1.47242
Q2	1830.22	657.855	2.78210
Q3	442.681	773.665	.572187

LONG-TERM ELECTRIC PEAK DEMAND

AND CAPACITY RESOURCE FORECAST

FOR TEXAS

1992

TECHNICAL APPENDIX

TO

RESOURCE PLAN

APRIL 1993

THE PUBLIC UTILITY COMMISSION OF TEXAS

LONG-TERM ELECTRIC PEAK DEMAND AND CAPACITY RESOURCE FORECAST FOR TEXAS, 1992

RESOURCE PLANNING ANALYSIS

Prepared by

The University of Texas at Austin
Center for Energy Studies

for the

Public Utility Commission of Texas

January 1993

PROJECT STAFF

Faculty and Professional Staff:

Armando de Leon
Steve Nichols
Jay Zarnikau

Research Assistants:

Gordon Alexander
Hicham Badawi
Andrew Berner
Daniel Bullock
Jason Duncan
Umamahesh Ganti
Sid Guermouche
Balho Kim
Alex MacGregor
Raymond Mason
Suraj Mukundarajan
Satish Peruvemba
Shylender Reddy
Rupa Sethu
Shams Siddiqi
Douglas Smith
Xun Wang

Administrative Support Staff:

Sherry Salvador
Alice Wilson

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The analysis presented in this report is designed to assist the staff of the Public Utility Commission of Texas in pursuing its integrated resource planning responsibilities. Two sophisticated resource planning models, the Load Management Strategy Testing Model (LMSTM) and PROSCREEN, were used to study the likely impact on system economics and reliability of reliance upon various combinations of potential supply-side and demand-side resources.

Working closely with the Commission staff, Center for Energy Studies researchers have developed suggested resource plans for six utility systems: TU Electric Company, Houston Lighting and Power Company (HL&P), Central Power and Light Company (CPL), Southwestern Electric Power Company (SWEPCO), West Texas Utilities Company (WTU), and the Lower Colorado River Authority (LCRA).

The analysis presented in this report suggests that greater reliance on demand-side management (DSM) and firm cogeneration may provide an opportunity to economically cancel or defer many of the generating unit additions currently planned by the state's utilities. Under the PUC Staff Base Case suggested resource plans, ten generating unit additions planned by these six utilities are either cancelled or deferred beyond 2006, the final year of this study's planning horizon. These cancelled or deferred units include HL&P's proposed Malakoff project, the Forest Grove and Pulverized Coal projects proposed by TU Electric, and the Coleto Creek Unit No. 2 and SWEPCO Lignite projects planned by the Central and Southwest operating companies. An additional sixteen proposed generating unit additions are delayed by at least one year (relative to the utilities' proposed on-line dates) under the PUC Staff Base Case assumptions.

Specific recommended DSM programs and cogeneration suppliers are not identified in this analysis. Instead, existing and anticipated market conditions and successful DSM programs are reviewed, and reasonable assumptions are developed regarding the potential contribution and economics of these resources. It is anticipated that the solicitation process and more comprehensive screening exercises will be used to identify the most beneficial alternative resources.

CHAPTER 1

INTRODUCTION

1.1 Background

This report was prepared by The University of Texas Center for Energy Studies (CES) to assist the staff of the Public Utility Commission of Texas (PUCT) in preparing its biennial forecast of load and capacity resources. Working closely with the Commission staff, CES has developed integrated resource plans for six of the state's larger electric utilities and analyzed a variety of alternative resource planning scenarios. The resource plans and scenarios presented here—based upon the Commission staff's demand and fuels price forecasts—are contrasted with current utility resource plans. Opportunities for cost-effective demand-side management (DSM) are identified. A variety of other relevant planning issues are analyzed.

Resource planning analysis is presented in this report for six electric utilities:

* TU Electric Company;
* Houston Lighting and Power Company (HL&P);
* Central Power and Light Company (CPL);
* West Texas Utilities Company (WTU);
* Southwestern Electric Power Company (SWEPCO); and
* Lower Colorado River Authority (LCRA).

Together, these utilities accounted for 63 percent of the state's peak demand and 73 percent of the state's installed generating capacity in 1990.

The analysis presented in this report suggests that many of the generating capacity additions presently planned by these six utilities may be economically deferred or cancelled by placing greater reliance upon cogeneration and DSM.

1.2 Complexities and Caveats

Recent changes in state and federal regulation and energy policy greatly complicate resource planning exercises such as this. Previously, a fairly well-defined set of possible utility and cogeneration resources would be evaluated, and the lowest-cost resources satisfying established reliability criteria would be selected. Then the utility and the Public Utility Commission (PUC) staff would develop least-cost integrated resource plans to meet anticipated demand growth in light of their planning assumptions. However, with changes to the federal Public Utility Holding Company Act designed to prompt greater competition in the generation sector, new power plant certification procedures at the PUC requiring solicitations for alternative supply and demand-side resources before permission to construct a new generating unit may be granted, and anticipated legislative and Commission initiatives designed to revamp the state's current resource planning process, new sources of power or demand reduction are likely to emerge. The proportion of supply-side and demand-side resources provided directly by the state's utilities may decline as non-utility generators, energy service companies, and customers compete with utilities to provide generation resources and energy efficiency. The scope of new potential resources will be limited only by the creativity exhibited by these new competitors.

In light of these regulatory changes and the new potential resources which are likely to emerge, it becomes difficult to develop resource plans through model simulations. The true least-cost plan is likely to become evident through competitive utility solicitations for supply-side and demand-side resources.

The suggested base case resource plans presented in this report—developed through the evaluation of a finite number of possible prospective resources and alternative planning scenarios—must be interpreted in light of these complexities. These suggested base case resource plans are designed to provide a reasonable forecast of the likely utilization of various resources, utility costs, electricity prices, and fuel use under the PUC staff's planning assumptions.

Some analysis regarding suggested on-line dates of capacity additions, the comparative costs of alternative resources, and other planning issues are presented in this report. However, some specific resource planning questions cannot be addressed in the absence of further study. The results of anticipated solicitations for resources will provide further insight into many planning issues. In addition, contractual and construction-related factors not considered in the modeling performed here may affect the feasible on-line date for a specific capacity addition. Resource alternatives to those considered here may emerge and prove competitive.

Given the planning assumptions employed here, the base case is our most likely expected outcome. However, new information and assumptions may result in a different outcome.

1.3 Approach

In the development of the integrated resource plans presented in this report, the following steps were successfully completed:

* Replication of each utility's resource plan in PROMOD and PROSCREEN software at CES.

* Representation of the base case resource plan developed by each utility in LMSTM software with each significant DSM program explicitly modeled for those utilities for which sufficient data were available.

* Analysis of each utility's present base case resource plan in light of the Commission staff's demand and fuels price forecasts and recommended adjustments to each utility's estimates of existing DSM program impact.

* Benefit-cost analysis of each utility's DSM programs, based upon the Commission staff's planning assumptions for those utilities which provided CES with sufficient data.

* The specification of hypothetical resource alternatives, including possible additional DSM programs, cogeneration contracts, and alternative power plant technologies.

* Analysis of the impact of hypothetical resource alternatives on system economics and reliability and a determination of whether changes in current utility plans might lower the cost of electricity without jeopardizing system reliability.

Development of the independent integrated resource plans presented in this report began with replication of each utility's current base case PROMOD and PROSCREEN solution on the RISC 6000 computer at CES. PROMOD and PROSCREEN are the production costing and resource planning models presently used by most of the state's major generating electric utilities. Input files to these models were received from each of the six utilities and successfully solved at CES.[1] In many cases, changes to the

---

[1] Replication and benchmarking are described in a companion report, *Electric Utility Resource Planning and Production Costing Projects: Final Report for FY 1991-1992*, CES, August 1992.

input files received from the utilities were required, due to differences in hardware and in the versions of the software used.

To provide a more detailed evaluation of the impacts and economics of each utility's DSM programs, the resource plans of each utility were modeled in the Load Management Strategy Testing Model (LMSTM). LMSTM, maintained by Electric Power Software, is an integrated resource planning model which simulates the impact of alternative resource plans on a utility's operation, financial status, rates, and demand. LMSTM was designed to estimate the impact of alternative resource strategies, particularly those involving DSM programs, over a study period of up to 45 years. Demand- and supply-side resources may be evaluated on a comparable basis.

Using computer programs developed at CES, each utility's PROMOD input file was converted into LMSTM input format. Because of differences between the algorithms employed by PROMOD and LMSTM, considerable calibration was required to ensure that each utility's operations and resource plan were accurately represented in LMSTM. The benchmarked results are presented in a companion report.[2]

While the utility-provided PROMOD and PROSCREEN input files did not explicitly represent DSM programs (with the exception of some interruptible load programs) demand-side resources were explicitly modeled for three utilities in LMSTM. Data pertaining to the costs of various existing or planned programs were obtained from Energy Efficiency Plan filings. Load shapes for some programs were obtained from the utilities modeled, while estimates of load impacts for programs for which no data were available were developed by CES. The Commission staff's recommended adjustments to the data provided by the utilities were incorporated.

A variety of hypothetical resource alternatives were specified and analyzed to assist in determining whether changes to current utility plans could result in lower costs. Working with the Commission staff, CES researchers specified hypothetical cogeneration contracts. Thirty-five alternative power plant technologies were screened

---

[2]*Electric Utility Resource Planning and Production Costing Projects: Final Report for FY 1991-1992*, CES, August 1992.

and six were ultimately analyzed[3]. A large number of possible DSM strategies were also screened, and six were ultimately used extensively in this analysis.

The data required to specify hypothetical DSM programs were collected from a variety of sources. Load shape information was collected from utilities inside and outside of Texas, demand-side resource proposals from an energy services company were reviewed, and simulations using the ESPRE building energy use simulation model were conducted.

The analysis described in this report is designed to greatly enhance the Commission staff's resource planning capability. A variety of alternative supply and demand-side resources have been screened using state-of-the-art resource planning models. Potential resources are integrated in the development of a recommended resource plan for six utilities.

As with any planning study, some limitations must be noted. The number of hypothetical resource alternatives considered was not exhaustive. Data constraints and resource constraints related to this project precluded consideration of a variety of promising supply- and demand-side resources. As discussed earlier, recent regulatory changes and anticipated greater competition in providing resources further complicate resource planning.

1.4 Key Assumptions

In any planning study, the general assumptions employed and the nature of the alternatives considered have a considerable impact on the results obtained. Some key assumptions are identified here.

All analysis reported here is premised upon the PUC staff's projections of electricity peak demand and sales, fuel prices, and impacts of current utility-sponsored DSM programs. In some cases, these projections were significantly different from projections adopted by the state's utilities.

[3]This analysis will be described in a forthcoming supplemental report.

Environmental externalities have not been considered here. The Texas Commission is presently considering whether to add monetized values, reflecting the social costs of pollution, to various prospective resources. This approach has been adopted in other states. Should Texas decide to pursue this approach, the results of this analysis may be affected.[4]

The number of resources considered was limited by time and resource constraints to those alternatives for which data were readily available. Despite recent improvement in their economic viability, additional renewable resources have not been considered. Neglect of these resources should not be interpreted as any conclusion regarding their potential value. Additional nuclear capacity has not been considered, due to limited utility and Commission interest in this potential resource. Purchased power transactions among utilities could not be easily studied through the modeling approach adopted here, which represented each utility system in isolation, aside from the Central and Southwest Corporation operating companies.[5] The hypothetical DSM programs screened were limited to those for which data were readily available.

Judgment ultimately plays some role in resource planning. While the optimal capacity expansion planning routine in PROSCREEN (PROVIEW) consistently selected natural gas-fired combined cycle units as the preferable utility-owned generating unit alternative, excessive reliance upon a single fuel source and technology for capacity additions raised concern among the project staff. Consequently, some results were qualitatively altered to acknowledge the value of fuel source and technology diversity. Prices at which utilities have recently secured firm cogeneration suggest its cost competitiveness relative to many utility-planned capacity additions. However, limits had to be judgmentally applied to dependence on this resource to reflect fuel diversity value, potential transmission system constraints, and other considerations.

---

[4]Related environmental issues are discussed in a separate report, Jay Zarnikau, Martha Baeza, and Rupa Sethu, *Pollution Emissions Taxes: Potential Impacts upon Electric Utilities in Texas: Summary of Preliminary Results*, CES, October 1992.

[5]Some analyses of the Central and Southwest Corporation operating companies were conducted using the multi-company version of PROSCREEN.

1.5 Organization of Report

A discussion of the data and methodology employed in this study is provided in the next chapter. The modeling approach and the procedures used to specify existing and prospective resources are described.

Chapters 3 through 8 present the resource planning analysis results obtained for each of the utility systems modeled. PUC staff base case results, employing assumptions recommended by the PUC staff, are described. An evaluation of current utility DSM efforts is included for those utilities which provided sufficient data. Results obtained from solving LMSTM with the alternative resources described in Chapter 2 follow. A recommended resource plan for each utility, utilizing the Commission staff's projections and planning assumptions, is reported.

The final chapter reports a summary of the results obtained through this integrated resource planning exercise.

CHAPTER 2

SUMMARY OF METHODOLOGY

This chapter describes the development of the scenarios that were analyzed to explore various planning issues. The results obtained from analyzing these scenarios are described in the chapters that follow.

2.1 Overview of Approach

A variety of alternative planning scenarios have been analyzed to assist the Commission staff in the development of suggested integrated resource plan for six of the state's major generating electric utilities. Two primary scenarios were analyzed for each utility:

- The utility case scenario, which sought to replicate each utility's current resource plan; and
- The PUC staff base case scenario, which reflects the PUC staff's load and fuels price forecasts and explicitly models the utility's current and planned DSM activities.[6]

For some utilities with near-term capacity needs, further scenarios were conducted to analyze the potential impacts of alternative generating unit additions, the substitution of cogeneration contracts for utility-owned capacity additions, and the economics and reliability of other supply-side or demand-side resources.

The following sections describe the development of these scenarios and the assumptions and data employed in their development.

2.2 Development of Utility Case Scenarios

To provide a starting point for the development of integrated resource plans, the current resource plans of each utility were modeled first. PROMOD and PROSCREEN

[6]Due to data limitations, TU Electric Company's and LCRA's energy efficiency programs could not be explicitly modeled. SWEPCO's DSM efforts were not modeled due to their trivial projected impacts.

input files were obtained from each utility, thereby insuring an accurate representation of each utility's system operation, projections, and planning assumptions. Programs were written at CES to convert PROMOD input files into LMSTM SUPPLY.IN input files. Utility demand projections were run through the SHAPE pre-processor to create LMSTM DEMAND.IN input files. The data necessary to create LMSTM FINAN.IN input files were collected from FERC FORM No. 1 filings, financial reports, PROSCREEN input files, responses to Requests for Information in rate cases, and other sources.

Once initial input files were created, the models were calibrated. Test runs of the models were conducted and changes were made to the input files until the results closely correlated to each utility's resource plan, cost projections, and simulation results. Remaining differences between the results obtained by CES using LMSTM and the simulations obtained by the utilities using PROMOD and PROSCREEN can be traced to differences in the algorithms employed in each model and other technical factors. However, the agreement obtained between the results from these alternative models may be considered more than sufficient for a long-term planning study of this nature.

Development of the utility case scenarios is described in much greater detail in a companion report: *Electric Utility Resource Planning and Production Cost Modeling Final Report*, CES, August 1992.

2.3 Developing the PUC Staff Base Case Scenario

The PUC staff, using its Econometric Electricity Demand Forecasting System and the Hourly Electric Load Model (HELM), has developed independent projections of future demand and energy for each major electric utility in Texas. Further, the Commission staff has developed recommended adjustments to this set of forecasts to account for the expected impacts of each utility's DSM activities and exogenous factors, such as the national appliance energy efficiency standards. These adjusted demand forecasts provide a basis for the PUC staff base case scenario.

In the PUC staff base case scenario for HL&P, CPL, and WTU, present and planned DSM programs have been modeled. Information pertaining to the cost and impact of significant DSM programs was obtained from each utility's December 1991 Energy Efficiency Plan. Program-specific load shapes were obtained from HL&P and

WTU. CPL's DSM programs were modeled using load shapes developed by the CES staff. SWEPCO's current DSM efforts were considered too insignificant to merit their inclusion in the modeling. Sufficient data from TU Electric Company and LCRA were unavailable.

In many instances the PUC staff recommended that the data provided by the utilities be adjusted to take into consideration "free ridership" or other biases. The PUC staff's adjustments to the utility-provided estimates are reflected in the modeling performed by CES.

The PUC staff's fuel price forecasts were also adopted in the development of the PUC staff base case. The Commission staff's projections for natural gas prices tend to be lower than those used by many of the state's utilities. In some cases, the fuel price projections provided to CES were the result of settlements among the parties in Avoided Cost cases at the Commission.

Resource alternatives were evaluated in light of the Commission staff's demand and fuel price projections and minimum planning reserve margin targets to develop a suggested PUC base case resource plan. The on-line dates of utility-planned capacity additions were altered, and the implications of such changes upon costs and reliability were discerned through such sensitivity analysis. Alternative levels of cogeneration reliance were analyzed. Hypothetical DSM options were screened, and those programs satisfying economic criteria (a total resource test benefit-cost ratio exceeding one) were included in the base case scenario.

2.4 Procedures Used to Model DSM Programs

LMSTM was used to analyze the DSM programs currently sponsored by HL&P, WTU, and CPL and to screen hypothetical DSM strategies for all six utilities. Using LMSTM's post-processor, DISPLAY, benefit-cost ratios were calculated from two perspectives: the utility cost test, and the total resource cost test.

Because LMSTM and DISPLAY cannot easily take into consideration the capacity value of DSM programs, an additional post-processor spreadsheet was developed by CES to add the capacity value of the DSM program being analyzed to the program's benefits as calculated by DISPLAY. The benefit-cost ratios were then recalculated with the program's capacity value included. A DSM program received capacity value only in those years when additional capacity was expected to have value, based upon projected reserve margins and the resource plan suggested for the utility.

The value of capacity was approximated using a levelized payment stream approach. This was calculated by CES based upon the utility's Avoided Cost filing with the Commission. Since the filings generally used relatively inexpensive combustion turbines, combined cycle units, or refurbishments to determine avoided capacity costs, the capacity values assigned to DSM programs in this analysis were fairly small. Because a peaking or intermediate load duty unit was used to calculate the value of additional capacity, the benefit-cost ratios associated with "baseload" conservation programs analyzed here may be slightly biased downward.

For the Central and Southwest Corporation operating companies, benefit-cost ratios were also calculated using a combined cycle natural gas-fired generating unit addition as the basis for determining the potential avoidable capacity costs associated with more aggressive reliance upon DSM. This approach was suggested by the Commission staff.

In many cases, existing DSM programs combine a number of end-uses and options. Since program participation and cost data are presented for the aggregate DSM program, data are insufficient to determine these program costs by end-use or option. Therefore, existing programs are modeled in aggregate. Although this method simplifies the use of participation, utility, and customer cost data, some accuracy may be sacrificed in determining program impacts on load shapes.

2.5 DSM Program Screening

A number of hypothetical DSM programs were specified to evaluate the impact of various DSM strategies on utility system loads and economics. These programs were considered as additions to each utility's current DSM offerings. The programs are Refrigerator Efficiency, Air Conditioning Direct Load Control, Water Heater Load Control, Swimming Pool Timers, Contract Lighting, and Commercial Lighting Efficiency.

These programs represent a variety of load shape objectives. The Air Conditioner Direct Load Control, Water Heater Load Control, and Swimming Pool Timer programs will result in load shifting and peak clipping. The Refrigerator Efficiency and Commercial Lighting Efficiency programs are designed to promote strategic conservation. Contract (Security) Lighting serves to fill valleys.

Identification of DSM opportunities was granted considerable attention in the project because of the very large potential for this resource in Texas and recent regulatory changes and proposals that have been advanced to promote the development of this resource. This section briefly reviews the potential for demand reduction and energy efficiency through DSM activity in Texas and details the assumptions employed in the DSM screening analysis conducted through this project.

2.5.1 Energy Efficiency as a Resource in Texas

In May 1992, CES released a preliminary assessment of opportunities to promote energy efficiency in Texas. This report concluded that if a comprehensive set of energy efficiency measures was implemented wherever technically feasible, all of the state's projected growth in residential and commercial sector energy consumption through the year 2010 could be eliminated. Energy usage for these customer classes can be reduced by at least 43 percent in the year 2010, relative to a reference case which assumes no changes in energy use for the building types considered. Peak electrical demand by the residential and commercial sectors can be reduced by 27 percent in the year 2010, relative to the frozen intensity reference case.

Some of the efficiency measures analyzed, however, were not considered economical in Texas. Thus, the potential savings associated with the measures were found to be somewhat lower than the technical potential savings. About 92 percent of the technical potential for electric energy savings can be captured at levelized costs below current prices, while about 77 percent could be implemented at levelized costs below marginal generation costs.

Because consumer behavior and market imperfections tend to limit the attainment of energy and peak savings that are technically feasible and cost-effective, achievable potential savings must also be considered. Other researchers have sought to determine the fraction of technical potential savings that can be considered achievable in other geographical regions. If it were assumed that their results are valid for Texas as well, then 30 percent of the state's potential savings can be achieved by aggressive utility DSM programs, facilitated by changes in regulatory policies and practice. An additional 30 percent of the technical potential savings can be achieved through more aggressive appliance standards, building codes, and other government actions. If all of the achievable savings were realized, more than half of the anticipated growth in residential and commercial sector electricity consumption could be satisfied through energy efficiency.

Among the residential energy efficiency measures studied, refrigerator efficiency measures were found to have the highest potential for reducing energy consumption in the May 1992 CES study (as noted in Table 2.1). According to the May 1992 CES study, replacing the existing stock of refrigerators with the most efficient models readily available in the marketplace (and of the same size and type as existing models) would conserve 9.43 billion kWh in 2010 relative to the amount that would be consumed in the absence of efficiency improvements in this appliance. Freezer efficiency measures can conserve an additional 6.16 billion kWh.

An additional 4.6 billion kWh can be conserved in 2010 by replacing the existing stock of residential air conditioners in Texas with high efficiency models and requiring that all air conditioners installed in new housing be high-efficiency models. As reported in Table 2.1, other promising efficiency measures in the residential sector include wrapping water heaters with insulation, sealing ducts, and setting back water heater thermostats.

In the commercial sector, the single measure found to have the greatest potential impact on electricity consumption was HVAC system improvements (see Table 2.2). Among HVAC efficiency measures, the greatest potential savings result from changes to heating and cooling systems to vary the supply air volume (with fan motor speed controls) to meet space heating and cooling loads at a fixed supply temperature. This modification will reduce fan energy consumption as well as heating and cooling coil loads because less simultaneous heating and cooling will occur. Implementation of this measure in all eligible commercial buildings will reduce energy consumption by 6.37 billion kWh in 2010.

Table 2.1
Efficiency Measures with the Greatest Potential Impact on Residential Sector Electricity Consumption

Refrigerator Efficiency Measures. This is a set of measures involving the replacement of existing refrigerators with the most efficient models available in the market.

Technical Potential Savings: 9.43 billion kWh

Automatic Setback Thermostats. Install automatic thermostats with 5 degree F nighttime heating setback and cooling set forward.

Technical Potential Savings: 6.84 billion kWh

Freezer Efficiency Measures. Replace existing freezers with the most efficient model available in market.

Technical Potential Savings: 6.16 billion kWh

High-Efficiency Air Conditioners. Select new systems or replace existing system with a high-efficiency unit. In multi-family dwellings, install heat pumps in addition to high-efficiency air conditioning systems.

Technical Potential Savings: 4.6 billion kWh

Cold Water Laundry. Wash half of all laundry loads in cold water.

Technical Potential Savings: 3.62 billion kWh

External Shading. Install solar screens on windows to reduce summer solar heat gain.

Technical Potential Savings: 3.98 billion kWh

Solar Water Heaters. Add a solar water heater system that would meet 60% of the hot water requirements.

Technical Potential Savings: 3.26 billion kWh

Interior Shades. Install interior light-colored shades to reduce solar gain.

Technical Potential Savings: 3.10 billion kWh

Low-Flow Showerheads. Install low-flow shower heads that use 2.5 gallons per minute.

Technical Potential Savings: 1.59 billion kWh

Water Heater Wrap Walls. Add an R-11 insulation wrap to the walls and top of an electric water heater.

Technical Potential Savings: 1.29 billion kWh

Water Heater Temperature Setback. Set back the thermostat of the water heater to 140 degrees F.

Technical Potential Savings: 1.26 billion kWh

Note: Each of the estimates of technical potential assumes that the measure was implemented to all eligible residences or commercial establishments. A description of each of these measures may be found in *Opportunities for Energy Efficiency in Texas* CES, May 1992.

Improving chiller designs to provide a higher efficiency in cooling equipment can result in additional savings of 5.98 billion kWh. The installation of an indirect evaporative cooling device in the outside air stream can reduce energy consumption by reducing outside air loads by cooling fresh air to near ambient wet bulb temperature and by removing a portion of light heat gain. Implementation of this measure can save roughly 4.29 billion kWh.

Table 2.2
Efficiency Measures with the Greatest Potential Impact on Commercial Sector Electricity Consumption

HVAC System Improvements. Convert from constant to variable supply air volume to meet space loads at a fixed cold deck temperature, reducing system capacity through reduction in air flow rates and improving the efficiency of fan motors.

Technical Potential Savings: 6.37 billion kWh

Higher COP Cooling Equipment. Improve the chiller design to provide for higher coefficient of performance (COP) of cooling equipment.

Technical Potential Savings: 5.98 billion kWh

Evaporative Cooling. Installation of an indirect evaporative cooling device in the outside air stream.

Technical Potential Savings: 4.29 billion kWh

Replace Fluorescent Lighting with reactive impedance replacements.

Technical Potential Savings: 4.17 billion kWh

Low Wattage Fluorescent. Replace existing standard fluorescent with low-wattage fluorescent.

Technical Potential Savings: 2.10 billion kWh

Window Films. Add a reflective film to the surface of all single-pane glass windows to reduce solar gain.

Technical Potential Savings: 3.44 billion kWh

Double-Glazed Windows. Use double-pane instead of single-pane windows.

Technical Potential Savings: 2.46 billion kWh

Systems Control Package. Introduce control options like economizer cycles to vary outside air fraction, night cycling, and outside air scheduling.

Technical Potential Savings: 2.36 billion kWh

Electronic Solid-State Ballasts. Replace present fluorescent lighting ballasts with electronic solid-state ballasts.

Technical Potential Savings: 2.12 billion kWh

See notes in Table 2.1

Of the lighting-related measures studied, delamping of existing standard fluorescent fixtures with reactive impedance replacements appears to provide the greatest conservation opportunities. A number of window and shading measures can result in considerable potential savings. The residential sector's contribution to the state's demand can be significantly reduced through shading measures and the installation of higher efficiency air conditioners.

Of the measures studied, more efficient cooling equipment holds the greatest promise for reducing the commercial sector's contribution to statewide peak demand. The installation of more efficient chillers can reduce 2010 peak demand by more than 3000 MW.

As shown in Table 2.3, the widespread installation of thermal energy storage devices can result in a decrease in the 2010 peak of more than 2000 MW. A number of utilities in Texas are now actively encouraging their customers to consider the implementation of such technologies.

2.5.2 Selection of Hypothetical DSM Programs for Screening

The budget and resource constraints associated with this project precluded the specification of an exhaustive set of feasible energy efficiency strategies. Consequently, the DSM options evaluated were limited to those for which cost and load shape impact data were readily available. Promising DSM strategies neglected from this analysis include motor efficiency programs and certain space cooling and heating measures, and a variety of appliance measures.

Because the set of DSM options explored was limited, recommendations are not provided regarding which DSM strategies or programs would be most appropriate for a particular utility. Solicitations for new capacity or more comprehensive screening exercises may be a better means of ascertaining such information. However, the screening conducted here indicates whether cost-effective opportunities do exist and provides some indication of DSM strategies worthy of further analysis.

The following hypothetical DSM programs are described further in this section:

- Refrigerator Efficiency
- Direct Load Control on Air Conditioners
- Load Control on Water Heaters
- Swimming Pool Timers
- Contract Lighting
- Commercial Lighting Efficiency

The results of the DSM program screening are reported in Chapters 3 through 8.

Table 2.3
Efficiency Measures with the Greatest Potential Impact on Commercial Sector Peak Demand

Higher COP Cooling Equipment. Improve the chiller design to provide for higher coefficient of performance (COP) of cooling equipment.

Technical Potential Savings: 3081 MW

Thermal Storage. An insulated cold water storage tank is cooled to 43 degrees F at night and on weekends, and cold water from the device is used during the afternoon to reduce the electric peak due to chiller operation.

Technical Potential Savings: 2065 MW

Evaporative Cooling. Installation of an indirect evaporative cooling device in the outside air stream.

Technical Potential Savings: 1446 MW

Window Films. Add a reflective film to the surface of all single-pane glass windows to reduce solar gain.

Technical Potential Savings: 925 MW

HVAC System Improvements. Convert from constant to variable supply air volume to meet space loads at a fixed cold deck temperature, reducing system capacity through reduction in air flow rates and improving the efficiency of fan motors.

Technical Potential Savings: 554MW

Double-Glazed Windows. Use double-pane glass windows.

Technical Potential Savings: 455 MW

Light-Colored Roof Treatment. Apply light-colored plastic paint to existing built-up roof layers to reduce solar heat gain through roofs.

Technical Potential Savings: 334 MW

Systems Control Package. Introduce control options like economizer cycles to vary outside air fraction, night cycling, and outside air scheduling.

Technical Potential Savings: 248 MW

Solar Shades (interior). Install light-colored blind on the inside of window openings to reflect some solar gain to the outside and slightly improve the thermal resistance of the overall window.

Technical Potential Savings: 194 MW

Roof Insulation. Add 3-inch fiberglass batts under the existing metal deck of present stock or add an additional 3 inches of preformed insulation over deck to new construction.

Technical Potential Savings: 190 MW

Wall Insulation. Use higher level of insulation to reduce heat conductance through walls.

Technical Potential Savings: 190 MW

2.5.3 Refrigerator Efficiency Programs

In the May 1992 study of opportunities for promoting energy efficiency in Texas, refrigeration was identified as the residential sector end-use where the greatest energy savings can be achieved. A hypothetical refrigerator efficiency program is described here. This program is modeled after Planergy's *Refrigerator Roundup* program, which has been implemented in other states.

Refrigerators have improved greatly in efficiency during recent years. A typical new refrigerator with automatic defrost and top-mounted freezer uses about 1000 kWh per year, while a typical 1973 model uses around 2000 kWh per year.

The program described here is designed to remove second refrigerators from residences. It is assumed that a "bounty" of $50 per refrigerator is offered for each unit. The incentive would be paid only for units that are operational and currently connected to the system. The refrigerators collected are disposed of in an environmentally safe manner.

Saturation of Second Refrigerators

Approximately 11 percent of all Texas households have a second refrigerator. This estimate was employed in the Public Utility Commission of Texas staff's End-Use Modeling Project. Thus, the number of eligible customers is equal to 11 percent of the state's total residential customers. It will be assumed that this saturation rate is constant across utility service areas.

Participation Rates

Of the eligible participants, 3.4 percent are expected to participate in the program each year, based upon the participation achieved in similar programs. This calculation results in the following estimates of annual participants:

Houston Lighting and Power Company	4370
TU Electric Company	7934
Central Power and Light Company	1797
Southwestern Electric Power Company (total system)	1127

West Texas Utilities Company	546
Lower Colorado River Authority	819

Free Rider Estimates

Estimates of free riderships are not available for this type of refrigerator efficiency program. However, a 10 percent free rider rate will be assumed here to ensure that the estimates of the effectiveness of this program are conservative.

Customer Costs

It is assumed there are no costs to the customer for participating in this program. All direct costs will be borne by the utility. Since this is a voluntary program, it may be inferred that participants expect to receive a net benefit from the program (otherwise, they would have no incentive to participate).

Utility Costs

Program implementation involves both a fixed cost and a non-recurring variable cost to the utility. Fixed costs were estimated by adjusting the data from a recent proposal submitted by Planergy to New York State Electric and Gas (NYSEG) in proportion to each Texas utility's number of residential customers. The following fixed program costs are assumed:

Houston Lighting & Power Company	$278,098
TU Electric Company	$504,808
Central Power and Light Company	$114,301
Southwestern Electric Power Company (total system)	$79,038
West Texas Utilities Company	$34,753
Lower Colorado River Authority	$52,130

A variable cost of $224 per participant was adopted from the Planergy proposal to NYSEG. This includes an incentive payment of $50 per participant and the costs associated with removing and disposing of old units. Both variable and fixed program costs were escalated at 4 percent per year.

Load Impacts

Planergy's estimates of load impacts are adopted here. Energy savings of 100 kWh per month per participant are assumed. This implies a demand reduction of 0.137 kW per hour for each participant. Differences in savings across day types or seasons are assumed to be negligible.

2.5.4. An Introduction to Load Control Programs

Utility control of residential and commercial loads has great potential for reduction of system peak demand. In Texas, direct control of residential loads is just starting to become significant, and the commercial sector is virtually untouched. Due to surplus capacity in recent years, most utilities have had little interest in demand reduction programs. However, most of the utilities that currently have large reserve margins will need additional capacity within the next decade unless demand reduction programs are implemented.

The residential sector contributes significantly to system peak demand. Air conditioning (AC) loads drive summer system peak demand and are the most commonly targeted. Water heaters are another good candidate for control, since they can be shut off for several hours at summer peak without discomfort to customers and are even more effective at reducing winter demand. Swimming pool pumps may be a good source of peak load reduction in those areas that have substantial numbers of swimming pools. Some winter-peaking utilities control space heater loads, but not enough data are available to determine whether this option might be viable in Texas.

Commercial AC and heating loads may also be candidates for direct control. However, commercial establishments in Texas have exhibited reluctance to allow utilities to control their cooling systems. For example, HL&P's commercial direct AC control program was canceled for lack of participation, and other utilities in the state have not even offered such a program. Dual-fuel heating systems may hold some potential where electric heat contributes significantly to peak demand.

A large amount of industrial load is controlled through interruptible rates. Otherwise, direct control of industrial loads is uncommon.

The only end-uses currently targeted for direct control by utilities in Texas are residential air conditioning and water heating. Most of the utilities examined in this study have not implemented direct control programs. However, it will be assumed that most utilities could implement air conditioning and water heater control programs in order to defer construction of additional peaking units.

HL&P started a pilot air conditioning direct load control program in 1991 with 200 customers. Thus, HL&P's existing program will be modeled according to their participation, load impact and cost data. TU Electric Company, CPL, SWEPCO and WTU have no such program. LCRA has had such a program in place for several years, so a hypothetical program is not modeled. None of these utilities has a water heater control program. Hypothetical programs will be designed for air conditioning, water heater, and swimming pool pump control at all utilities which do not have them but exhibit some potential. Hypothetical pilot projects will start in 1993.

2.5.5 Direct Control of Residential Air Conditioning

HL&P forecasts eventual control of 71,800 units. This is a very substantial program, but since the maximum program penetration is less than 10 percent of the potential market, it is possible that a greater commitment of resources could increase participation. Programs of this type rarely achieve high participation rates, however. For example, Florida Power and Light's aggressive direct load control program, which targets many different end uses, is predicted to achieve only 13.5 percent penetration of the residential market by the end of the decade. At that point, it is expected that the peak day load shape will impose a limit on the level of load management that is desirable.

Data on HL&P's costs, participation, and energy and demand impacts were obtained from HL&P's December 31, 1991 Energy Efficiency Plan (EEP). Implementation and marketing expenses are classified as fixed; equipment, incentive, and "other" expenses are assumed to vary directly with the number of customers in the program. Participant incentives consist of a $30 one-time payment and $20 per year, and the cost of installed switches is assumed to be $160. Expenses are projected to escalate at 4 percent annually to account for inflation. It is assumed that after 1996, no additional participants are added, and all efforts will be focused on retaining the current participant base. It is assumed that $500,000 per year will cover program administration.

A 1992 Florida Power and Light study indicated that less than 0.5 percent of all participants have dropped out of its program since 1987, and that the majority of movers can be replaced by the new tenants. Thus, dropouts and mobility losses are assumed negligible.

TU Electric Company's service area has a substantially larger number of central AC units than HL&P's (by about 40 percent), so it is assumed that TU Electric Company could implement a direct load control program 40 percent larger than HL&P's. Under this scenario, it is assumed that not only the number of participants, but also the program costs are 40 percent greater than HL&P's.

The other utilities considered here are much smaller than HL&P, so their hypothetical programs are modeled after a smaller program at Brazos Electric Cooperative. CPL's program is assumed to be exactly the same size and cost as Brazos', and will eventually include about 16 percent of the total current number of central AC units in its service area. SWEPCO and WTU's programs will be half the size of Brazos', amounting to a market penetration of about 20 percent; although the programs are smaller, fixed costs are not assumed to decrease. The program cost projections given by Brazos seem rather low compared to a similar program at LCRA, so they may be understated. Brazos' cost figures were used rather than LCRA's because they were more complete.

Since these utilities had not begun planning the implementation of such a program at the end of 1992, it is assumed that they could not possibly have a program running before 1994. Programs are assumed to be phased in between 1993 and 2001, and to be held constant at that point. It is assumed that the initial two years is a pilot program, in which no new units are installed for one year while an impact evaluation is performed to ensure that the transmitter and switches are working properly, and that the program is actually having an impact. Marketing, administration, and equipment costs are incurred in 1993 even though the program does not have participants involved until 1994. Air conditioning direct load control participation and fixed costs are illustrated in Table 2.4.

Table 2.4
Program Participation and Utility Fixed Expenses:
Direct Load Control of Residential Air Conditioning

PROGRAM PARTICIPATION:

YEAR:	TOTAL HL&P UNITS	TOTAL TU UNITS	TOTAL CPL UNITS	SWEPCO/WTU UNITS
1992	4,600	0	0	0
1993	22,200	0	0	0
1994	48,200	280	500	250
1995	63,700	280	500	250
1996	71,800	6,720	2,780	1,390
1997	remains	31,360	6,630	3,315
1998	constant	67,760	13,140	6,570
1999		89,460	19,640	9,820
2000		100,800	remains	remains
		remains	constant	constant
		constant		

FIXED EXPENSES:

YEAR:	HL&P	TU ELECTRIC	CPL	SWEPCO/WTU
1992	$1,019,100	0	0	0
1993	$2,496,000	$1,426,740	$164,550	$164,550
1994	4% escalation	$1,426,740	$82,200	$82,200
1995		$3,494,400	$75,780	$75,780
1996		4% escalation	4% escalation	4% escalation

HL&P has estimated that the coincident peak demand reduction from control of air conditioning loads is 1.36 kW per unit. This impact was accepted by PUC staff, but is unusually high compared to impacts experienced at other utilities. Thus, hypothetical programs at other utilities will assume only about half this impact, 0.7 kW per unit. A survey of utilities around the nation shows that this approximates the average impact of a typical cycling strategy (50-67 percent) on a typical cycling day.

System peak at most Texas utilities consistently occurs on a July or August weekday afternoon between 2 and 6 PM. Thus, air conditioner cycling normally occurs between 2 and 6 PM on selected weekdays during the months of June through September.

2.5.6 Water Heater Load Control

Direct control of water heaters is becoming more popular, because these loads may be shed for up to four hours in the summer without significant customer discomfort. Water heater loads are considerably smaller than AC loads at system peak, but the ability to shed these loads for several hours ensures that significant peak reduction will occur, without the necessity of matching cycling strategy to the unit's natural duty cycle, as in air conditioner cycling.

An examination of water heater control programs at several utilities revealed a wide range of estimated summer peak impacts, varying from 0.1 kW to 0.8 kW. According to PUC staff, a peak-coincident impact of 0.1 kW is most likely in Texas, so this impact is assumed in each control hour. Slight changes in demand reduction estimates significantly alter the apparent cost-effectiveness of the program.

Winter control of water heaters produces a larger load reduction than summer control, but there are several arguments against shedding water heater loads in the winter. For example, summer peaks at most of these utilities are much higher than winter peaks, and thus winter control does not affect system peak demand. Among major utilities in Texas, only LCRA has a significant winter peak, and they do plan to shed these loads at winter peak. Program participants are also less tolerant of a lack of hot water in the winter. Finally, bill credits are generally given in each month that loads are controlled; thus, controlling loads in winter as well as summer adds considerable expense to the program without any attendant effect on system peak load.

This program will target existing residential customers, rather than new homes. Giving builders a financial incentive to install an electric heater with a switch on it has the effect of encouraging installation of electric instead of gas-powered water heaters; thus, it promotes load building instead of conservation. Eventual penetration of the water heater control program is targeted at 20 percent to 30 percent of households with electric water heaters.

At the time these hypothetical programs were modeled, the only program of this type for which good cost data were available was Brazos Electric Cooperative's. Thus, all water heater programs were modeled after Brazos'; cost and participant numbers were based on a multiplier determined by the number of participants assumed to be targeted by each utility. Recent acquisition of data on LCRA's water heater load control program shows LCRA's expected costs of a very similar program are considerably higher than Brazos'. This indicates that using Brazos' cost figures may somewhat understate actual program costs. Thus, if a program is not cost-effective using these figures, it is extremely unlikely that the program is worthwhile.

HL&P's program is assumed to have approximately twice the participation and twice the cost of Brazos'; TU Electric Company's program is assumed to have four times the participation and cost of Brazos'; CPL is assumed to implement a program identical to Brazos'; while the SWEPCO and WTU programs will be only one-quarter the size and one-half the cost of Brazos', as illustrated in Table 2.5. Under these scenarios, penetration rates range from about 23 percent for WTU to about 33 percent for SWEPCO. Water heating direct load control participation and fixed costs are illustrated in Table 2.5.

2.5.7 Swimming Pool Pump Timers

Pool pumps are another end-use that can easily be controlled with a timer. The City of Austin discontinued its pool pump control program for lack of participation, but estimated that the peak demand reduction from each pump was about 1.2 kW. However, detailed load shapes obtained from Florida Power and Light showed most pool pumps operating in the morning, and thus exhibiting low peak coincidence. These shapes indicated load reductions of 0.58 kW between 2 and 3 AM, but only 0.2 kW between 5 and 6 PM. The Florida Power & Light load data are relied on in this analysis because they are the best currently available.

HL&P and TU Electric Company have much larger numbers of pool pumps than Austin, so the likelihood that successful programs could be implemented in these areas is high. HL&P estimates that there are about 94,000 pool pumps in its service area, and TU Electric Company estimates about 199,000. Estimated pool pump saturations at other utilities are either small or unavailable, so this program is modeled only for HL&P

Table 2.5
Program Participation and Fixed Expenses:
Direct Control of Water Heaters

PROGRAM PARTICIPATION:

YEAR	TOTAL EST. HL&P PARTICPANTS	TOTAL EST. TU ELECTRIC PARTICPANTS	TOTAL EST. CPL PARTICPANTS	TOTAL EST. WTU & SWEPCO PARTICPANTS
1993	0	0	0	0
1994	1,000	2,000	500	125
1995	1,000	2,000	500	125
1996	5,300	10,600	2,650	663
1997	12,200	24,400	6,100	1,525
1998	30,000	60,000	15,000	3,750
1999	49,800	99,600	24,900	6,225
2000	70,000	140,000	35,000	8,750
2001	97,000	194,000	48,500	12,125
2002	124,000	248,000	50,268	12,567
2003	remains constant	remains constant	remains constant	remains constant

FIXED EXPENSES:

YEAR	HL&P UTILITY FIXED COSTS	TU ELECTRIC UTILITY FIXED COSTS	CPL UTILITY FIXED COSTS	WTU & SWEPCO UTILITY FIXED COSTS
1993	$177,300	$354,600	$88,650	$44,325
1994	$164,400	$328,800	$82,200	$41,100
1995	$151,560	$303,120	$75,780	$37,890
1996	$151,560	$303,120	$75,780	$37,890
1997	$151,560	$303,120	$75,780	$37,890
1998	$151,560	$303,120	$75,780	$37,890
1999	$151,560	$303,120	$75,780	$37,890
2000	$151,560	$303,120	$75,780	$37,890
2001	$135,560	$271,120	$67,780	$33,890
2002	$125,560	$251,120	$62,780	$31,390
2003	4% escalator	4% escalator	4% escalator	4% escalator

and TU Electric Company's systems. Eventual program penetration of 30 percent may be possible.

Pool pumps will be controlled during the same 2 PM-6 PM peak period as other devices. Timers for pool pumps are assumed to be identical to the timers used to control water heaters. Their cost is estimated to be about $75 per switch, and installed cost is expected to be about $100 per switch (estimates from SWEPCO Energy Efficiency Plan). This cost is paid by the utility. The monthly incentive paid to participants in June through September will be $3 (this is Florida Power and Light's pool pump incentive). Hypothetical participation and cost assumptions are detailed below. Expense data for a program of this type were unavailable, so expenses were modeled after Brazos' water heater control program; these costs may be slightly high for this type of program. Cost figures do not include the cost of switches or incentive payments. Swimming pool pump timer participation and fixed costs are illustrated in Table 2.6.

2.5.8. Commercial Office Building Lighting Retrofit

Lighting represented approximately 14 percent of the U.S. demand and 25 percent of electrical energy consumption in 1990. As seen in Table 2.7, however, the commercial customer class is better suited to savings through DSM programs than either the residential or industrial customer classes. Commercial lighting has a far higher coincidence with class peak than the other sectors. This means that most of the savings will reduce system peak demand. The commercial sector has greater power consumption per customer for lighting than the other sectors, which will produce larger benefits with less marketing effort. Commercial enterprises will also require less utility incentive to pursue cost-effective retrofit programs than the residential sector, thereby reducing utility costs and facilitating program participation. The retrofit of existing commercial lighting systems can result in significant peak reduction and energy savings.

Program Synopsis

This hypothetical program analyzes two alternatives for retrofitting existing commercial building lighting fixtures. A typical commercial building with T-40 fluorescent bulbs is retrofitted with either (1) four standard T-8 bulbs including electronic ballasts or (2) two T-10 bulbs, electronic ballasts, and a parabolic reflector. Since retrofits are cost-effective, commercial enterprises should not require substantial rebates to induce participation. To increase participation in the program, it is best to insure that participants pay no out-of-pocket expenses.

Table 2.6
Program Participation and Fixed Expenses:
Swimming Pool Pump Timers

PROGRAM PARTICIPATION:

PROGRAM YEAR	HL&P ESTIMATED PARTICIPANTS	TU ESTIMATED PARTICIPANTS
1993	0	0
1994	250	500
1995	250	500
1996	1,325	2,650
1997	3,050	6,100
1998	7,500	15,000
1999	12,450	24,900
2000	17,500	35,000
2001	24,250	48,500
2002	29,850	59,700
2003	remains constant	remains constant

FIXED EXPENSES:

YEAR	HL&P PROGRAM COSTS	TU PROGRAM COSTS
1993	$44,325	$88,650
1994	$41,100	$82,200
1995	$37,890	$75,780
1996	4% escalator	4% escalator

It is also best for the utility to offer zero interest loans to the participant for the full amount of the retrofit cost. The loan can be repaid over five years[7] with 60 equal monthly installments added to the participant's electric bill. The payment will be less than the savings produced through the retrofit. Thus, the customer always reaps a savings with nearly all costs returned to the utility during the five-year payback period.

[7] A payback period must be chosen such that the monthly payment to the utility is approximately 90-95 percent of the retrofit savings, thereby minimizing the payback period while insuring that the customer never has out-of-pocket expenses as a result of participation in the program.

Table 2.7
Average U.S. Consumption of Electricity by Lighting End-Uses

	For the Overall System		For Customer Class	
	Percent of Peak	**Percent of Energy**	**Percent of Peak**	**Percent of Energy**
Residential	0.1	11.0	0.3	31.9
Commercial	11.1	9.7	27.8	31.5
Industrial	2.9	3.7	10.6	10.6

Source: EPRI Report, CU-6953, *Impact of Demand-Side Management on Future Customer Electricity Demand: An Update,* September 1990.

After the payback is complete the participant will reap 100 percent of the retrofit savings.

Utility Costs

The utility costs for the program will equal the market interest paid on the loaned money during the payback period. As a result, utility costs will exist for five years following the retrofit year with the annual interest costs decreasing through the five-year period. Table 2.8 illustrates the annual interest costs which would be borne by the utility for a typical participant in each of the retrofit programs. The capital invested is the cost to retrofit a prototypical building.

Engineering Analysis

Although this program is designed for application to commercial customers, the analysis is presented only for commercial office building space in the HL&P and TU Electric Company service areas. Therefore, these results represent only a fraction of the potential savings within the the commercial customer class. Although each type of commercial enterprise must be analyzed separately to obtain accurate impacts and costs, Table 2.9 offers a rough idea of the magnitude of potential savings in the commercial class if the office building results were extended to other building types.

Table 2.8
Utility Five-Year Interest Expenses per Program Participant

	T-8 Retrofit	T-10/Reflector Retrofit
Capital Invested	$38,836	$62,510
Annual Interest Rate	9.0%	9.0%
Interest Expense Year 1	2,702	3,968
Interest Expense Year 2	2,107	3,094
Interest Expense Year 3	1,512	2,220
Interest Expense Year 4	917	1,346
Interest Expense Year 5	322	473
Total Interest Expense	$7,560	$11,101

Table 2.9
Distribution of Commercial Building Types in Texas: 1990

Type of Facility	Total Floor Space (million sq ft)
Office Buildings	566
Retail	857
Education	402
Warehouse	520
Health Care	73
Food Sales	99
Assembly	631
Lodging	260
Others	416
Total	3,824

Source: *Opportunities for Energy Efficiency in Texas*, CES, May 1992.

Participation Rates

After seven years no additional retrofitting is assumed possible. Five scenarios (75, 50, 25, 10 and 1 percent) are analyzed where the percentage relates to the percentage of eligible participants that have been retrofitted by the end of the program. The impacts of the 10 percent scenario are analyzed.

Based on historical HL&P DSM penetration, the 10 percent scenario was chosen as most likely, and Tables 2.10 and 2.11 detail the individual and utility cost analyses for this case. Please note that eligibility factors of 40 and 80 percent of the total office building floor stock were used to reflect the high penetration of T-8 bulbs into the existing floor stock.

Free Rider Estimates

Free ridership is expected to be minimal since building management is not expected to consider a capital investment in retrofitting existing lighting systems primarily to produce energy savings. Furthermore, the utility will maintain program control through the process of soliciting participants and the retrofit contracting and funding process.

Customer Costs

This program is designed in such a way that the customer must always save and there are no out-of-pocket expenses for participants. Since the monthly retrofit savings exceed the monthly payback expense, compliance will be obtained. However, since this is not the case for the T-10/Reflector retrofit, the utility must either increase the payback period beyond five years or offer an annual incentive to cover these costs. For this analysis, the latter option was chosen.

In the engineering analysis in Table 2.10, maintenance costs were reduced in the upgraded lighting systems because of the use of fewer bulbs and ballasts. Even though customers save money in maintenance, these costs were not included in the customer savings. Inclusion of maintenance savings results in the need for out-of-pocket payments with reimbursement from the maintenance savings. The reduction of utility expenses was not considered essential to the success of the program. Customers will

Table 2.10
Analysis of Office Building Prototype T-8 and T-10/ Reflector Lighting Retrofit Programs

CATEGORY	Existing System	T-8 Retrofit	T-10/Refl Retrofit
BUILDING			
Utility	HL&P	HL&P	HL&P
Building Type	Office Bldg	Office Bldg	Office Bldg
Prototypical Bldg Area (sq.ft)	50000	50000	50000
Fixture Density (/1000 sq. ft.)	10.6	10.6	10.6
Total Fixtures	532	532	532
FIXTURE SPECS			
Power (W/fixture)	188.0	106.0	97.0
Annual Use (hr/yr)	3120.0	3120.0	3120.0
# Bulbs/Fix	4.0	4.0	2.0
# Ballasts/Fix	2.0	1.0	0.5
Bulb price ($)	2.0	4.5	9.0
Ballast price ($)	17.0	35.0	35.0
Bulb lifetime (hr)	6000	20000	20000
Ballast lifetime (hr)	70000	95000	95000
Project lifetime (yr)	25.0	25.0	25.0
Labor cost - installation ($/hr)	20.0	20.0	20.0
Labor cost - maint. ($/hr)	20.0	20.0	20.0
Diversity Factor	0.900	0.900	0.900
CONSUMPTION			
Annual Energy(MWH)	312.0	175.9	161.0
Peak Capacity (kW)	90.0	50.8	46.4
Energy Savings (MWH/P/yr)	0.0	136.1	151.0
Peak Savings (kW/P)	0.0	39.3	43.6
CUSTOMER COSTS			
Total Consumption($/yr)	0.0	-6944.0	-7648.1
Change in Energy Cost($/yr)	0.0	-4051.9	-4438.5
Change in Power Cost ($/yr)	0.0	-1601.9	-1777.7
Change in A/C Cost ($/yr)	0.0	-1290.3	-1431.9

Table 2.10 (Continued)
Analysis of Office Building Prototype T-8 and T-10/ Reflector Lighting Retrofit Programs

CATEGORY	Existing System	T-8 Retrofit	T-10/Refl Retrofit
Total Maintenance($/yr)	7182.1	3386.7	2440.3
Bulbs Replaced (#/yr)	1106.6	332.0	166.0
Bulb Cost ($/yr)	2213.1	1493.9	1493.9
Labor ($/yr)	3688.5	1106.6	553.3
Subtotal Bulbs ($/yr)	5901.7	2600.4	2047.1
Ballasts Replaced (#/yr)	47.4	17.5	8.7
Ballast Cost ($/yr)	806.2	611.5	305.8
Labor ($/yr)	474.2	174.7	87.4
Subtotal Ballasts ($/yr)	1280.4	786.2	393.1
Total Inventory ($/yr)	251.6	175.4	150.0
Lamps ($/yr)	184.4	124.5	124.5
Ballasts ($/yr)	67.2	51.0	25.5
Total Capital ($)	0.0	33516.0	49210.0
Bulbs ($)	0.0	9576.0	9576.0
Ballasts ($)	0.0	18620.0	9310.0
Reflector ($)	0.0	0.0	19684.0
Labor ($)	0.0	5320.0	10640.0
Annual payment ($/yr)	0.0	6703.2	9842.0
UTILITY COSTS			
Finance ($)	0.0	33516.0	49210.0
% Less Than Market	0.0	9.0	9.0
Avg. Finance Exp.($/yr)	0.0	1512.4	4620.5
Incentive($/yr)	0.0	0.0	2500.0
Total Utility Costs ($/yr)	0	1512.4	7120.5
AVG CUST SAVINGS-payback per. ($/yr)	0.0	240.8	306.1
CUST SAVINGS post-payback ($/yr)	0.0	6944.0	7648.1
AVG CUST SAVINGS INCL MAINT - payback period ($/yr)	0.0	4036.3	2547.9
CUST SAVINGS INCL MAINT - post payback period ($/yr)	0.0	10739.5	12389.9

Table 2.11
10% Scenario Analysis for HL&P

	Existing System	T-8 Retrofit	T-10/Refl Retrofit
Customer Costs ($/sq ft/yr)			
Unit Cust Savings: 1-5 yr ($/sq ft/yr)	0.0000	0.0048	0.0061
Unit Cust Savings: 5+ yr ($/sq ft/yr)	0.0000	0.1389	0.1530
Customer Savings incl Maint. ($/sq ft/yr)			
Unit Cust Savings: 1-5 yr ($/sq ft/yr)	0.0000	0.0807	0.0510
Unit Cust Savings: 5+ yr ($/sq ft/yr)	0.0000	0.2148	0.2478
Avg. Utility Costs: 1-5 yr ($/yr)		822,125	4,410,242
Avg. Variable Costs ($/sq ft/yr)	N.A.	0.0302	0.0924
HLP Office Footage (million sq ft)	N.A.	232.13	232.13
Eligibility Factor	N.A.	0.4	0.8
Eligible Office Footage (million sq ft)	N.A.	92.9	185.7
Anticipated Penetration Rate	N.A.	0.250	0.250
Total Footage Participating (million sq ft)	N.A.	23.21	46.43
Total Avg. Variable Costs ($/yr)	N.A.	702,125	4,290,242
Total Fixed Costs ($/yr)	N.A.	120,000	120,000
Actual Unit Capacity Saved (kW/sq ft)	0	0.000785	0.000871
Actual Capacity Savings (MW)	0	18.2	40.5
Actual Energy Savings (MWH/yr)	0	56,870	126,224
Avg. Capacity Costs ($/kW/yr)	0	45.10	109.01

reap an additional savings of $3,800 for the T-8 retrofit or $4,750 for the T-10/Reflector retrofit.

In the office building retrofit scenario, the payback period was found to be five years with monthly installments of $559 and $820, respectively. However, savings resulting from the retrofits are $579 and $637, respectively. The deficit in the T-10/ Reflector program requires an incentive of $183 monthly or about $2,196 annually to provide for a financial margin. All financial transactions occur on the customer's monthly electric bill.

Customer savings for the two programs were determined to be 0.5 and 0.4 ¢/sq ft/yr during the payback period, while participants would reap 21.5 and 24.8 ¢/sq ft/yr after payback. Over the 25-year project lifetime, the T-8 and T-10/Reflector programs result in a savings of approximately $140,000 and $155,000 respectively per participant. The 10 percent scenario yields $25,915,756 in total customer savings and $50,209,735 in energy savings.

Utility Costs

Fixed costs are estimated at $120,000. These costs are expected to support three to four employees to administer the program. The number of administrative employees is assumed independent of the program. Variable costs from interest payments on the loans to participants and incentive payments in the case of the T-10/Reflector retrofit are modeled; the interest rate was chosen at 9.0 percent annually. Since most of the utility costs are variable and arise from interest, the capacity costs presented in Table 2.12 are a function of interest rates which the utilities can obtain.

To implement the retrofits, capital financing of $33,516 and $49,210 respectively is required. With a payback period of five years for both programs, interest charges were calculated at an annual interest rate of 9.0 percent. An incentive payment of $2,400/year is required for participants in the T-10/Reflector retrofit during the loan repayment period. After repayment of the loan there is no further cost for the customer. Unit variable costs were determined to be 3.2¢ and 14.3¢ per square foot per year during the payback period while average annual utility cost per participant amount to $7,561 and $23,103, respectively.

Load Impacts

The office building lighting loads are assumed to be 90 percent coincident. This program is an effective target to reduce demand. The T-8 retrofit results in a 39.3 kW peak reduction and an annual energy savings of 136.1 MWH per participant, while the T-10/Reflector retrofit savings equal 43.6 kW and 151 MWH annually. Unit peak impacts were determined to be 0.786 and 0.872 kW/sq. ft. of retrofitted area. Combining the load reduction and utility cost results yields for the 10 percent scenario respective capacity costs of $274.55 and $566.70 per kW as seen in Table 2.13.

Table 2.12
Capacity Costs for the 10% Scenario

	T-8 RETROFIT				T-10/REFLECTOR RETROFIT			
YR.	PROGRAM COST	PARTIC-IPANTS	IMPACT (kW)	COST ($/kW)	PROGRAM COST	PARTIC-IPANTS	IMPACT (kW)	COST ($/kW)
1	27,024	10	393.0	68.71	159,195	25	1,090	146.05
2	61,610	15	589.5	104.51	455475	50	2,180	208.93
3	114,294	25	982.5	116.33	708,612	50	2,180	325.05
4	152,103	25	982.5	154.81	917,796	50	2,180	421.07
5	202,060	35	1375.5	146.90	1,083,299	50	2,180	496.93
6	247,431	40	1572.0	157.40	1,155,129	50	2,180	529.88
7	262,802	35	1375.5	191.06	1,155,129	50	2,180	529.88
8	174,416	0	0	N.A.	836,739	0	0	N.A.
9	100,906	0	0	N.A.	562,031	0	0	N.A.
10	44,999	0	0	N.A.	331,005	0	0	N.A.
11	11,281	0	0	N.A.	143,661	0	0	N.A.
12	0	0	0	N.A.	0	0	0	N.A.
TOT.	1,398,926	185	7270.5	192.41	7,508,340	325	14,170	529.88

Since penetration rates depend on how aggressively utilities pursue DSM activities, Table 2.13 is presented to summarize the energy savings, peak reduction, and capacity costs for the five scenarios analyzed. Note that energy savings are given for the 25-year life of the project.

The 10 percent Scenario T-8 and T-10 Commercial Lighting Retrofit programs are also analyzed in LMSTM for TU Electric Company and HL&P. The energy and peak demand impacts are consistent with those listed for the 10 percent scenario in Table 2.13. The benefit-cost ratios and the energy and peak demand impacts are listed in Chapter 3 for TU Electric Company and Chapter 4 for HL&P.

Table 2.13
Penetration Rate Effects for Office Building Lighting Retrofits

	SCENARIO	T-8 RETROFIT	T-10 / REFL RETROFIT
Energy Saved (MWH/yr)	75	170,610	378,672
	50	113,740	252,448
	25	56,870	126,224
	10	22,748	50,490
	1	2,275	5,049
Peak Savings (MW)	75	54.7	121.4
	50	36.5	80.9
	25	18.2	40.5
	10	7.3	16.2
	1	0.7	1.6
Capacity Costs ($/kW/yr)	75	203.51	535.04
	50	208.80	537.73
	25	225.86	544.47
	10	274.55	566.70
	1	1057.75	911.28

2.5.9 Contract Lighting

One issue of interest to system planners and regulators is the impact of "valley filling" demand side management strategies on utility system economics. Many utilities in Texas are presently pursuing valley filling programs to increase their off-peak sales and to generate additional revenues.

To explore the impact of valley filling strategies on utility system economics, a scenario was analyzed which assumed implementation of a DSM program similar to HL&P's contract lighting program. HL&P's contract lighting program primarily satisfies the needs of customers for security and area lighting. The tariff-based service utilizes high-efficiency, high-pressure sodium and mercury vapor lighting fixtures which are installed, maintained, owned, and operated by the utility. The customer is charged a fixed monthly rate, depending on the size and type of light selected for a minimum of two years. This program is designed to enhance the safety and security of the utility's customers through increased utilization of energy-efficient outdoor lighting. The objective of the program is to improve system load factor through valley filling.

The load shapes for this scenario were assumed to follow the same shape as the contract lighting program implemented by HL&P. Since this is a valley filling program, the impact of this DSM strategy on the load shape is seen only in the off peak hours. The peaks for both the summer and winter months remain unchanged. The program has a positive impact on the valley of the load shape. The expected impact on the summer load shape for one utility, WTU, is show in Table 2.14. The impact on winter load shapes may be expected to follow a similar pattern.

All data for this scenario are based on HL&P's existing program. It was assumed that the total cost incurred by other utilities was proportional to HL&P's program costs. The number of participants was scaled in relation to each utility's size.

2.6 Firm Cogeneration Capacity

Cogeneration refers to the sequential production of steam (or thermal or shaft energy) and electricity in the industrial process. In Texas, many petrochemical, chemical, and petroleum refining facilities have installed turbines in their processes and are producing electricity. More than 10 percent of the power sold by utilities in Texas is produced by cogenerators.

"Firm capacity" contracts enable the purchasing or host utility to place a high degree of reliance upon the availability of power from the cogenerator. The cogenerator incurs an obligation to provide the power and must meet certain reliability standards. Contractual penalties can be imposed for non-delivery. A capacity payment is typically made by the utility in addition to an energy payment.

For the purpose of the FORECAST '92 project, only firm capacity has been studied as a resource alternative. Using LMSTM and PROSCREEN, firm cogeneration was assessed as a capacity resource planning option. Its cost and reliability are compared to other potential supply- and demand-side options.

While the host utility has an obligation to purchase all cogenerated energy offered by qualifying facilities under federal and state law, utilities in Texas are under no obligation to contract for firm capacity in excess of their capacity needs. Utilities negotiate to purchase firm capacity from cogenerators through the state's "competitive negotiation" system. Under this system, utilities and cogenerators negotiate the price at

Table 2.14
WTU: Contract Lighting Program

Summer Hourly Load Shape

	1992		1996		2001		2006	
Hour	Reference (MW)	Impact (MW)	Reference (MW)	Impact (MW)	Reference (MW)	Impact (MW)	Reference (MW)	Impact (MW)
1	775.8	0.33	850.0	1.63	947.8	3.27	1043.0	4.9
2	735.3	0.33	804.3	1.63	894.2	3.27	983.7	4.9
3	710.0	0.33	776.3	1.63	861.7	3.27	948.2	4.9
4	697.2	0.33	761.8	1.63	844.7	3.27	929.4	4.9
5	686.0	0.33	749.2	1.63	830.0	3.27	913.1	4.9
6	692.8	0.23	756.9	1.14	838.9	2.29	922.9	3.43
7	725.0	0	791.6	0	877.7	0	963.8	0
8	772.2	0	843.8	0	937.9	0	1029.3	0
9	841.4	0	921.6	0	1029.0	0	1130.1	0
10	903.7	0	991.8	0	1111.4	0	1221.4	0
11	961.9	0	1058.2	0	1190.2	0	1309.6	0
12	1009.3	0	1110.8	0	1251.1	0	1376.1	0
13	1031.3	0	1135.7	0	1280.4	0	1408.5	0
14	1064.7	0	1173.9	0	1325.8	0	1459.5	0
15	1091.4	0	1205.3	0	1364.2	0	1503.5	0
16	1112.6	0	1230.0	0	1394.1	0	1537.4	0
17	1118.2	0	1238.2	0	1405.7	0	1552.2	0
18	1107.7	0	1224.6	0	1387.7	0	1530.2	0
19	1094.1	0	1207.2	0	1365.1	0	1503.0	0
20	1071.8	0.17	1182.0	0.87	1335.5	1.73	1470.3	2.6
21	1037.5	0.33	1143.3	1.63	1290.0	3.27	1420.1	4.9
22	1022.4	0.33	1126.7	1.63	1271.0	3.27	1399.5	4.9
23	946.9	0.33	1042.1	1.63	1172.3	3.27	1290.8	4.9
24	819.8	0.33	899.6	1.63	1006.0	3.27	1107.6	4.9

which capacity will be made available and the contractual terms and conditions. The prices paid for cogeneration must not exceed the utility's "avoided cost." Utilities must abide by the Commission's wheeling rules and other policies.

Texas has an abundance of cogeneration. As of 1991, 7,360 MW of capacity were in operation, 557 MW were under construction, and 376 MW were proposed. (See *Cogeneration and Small Power Production in Texas: 1991 Annual Report,* Public Utility Commission of Texas, June 1992.)

Of the megawatts in operation, 3,287 MW were under contract to provide firm capacity. Four utilities in Texas contracted with cogenerators for capacity in 1989:

Houston Lighting and Power	956 MW
TU Electric Company	1,992 MW
Texas-New Mexico Power	300 MW
Southwestern Public Service	39 MW

Some portion of the 4,073 MW of capacity that was not under contract to provide firm capacity to utilities must be considered unavailable. Some of this capacity is exclusively designed to serve the electrical needs of the facility's owner. Some portion of the remaining capacity may be too unreliable to serve a utility's needs. It would be reasonable to assume, however, that at least 2,000 MW of the capacity not under contract to provide firm capacity to utilities in 1991 would have been offered at a competitive price had the utilities experienced a greater need for capacity.

The recent Load and Capacity Resource Forecast filings by HL&P and TU Electric Company indicate that these utilities have not committed to renewing their present contracts with cogenerators for firm capacity. Thus, there is a likelihood that some capacity currently under contract may be freed up in the future. This could include capacity from the following suppliers:

- Occidental (La Porte) 225 MW contract with HL&P expires in 1993
- Dow (Freeport) 325 MW contract with HL&P expires in 1994

In summary, we can assume that a very large, and possibly increasing portion of the utility industry's future capacity needs might be met by cogeneration.

The three main costs incurred in purchasing firm cogenerated power are capacity charges, energy charges, and wheeling charges. However, it is assumed here that wheeling charges are included in energy and capacity charges.

In developing a reasonable estimate of the price at which firm cogeneration may be secured, recent contracts and offers for capacity were reviewed. In Texas, capacity payments are determined in negotiations between utilities and cogenerators. While some of the contracts negotiated in the early 1980's had 1991 capacity payments as high as $286,462 per MW (e.g., the contract between Occidental and HL&P), payments for contracts recently negotiated had 1991 payments as low as $60,000 per MW (e.g., the AES Deepwater contract with HL&P and the Clear Lake Cogeneration contract with Texas-New Mexico Power Company).

Under the Commission's rules, payments by utilities to cogenerators may not exceed the utility's avoided cost. The most recent avoided cost calculations were filed by the utilities in December 1991.

It should be noted that avoided cost payment streams calculated by many of the utilities are lower (after adjusting for expected inflation through the avoidable unit's start date) than the current market price of cogeneration, of about $60,000 per MW per year. However, many of these filings have neither been reviewed nor approved by the Commission and are not utilized in this analysis. In this analysis, the market price for cogeneration capacity of $60,000 per MW was assumed for the year 1993. This was then escalated at a 4.5 percent rate.

The energy payment is designed to compensate the cogenerator for the cost of fuel and other variable costs. This payment is most often based upon the generation cost of an "avoided unit." This payment may differ significantly by utility, based on individual avoidable units. Natural gas price projections and combined cycle natural gas-fired generating unit heat rates were adopted as the basis for developing an energy payment stream.

CHAPTER 3

TU ELECTRIC COMPANY

3.1 Introduction

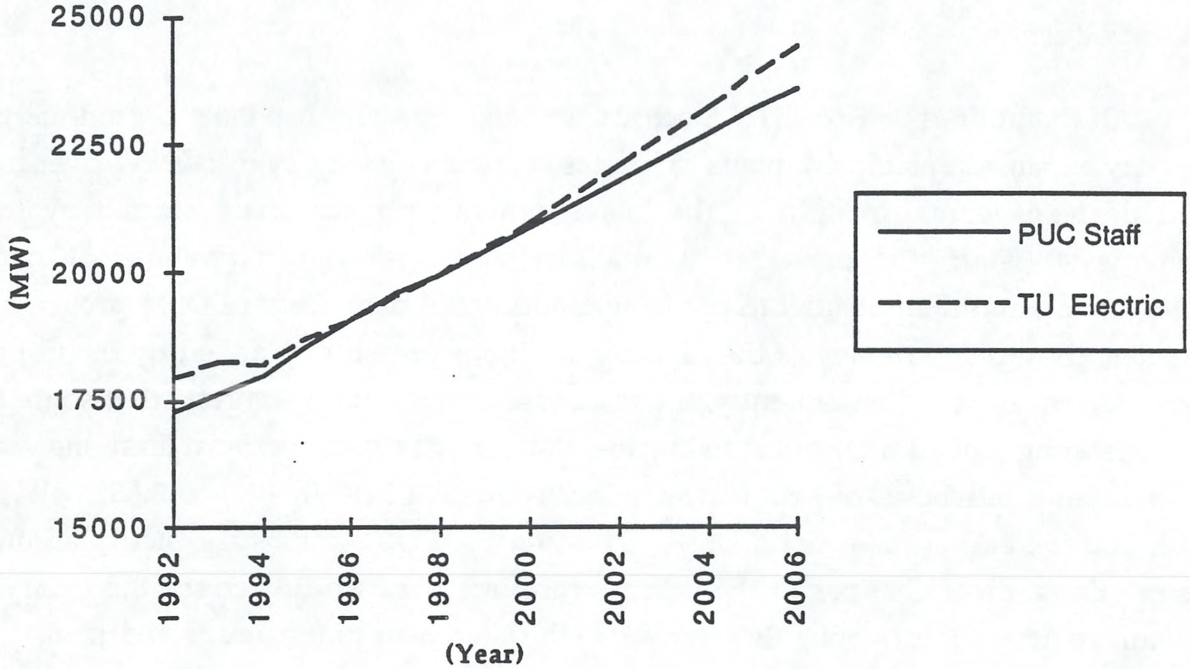
Of the utilities in Texas, TU Electric Company presently has the most ambitious capacity expansion plan, with plans to increase system capacity by 6,854 MW over the next thirteen years. In light of the lower demand projection developed by the Commission staff, the projected availability and cost-competitiveness of firm cogeneration and the potential to implement additional cost-effective DSM programs, opportunities to defer many of the capacity additions presently planned by the utility are expected to rise. Consequently, the PUC base case scenario suggests that some of the generating unit additions planned by the utility may be deferred by at least one year by increasing purchases of firm cogeneration from 1,771 MW in 1993 to 2,652 MW in 2006, and increasing reliance on DSM. Based on the PUC staff's suggested planning assumptions, these changes to the utility's resource plan would reduce the utility's revenue requirements by roughly 4 percent in the later years of the forecast horizon.

3.2 PUC Staff Base Case Scenario

The PUC base case scenario is premised on the independent demand and fuel price projections developed by the Commission staff. In light of these projections, the utility's resource plan was adjusted accordingly, in an effort to maintain reliability while minimizing projected revenue requirements and rates. As indicated in Figure 3.1, the PUC staff's projection of peak demand is significantly lower than the utility's after 1998, thus implying opportunities to defer planned capacity additions without sacrificing reliability.

The PUC base case scenario was developed using the PROSCREEN integrated resource planning model and planning assumptions developed by the PUC staff. The PROVIEW submodel of PROSCREEN was used to derive an optimal expansion plan for TU Electric and the integration of generation decisions, financial, and rate impacts in a single framework. The PUC base case expansion plan meets the Commission staff's recommended minimum reserve margin of 18 percent for TU Electric and takes into

Figure 3.1
Comparisons of PUC Staff and Utility Adjusted Peak Demand Projections:
TU Electric Company



account the Commission staff's suggested delay in the on-line dates of Twin Oak Units 1 and 2 because of environmental considerations.

Given the current and projected market conditions and the assumptions discussed in Chapter 2, firm cogeneration can often provide a cost-effective alternative to the construction and operation of new power plants. The PUC base case scenario assumes that the utility will increase purchases of firm cogeneration from 1,771 MW in 1993 to 2,652 MW in 2006. The utility's present resource plan calls for 2,244 MW of cogeneration purchases in 1998, but declining reliance on this resource in later years as existing contracts expire. These two projections of firm cogeneration purchases are compared in Table 3.1

The on-line dates for capacity under the PUC base case scenario are compared to the utility's planned on-line dates in Table 3.2. Under the PUC staff base case, the lignite-fired Twin Oak Units 1 and 2 were deferred by four and five years, respectively.

Table 3.1
TU Electric Company
Purchases of Firm Cogeneration under Utility and PUC Staff Base Case Resource Plans (MW)

Year	Utility Projection	Total Purchases under PUC Staff Base Case
1992	1,771	1,771
1993	1,771	1,771
1994	1,421	1,771
1995	1,321	1,421
1996	1,444	1,454
1997	1,994	1,994
1998	2,244	2,244
1999	2,034	2,084
2000	1,960	2,010
2001	1,955	2,224
2002	1,955	2,455
2003	N/A	2,321
2004	N/A	2,595
2005	N/A	2,599
2006	N/A	2,652

Two 136 MW combustion turbines were deferred by one year. Two 145 MW and two 136 MW combustion turbines are built a year earlier, while two 136 MW combustion turbines and two 645 MW combined cycle units are built two years earlier. Two coal-fired units planned by the utility (Pulverized Coal Unit 1 and Forest Grove Unit 1) and one 620 combustion turbine were deferred beyond the forecast horizon while two 620 MW combined cycle units came on line earlier than planned by the utility. The projected system reserve margin remains above, but close to, the target reserve margin of 18 percent in each year of the planning period under the PUC base case. Under the utility expansion plan, the reserve margin is 3-4 percent higher for the years 2000 through 2006, as shown in Table 3.3.

Results from the PUC staff base case scenario are presented in Tables 3.4 through 3.8 and Figures 3.2 and 3.3. The "utility case" results presented in these tables and figures were developed using the energy, demand, fuel price, and cogeneration projections

Table 3.2
TU Electric Company: Changes in On-Line Dates for Capacity Additions under PUC Staff Base Case Scenario

Utility Planned Commercial Operation Date	On-Line Date Under PUC Staff Base Case Scenario	Plant Name	Unit No.	Regulatory Status	Net MW Owned	Primary Fuel	$/kW Including AFUDC
1993	1993	Comanche Peak	2	CCN	1,150	URAN	3,626
1999	2003	Twin Oak	1	CCN	750	LIG	2,119
2000	2005	Twin Oak	2	CCN	750	LIG	1,235
2001	1999	Undesignated CC (CCCT1)	1	NOI	645	NG	774
2002	2000	Undesignated CC (CCCT2 1)	1	NOI	645	NG	656
1998	1997	Undesignated CT (COMBS001)(COMBUS98)	2	NOI	145	NG	-
1998	1997	Undesignated CT (COMBS002)(COMBUS98)	1	NOI	145	NG	-
2005	2002	Undesignated CC (CCCT 3 1)	1	NOI	620		
2003	>2006	Forest Grove	1	CCN	660	LIG/SUB	2,413
2004	>2006	Pulverized Coal Unit	1	NOI	650	LIG/SUB	1,693
2006	2004	Undesignated CC (CCCT4 1)	1	-	620	NG	-
2003	2001	Undesignated CT (COMBS014)(COMBUS03)	1	-	136	NG	-
2003	2001	Undesignated CT (COMBS021)	2	-	136	NG	-
2004	2003	Undesignated CT (COMBS022)	1	-	136	NG	-
2004	2003	Undesignated CT (COMBS023)	2	-	136	NG	-
2004	2005	Undesignated CT (COMBS024)	1	-	136	NG	-
2005	2005	Undesignated CT (COMBS025)	2	-	136	NG	-
2005	2006	Undesignated CT (COMBS026)	1	-	136	NG	-
2006	2006	Undesignated CT (COMBS027)	2	-	136	NG	-
2006	>2006	Undesignated CT (COMBS028)	1	-	136	NG	-
2006	2006	Undesignated CC (CCCT 51)	1	-	620	NG	-

(NOTE: The utility-planned commercial operation date and on-line date under PUC staff base case scenario refer to the year in which peak demand will first be served by the unit.)

KEY: NG=Natural Gas URAN=Uranium LIG=Lignite SUB=Subbitumous
CCN=Certificate of Convenience and Necessity NOI=Notice of Intent

Table 3.3
TU Electric Company: Comparisons of New Capacity Additions and Reserve Margins of PUC Base Case and Utility Case

	Utility Case		PUC Base Case	
Year	Capacity Addition	Reserve Margin (%)	Capacity Addition	Reserve Margin (%)
1993	1,150	29.5	1,150	29.5
1994	0	25.0	0	25.0
1995	0	20.8	0	20.8
1996	0	18.0	0	18.0
1997	0	17.9	290	19.3
1998	290	18.2	0	18.2
1999	750	18.5	645	18.0
2000	750	19.1	645	18.1
2001	645	20.7	272	18.0
2002	645	22.1	620	19.3
2003	932	21.0	1,022	18.7
2004	1,058	22.5	620	18.3
2005	892	21.7	1,022	18.1
2006	892	21.5	892	18.0

Table 3.4
TU Electric Company
Total Fuel Costs - Comparison of Utility Case with PUC Base Case
(Thousands of Dollars)

Year	Utility Case	PUC Staff Base Case
1993	1,234,580	1,234,580
1994	1,281,552	1,281,552
1995	1,458,465	1,458,465
1996	1,506,004	1,506,004
1997	1,524,439	1,525,512
1998	1,650,750	1,650,750
1999	1,728,206	1,795,092
2000	1,829,731	1,968,872
2001	2,002,106	2,187,477
2002	2,081,067	2,259,068
2003	2,260,951	2,411,599
2004	2,413,451	2,609,369
2005	2,571,310	2,694,040
2006	2,788,269	2,917,466

adopted by the Commission staff, but retain the capacity expansion plan. The utility case scenario was developed at the request of the Commission staff.

The PUC base case, in general, results in higher fuel costs but lower revenue requirements than the utility case over the planning period, as shown in Tables 3.4 and 3.6. The average rates for both scenarios are presented in Tables 3.7 and 3.8. For the years 1998 to 2006, the average rate is lower under the PUC base case scenario than under the utility case.

Table 3.5
TU Electric Company
Projected Fuel Consumption under PUC Staff Base Case Assumptions
(Thousands of MMBtu)

Year	Natural Gas	Coal	Lignite	Nuclear
1993	253,122	9,392	425,534	113,405
1994	244,848	8,093	418,419	153,860
1995	286,987	14,200	422,497	143,497
1996	286,933	13,226	422,468	159,698
1997	280,337	14,254	417,995	159,335
1998	301,910	15,424	424,664	142,324
1999	317,005	25,474	415,579	159,531
2000	338,365	32,773	415,236	159,698
2001	371,767	38,986	409,753	142,325
2002	364,118	34,363	412,100	159,531
2003	359,208	24,644	479,324	159,335
2004	377,782	31,168	475,347	142,687
2005	349,170	32,166	527,473	159,531
2006	369,333	28,748	532,217	159,335

Figure 3.2
Total Fuel Costs: Comparison of Utility Case with PUC Staff Base Case for TU Electric Company

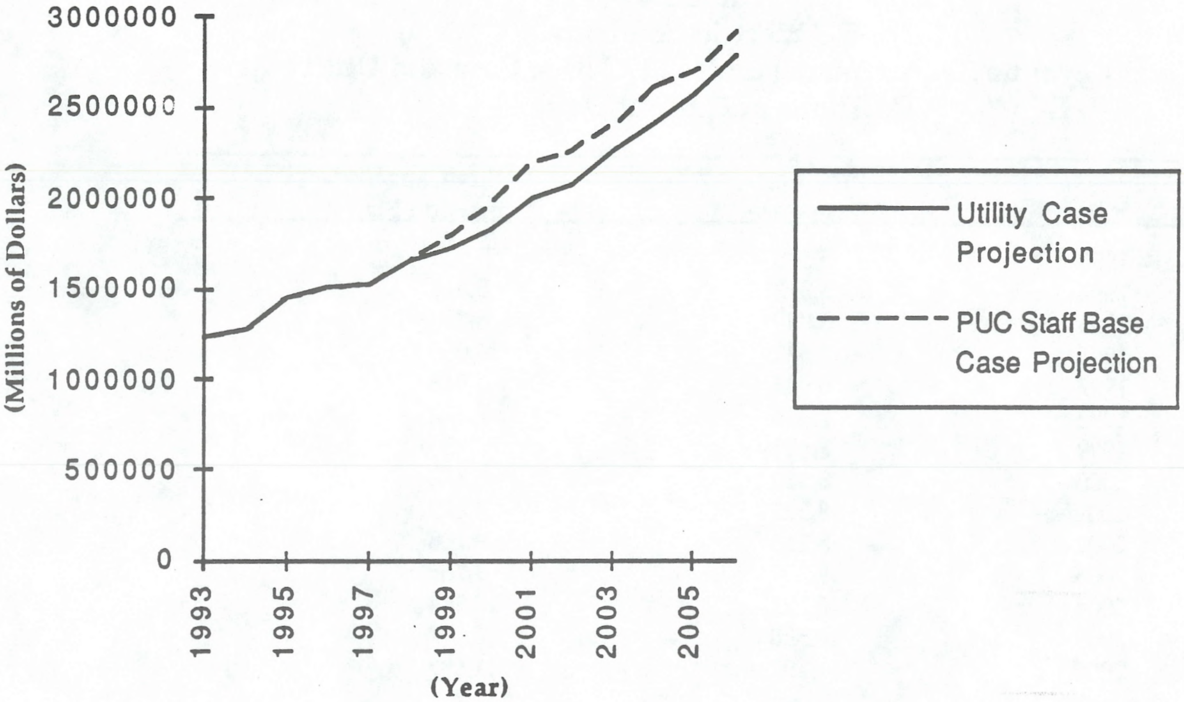


Figure 3.3
Projected Fuel Consumption PUC Base Case Scenario: TU Electric Company

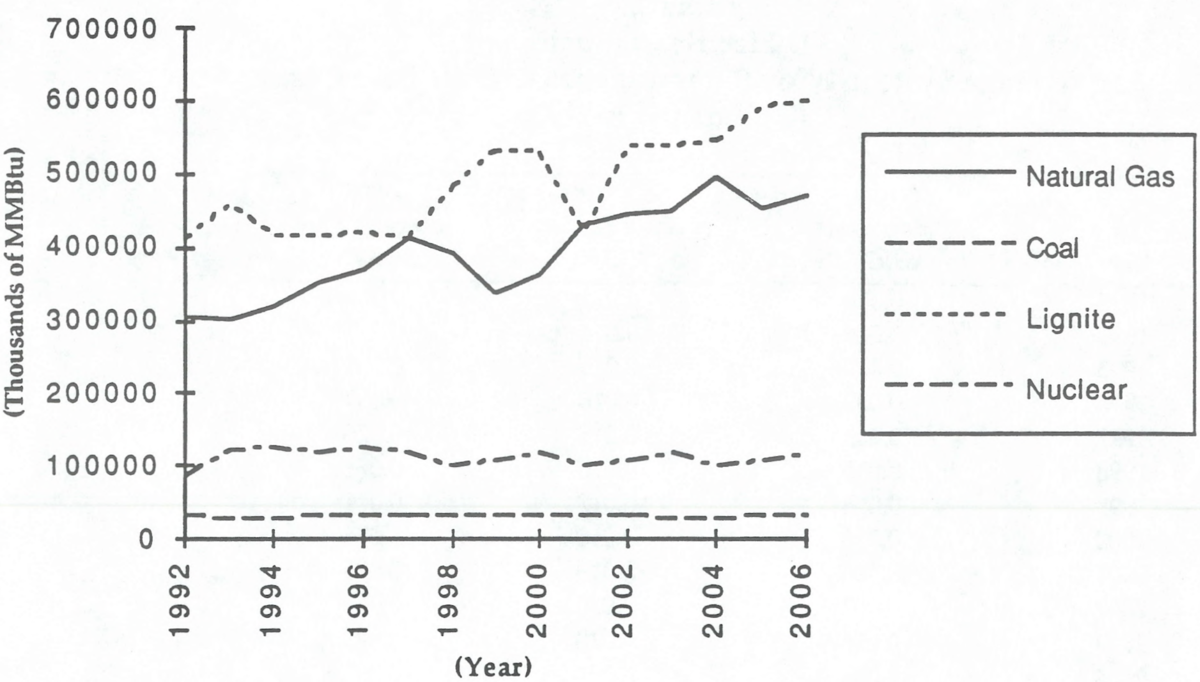


Table 3.6
TU Electric Company
Total Revenue Requirements under PUC Base Case and Utility Case
(Millions of Current Dollars)

Year	PUC Staff Base Case	Utility Capacity Expansion Plan
1993	5,508	5,508
1994	5,817	5,817
1995	6,089	6,089
1996	6,672	6,660
1997	6,982	6,943
1998	7,331	7,322
1999	7,621	7,656
2000	8,110	8,172
2001	8,522	8,679
2002	8,916	9,108
2003	9,389	9,766
2004	10,123	10,584
2005	10,530	10,094
2006	11,197	11,697

Table 3.7
TU Electric Company
Average System-Wide Rates under PUC Staff Base Case
(Dollars per kWh)

Year	Average Base Rate ($/kWh)	Fuel Factor $/kWh	Total Average Rate $/kWh
1993	0.048	0.014	0.062
1994	0.049	0.014	0.063
1995	0.049	0.015	0.064
1996	0.053	0.016	0.069
1997	0.055	0.015	0.070
1998	0.055	0.016	0.071
1999	0.054	0.017	0.071
2000	0.056	0.018	0.074
2001	0.056	0.019	0.075
2002	0.057	0.019	0.076
2003	0.058	0.020	0.078
2004	0.061	0.021	0.082
2005	0.062	0.021	0.083
2006	0.064	0.022	0.086

Table 3.8
TU Electric Company
Average System-Wide Rates under Utility Case
(Dollars per kWh)

Year	Average Base Rate ($/kWh)	Fuel Factor ($/kWh)	Total Average Rate ($/kWh)
1993	.048	.014	.062
1994	.049	.014	.063
1995	.049	.015	.064
1996	.052	.016	.068
1997	.054	.015	.069
1998	.055	.016	.071
1999	.056	.016	.072
2000	.057	.017	.074
2001	.058	.018	.076
2002	.060	.018	.078
2003	.062	.019	.081
2004	.065	.020	.085
2005	.067	.020	.087
2006	.069	.021	.090

3.3 Hypothetical DSM Program

Five hypothetical DSM programs were screened using LMSTM to identify opportunities for additional cost-effective DSM on the TU Electric Company system and provide a conservative or minimum estimate of the impact of further DSM on the utility's projected load. These five programs are:

- A refrigerator efficiency program;
- An air conditioner direct load control program;
- A water heater load control program;
- A contract lighting valley-filled program;
- A swimming pool timer program.

It was assumed that each program would be initiated in 1993 and would continue through 2006.

In performing the benefit-cost screening analysis, it was assumed that each DSM program would have no capacity value until 1996, the first year in which the utility's reserve margin is expected to slip below 19 percent under PUC staff base case assumptions.

The resulting benefit-cost ratios are presented in Table 3.9. The refrigerator efficiency program described in Chapter 2 appears to be marginally economical from the total resource perspective. The air conditioner direct load control, water heater load control, and the contract lighting programs failed to pass the benefit-cost tests. The hypothetical swimming pool program appears to be economical from either perspective.

The projected load and consumption impacts for the two programs that passed the benefit-cost tests are reported in Tables 3.10 and 3.11, respectively. The coincident peak demand reduction attributable to the two programs is expected to exceed 38 MW by 2006.

Table 3.9
TU Electric Company
Benefit-Cost Ratios for Hypothetical DSM Programs

DSM Program	Utility Test	Total Resource Test
Refrigerator Efficiency	0.89	1.03
Air Conditioner Direct Load Control	0.56	0.63
Water Heater Load Control	0.38	0.43
Contract Lighting	0.01	0.01
Swimming Pool Timer	1.56	1.80

Table 3.10
TU Electric Company
Peak Demand Impact of Hypothetical DSM Programs
Which Pass the Total Resource Cost Test
(MW)

Year	Refrigerator Efficiency	Swimming Pool Timer	Total
1993	(2)	0	(2)
1994	(3)	0	(3)
1995	(4)	(1)	(5)
1996	(5)	(2)	(7)
1997	(6)	(6)	(12)
1998	(7)	(9)	(16)
1999	(8)	(13)	(21)
2000	(9)	(18)	(27)
2001	(11)	(22)	(33)
2002	(12)	(22)	(34)
2003	(13)	(22)	(35)
2004	(14)	(22)	(36)
2005	(15)	(22)	(37)
2006	(16)	(22)	(38)

Table 3.11
TU Electric Company: Energy Impact of Hypothetical DSM Programs
Which Pass the Total Resource Cost Test
(MWH at meter)

Year	Refrigerator Efficiency	Swimming Pool Timer	Total
1993	(17,000)	0	(17,000)
1994	(26,000)	0	(26,000)
1995	(34,000)	0	(34,000)
1996	(43,000)	(1,000)	(44,000)
1997	(51,000)	(2,000)	(53,000)
1998	(60,000)	(3,000)	(63,000)
1999	(69,000)	(5,000)	(74,000)
2000	(77,000)	(7,000)	(84,000)
2001	(86,000)	(8,000)	(94,000)
2002	(94,000)	(8,000)	(102,000)
2003	(103,000)	(8,000)	(111,000)
2004	(111,000)	(8,000)	(119,000)
2005	(120,000)	(8,000)	(128,000)
2006	(129,000)	(8,000)	(137,000)

It must be emphasized that these two programs are not necessarily recommended for implementation. A more comprehensive screening analysis or a solicitation for resources may identify more economical or beneficial DSM strategies. These two programs merely represent a minimal suggested contribution of additional DSM resources supported by the limited analysis conducted here.

The impacts on system reserve margins by adding the refrigerator efficiency and swimming pool timer programs to the PUC base case plan are shown in Table 3.12. The addditional DSM programs lower system peak demands, resulting in higher reserve margin percentages than those of the original PUC base case (see Table 3.3). Additional DSM resources could alter the optimal expansion plan of the PUC base case by delaying the on-line dates of future units, but this analysis was not performed because of time limitations.

Table 3.12
TU Electric Company: Impact on Reserve Margin of Additional DSM in the PUC Base Case Resource Plan

Year	PUC Staff Adjusted System Peak (MW)	Additional DSM (MW)	Installed Capacity (MW)	Firm Purchases (MW)	Net System Capacity (MW)	Reserve Margin (%)
1993	17,643	2	21,078	1,771	22,847	29.5
1994	18,003	3	21,076	1,771	22,847	26.9
1995	18,548	5	21,076	1,421	22,497	21.3
1996	19,095	7	21,076	1,454	22,530	18.0
1997	19,575	12	21,366	1,994	23,360	19.4
1998	19,969	16	21,366	2,244	23,610	18.3
1999	20,421	21	22,011	2,084	24,095	18.1
2000	20,895	27	22,656	2,010	24,666	18.2
2001	21,317	33	22,928	2,224	25,152	18.2
2002	21,800	34	23,548	2,455	26,003	19.5
2003	22,252	35	24,084	2,321	26,405	18.9
2004	22,728	36	24,287	2,595	26,882	18.5
2005	23,198	37	24,797	2,599	27,396	18.3
2006	23,617	38	25,214	2,652	27,866	18.2

3.4 Alternative Capacity Expansion Plans for TU Electric

This section describes the results of another alternative capacity expansion scenario (Scenario 3) and compares these results to the PUC base case scenario (Scenario 1) and the utility case scenario (Scenario 2) described in section 3.1. All three scenarios adopt the Commission staff's demand, fuel price, DSM program impact projections, and firm cogeneration purchase projections. Scenario 3 was obtained as the optimal expansion plan using PROVIEW, where the objective was to determine the expansion plan that gives the lowest present value of revenue requirements over the study period (which consisted of a planning period from 1993 to 2006, and an extension period of 15 years).

In this scenario, the earliest commissioning date that a unit could be brought on-line was the earlier of the on-line dates for the corresponding unit in Scenario 1 and Scenario 2. The reserve margin was constrained to be at least 18 percent. Environmental impacts and fuel mix considerations were ignored in the optimization process. Tables 3.13 through 3.17 and Figure 3.4 show comparisons of the three scenarios. Of course, Scenario 3 results in the lowest present value of revenue requirements over the study period, but the PUC base case scenario (Scenario 1) has revenue requirements and average rates over the planning period that are very close to those of Scenario 3, as shown in Tables 3.16 and 3.17. Given the emissions constraints under which TU Electric must now operate, it may turn out that the PUC base case scenario is more attractive than the other two scenarios.

Table 3.13
TU Electric Company
Assumed On-Line Dates for Capacity Additions under Alternative Scenarios

On-Line Date Under PUC Staff Base Case Scenario	On-Line Date Assumed in Scenario No. 2	On-Line Date Assumed in Scenario No. 3	Plant Name	Unit No.	Net MW Owned	Primary Fuel
1993	1993	1993	Comanche Peak	2	1,150	URAN
2003	1999	1999	Twin Oak	1	750	LIG
2005	2000	2000	Twin Oak	2	750	LIG
1999	2001	2005	Undesignated CC (CCCT1)	1	645	NG
2000	2002	2006	Undesignated CC (CCCT2 1)	1	645	NG
1997	1998	1997	Undesignated CT (COMBS001)	2	145	NG
1997	1998	1997	Undesignated CT (COMBS002)	1	145	NG
2002	2005	2002	Undesignated CC (CCCT 3 1)	1	620	
>2006	2003	>2006	Forest Grove	1	660	LIG/SUB
>2006	2004	>2006	Pulverized Coal Unit	1	650	LIG/SUB
2004	2006	2003	Undesignated CC (CCCT4 1)	1	620	NG
2001	2003	2001	Undesignated CT (COMBS014)	1	136	NG
2001	2003	2001	Undesignated CT (COMBS021)	2	136	NG
2003	2004	2003	Undesignated CT (COMBS022)	1	136	NG
2003	2004	2003	Undesignated CT (COMBS023)	2	136	NG
2005	2004	2005	Undesignated CT (COMBS024)	1	136	NG
2005	2005	2005	Undesignated CT (COMBS025)	2	136	NG
2006	2009	2004	Undesignated CC (CCCT 5 1)	1	620	NG
2006	2005	2006	Undesignated CT (COMBS026)	1	136	NG
2006	2006	2006	Undesignated CT (COMBS027)	2	136	NG
>2006	2006	>2006	Undesignated CT (COMBS028)	1	136	NG

NOTE: The utility-planned commercial operation date and on-line date under PUC staff base case scenario refer to the year in which peak demand will first be served by the unit.

Table 3.14
TU Electric Company: Comparison of Capacity Additions and Reserve Margins under Alternative Planning Scenarios

Year	Scenario #1 PUC Base Case		Scenario #2 Utility Case		Scenario #3 Capacity Expansion Case	
	Capacity Addition	Reserve Margin (%)	Capacity Addition	Reserve Margin (%)	Capacity Addition	Reserve Margin (%)
1993	1,150	29.5	1,150	29.5	1,150	29.5
1994	0	25.0	0	25.0	0	25.0
1995	0	20.8	0	20.8	0	20.8
1996	0	18.0	0	18.0	0	18.0
1997	290	19.3	0	17.9	290	19.3
1998	0	18.2	290	18.2	0	18.2
1999	645	18.0	750	18.5	750	18.5
2000	645	18.1	750	19.1	750	19.1
2001	272	18.0	645	20.7	272	19.0
2002	620	19.3	645	22.1	620	20.3
2003	1,022	18.7	932	21.0	892	19.0
2004	620	18.3	1,058	22.5	620	18.6
2005	1,022	18.1	892	21.7	917	18.0
2006	892	18.0	892	21.5	917	18.0

Table 3.15
TU Electric Company: Total Fuel Costs under Alternative Planning Scenarios (Thousands of Dollars)

Year	Scenario #1 PUC Staff Base Case	Scenario #2 Utility Capacity Expansion Plan	Scenario #3 Capacity Expansion Plan
1993	1,234,580	1,234,580	1,234,580
1994	1,281,552	1,281,552	1,281,552
1995	1,458,465	1,458,465	1,458,465
1996	1,506,004	1,506,004	1,506,004
1997	1,525,512	1,524,439	1,525,512
1998	1,650,750	1,650,750	1,650,750
1999	1,795,092	1,728,206	1,728,206
2000	1,968,872	1,829,731	1,829,731
2001	2,187,477	2,002,106	2,034,288
2002	2,259,068	2,081,067	2,104,513
2003	2,411,599	2,260,951	2,325,436
2004	2,609,369	2,413,451	2,515,924
2005	2,694,040	2,571,310	2,689,511
2006	2,917,466	2,788,269	2,917,466

Table 3.16
TU Electric Company
Total Revenue Requirements underAlternative Planning Scenarios
(Millions of Current Dollars)

Year	Scenario #1 PUC Staff Base Case	Scenario #2 Utility Capacity Expansion Plan	Scenario #3 Capacity Expansion Plan
1993	5,508	5,508	5,508
1994	5,817	5,817	5,817
1995	6,089	6,089	6,089
1996	6,672	6,660	6,661
1997	6,982	6,943	6,963
1998	7,331	7,322	7,323
1999	7,621	7,656	7,626
2000	8,110	8,172	8,149
2001	8,522	8,679	8,580
2002	8,916	9,108	8,965
2003	9,389	9,766	9,419
2004	10,123	10,584	10,036
2005	10,530	10,094	10,513
2006	11,197	11,697	11,133

Figure 3.4
TU Electric Company: Total Revenue Requirements under Alternative Planning Scenarios

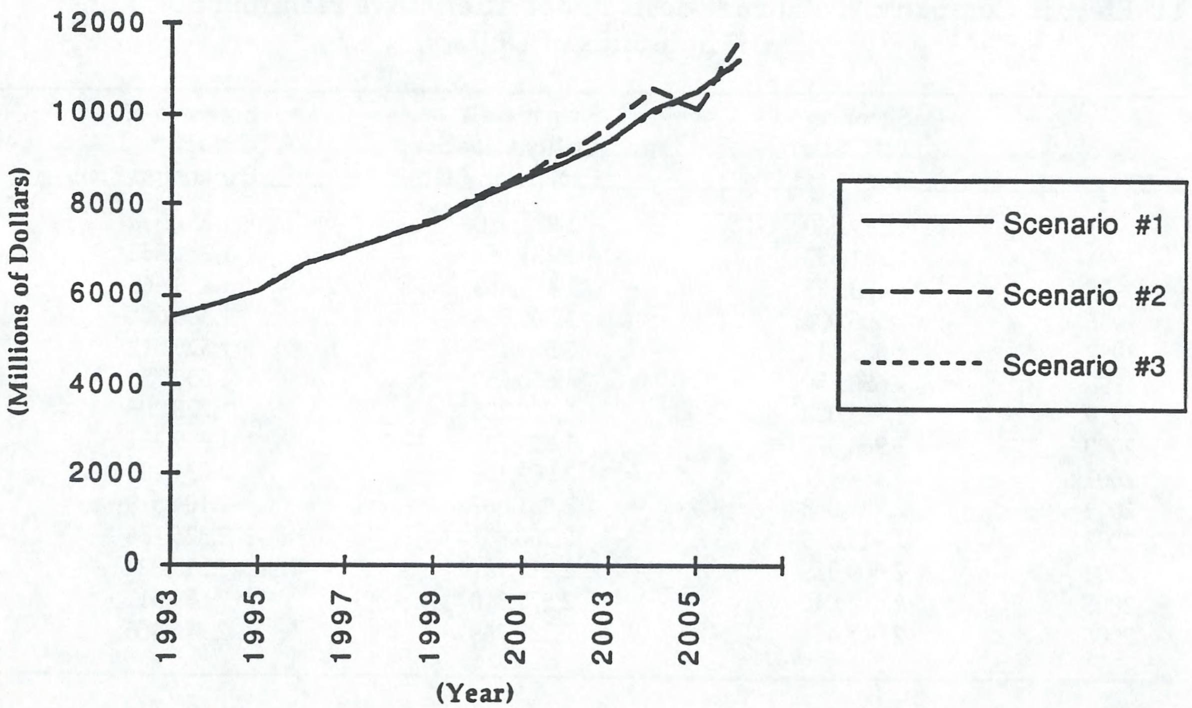


Table 3.17
TU Electric Company
Average Rates under Alternative Planning Scenarios
(Cents per kWh)

Year	Scenario #1 PUC Staff Base Case	Scenario #2 Utility Capacity Expansion Plan	Scenario #3 Capacity Expansion Plan
1993	6.15	6.15	6.15
1994	6.33	6.33	6.33
1995	6.42	6.42	6.42
1996	6.85	6.84	6.84
1997	6.96	6.92	6.94
1998	7.08	7.07	7.08
1999	7.14	7.17	7.14
2000	7.36	7.41	7.39
2001	7.50	7.63	7.55
2002	7.61	7.78	7.66
2003	7.78	8.10	7.81
2004	8.17	8.54	8.10
2005	8.28	8.72	8.26
2006	8.57	8.95	8.52

CHAPTER 4

HOUSTON LIGHTING AND POWER COMPANY

4.1 Introduction

Houston Lighting and Power Company (HL&P) is presently planning a number of additions to generating capacity over the next fifteen years. The analysis presented here indicates that increased reliance upon cogeneration (relative to the utility's present resource plan) may provide economical opportunities to defer many of the generating units currently planned by the utility. Further, DSM program screening exercises indicate that there may be cost-effective opportunities to reduce future demand beyond the energy efficiency goals presently established by HL&P. In light of the utility's anticipated capacity needs, further evaluation of DSM strategies designed to impact summer peak demand may be particularly warranted.

4.2 PUC Staff Base Case

Development of the PUC staff base case for HL&P relies upon the PUC staff's independent demand and fuel price projections, the staff's projections of the impacts of the utility's existing and planned demand-side management efforts, and the resource plan presented by the Commission staff in Docket No. 11000. The PUC's staff load projections are slightly higher than HL&P's, as indicated in Figures 4.1 and 4.2. The PUC staff's fuel price forecasts are significantly lower than the utility's for natural gas, coal, and lignite.

Table 4.1 contrasts the utility's capacity expansion plan with PUC base case capacity expansion assumptions. The on-line dates for the DuPont joint venture and upgrades to existing plants were not changed. However, most of the remaining utility-planned capacity additions were deferred under the PUC staff base case. The deferred units include Malakoff, Greens Bayou units 3 and 4, Webster units 1 and 2, and a number of unspecified combined cycle natural gas fired units.

Figure 4.1
Comparison of PUC Staff and Utility-Developed Peak Demand Projections: Houston Lighting & Power Company

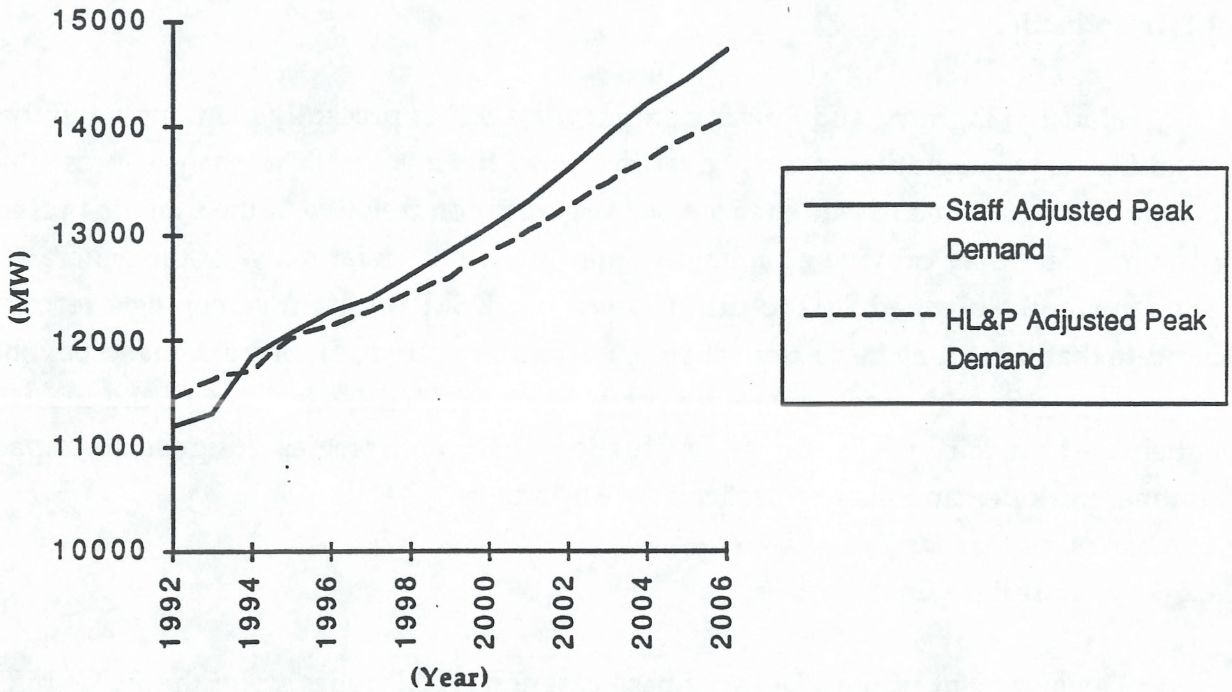


Figure 4.2
Comparison of PUC Staff and Utility-Developed Sales Projections: Houston Lighting and Power Company

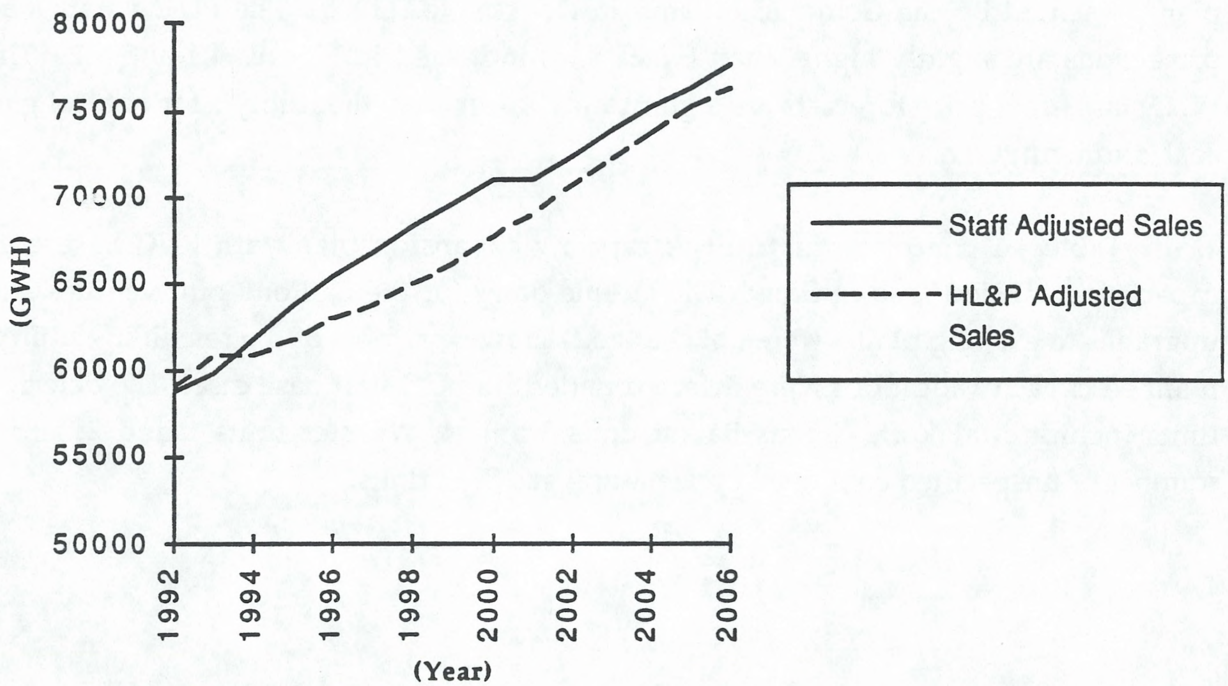


Table 4.1
Houston Lighting and Power Company
Planned Capacity Additions

Utility's Planned Commercial Operation Date	On-Line Date Assumed in PUC Base Case	Plant Name	Unit #	Regulatory Status	Net MW Owned	Primary Fuel	$/kW Including AFUDC
1992	1992	UPGRADE	-	-	20	NG	-
1993	1993	UPGRADE	-	-	30	NG	-
1993	1993	UPGRADE	-	-	40	COAL	-
1994	1994	UPGRADE	-	-	10	NG	-
1995	1995	UPGRADE	-	-	10	NG	-
1995	1995	DU PONT	-	NOI	158	NG	766
1996	1996	UPGRADE	-	-	10	NG	-
1996	1998	WEBSTER	1	NOI	110	NG	321
1996	1998	WEBSTER	2	NOI	110	NG	-
1998	2002	(CCGTE01)	1	-	219	NG	644
1998	2001	GREENS BAYOU	3	NOI	110	NG	416
1998	2001	GREENS BAYOU	4	NOI	110	NG	-
2000	2003	(CCGTF01)	2	-	206	NG	650
2000	2003	(CCGTF02)	3	-	206	NG	650
2001	2004	(CCGTF03)	4	-	206	NG	650
2002	2005	(CCGTF04)	5	-	206	NG	650
2002	2006	(CCGTF05)	6	-	206	NG	650
2003	2006	(CCGTF06)	7	-	206	NG	650
2004	>2006	(CCGTF07)	8	-	206	NG	650
2005	>2006	MALAKOFF	1	CCN	645	LIG	2,484
2006	>2006	(CCGTF08)	9	-	206	NG	650
2006	>2006	(CCGTF09)	10	-	206	NG	650
2006	>2006	(CCGTF10)	11	-	206	NG	650

KEY: NG=Natural Gas LIG=Lignite NOI=Notice of Intent CCN=Certificate of Convenience and Necessity

Purchases of firm cogeneration are assumed to provide an opportunity to defer many of the utility's planned capacity additions under the PUC staff base case scenario. As indicated in Table 4.2, reliance upon firm cogeneration would increase to 1,640 MW by 2005 under PUC staff base case assumptions.

Table 4.2
Houston Lighting and Power Company
Purchases of Firm Cogeneration under Utility and PUC Staff Base Case Planning Assumptions
(MW)

Year	Utility Projection	Additional Purchased under PUC Staff Base Case	Total Purchases under PUC Staff Base Case
1991	945	0	945
1992	945	0	945
1993	945	0	945
1994	720	0	720
1995	395	0	395
1996	395	170	565
1997	395	315	710
1998	270	560	830
1999	270	750	1,020
2000	270	1,030	1,300
2001	270	1,090	1,360
2002	270	1,225	1,495
2003	270	1,225	1,495
2004	270	1,310	1,580
2005	0	1,640	1,640
2006	0	1,640	1,640

The PUC staff base case also assumes that HL&P will increase its reliance upon DSM beyond its present energy efficiency goals. To derive a suggested minimum additional contribution of DSM to the HL&P system, five hypothetical DSM programs were screened using LMSTM:

- A refrigerator efficiency program;
- An air conditioner load control program;
- A water heater load control program;
- A swimming pool timer program; and
- A commercial sector lighting program.

It was assumed that each program would be initiated in 1992 and would continue through 2006. It was determined that each DSM program would have capacity value in each year from 1997 through 2006. Projected reserve margins and near-term commitments to increase capacity deemed to be unavoidable (for the purposes of this analysis) limit the capacity value of DSM programs in earlier years.

LMSTM's post-processor, DISPLAY, was used to calculate benefit-cost ratios for each of the hypothetical DSM programs. Because DISPLAY cannot easily take into consideration the capacity value of DSM programs, an additional post-processor was developed by CES to add the capacity value of the DSM program being analyzed to the benefits calculation performed by DISPLAY. The benefit-cost ratios were then recalculated with capacity values included. A DSM program received capacity value only in those years when additional capacity appeared to have value.

Benefit-cost ratios for the five hypothetical DSM programs are reported in Table 4.3. Aside from the Water Heater Load Control program, each of the five programs passed the total resource cost test and was included in the PUC staff base case scenario. The impacts on system load of each program that passed the total resource test are presented in Tables 4.4 and 4.5.

Table 4.3
Houston Lighting and Power Company
Benefit-Cost Ratios for Hypothetical DSM Programs

DSM Program	Utility Test	Total Resource Test
Refrigerator Efficiency	0.87	1.01
Air Conditioner Direct Load Control	0.92	1.23
Water Heater Load Control	0.48	0.77
Swimming Pool Timers	2.59	3.01
Commercial Sector Lighting T-8	10.30	10.30
T-10	3.97	3.97

Table 4.4
Houston Lighting and Power Company Peak Demand Impact of Hypothetical DSM Programs That Pass the Total Resource Cost Test (MW)

Year	Refrigerator Efficiency	AC Load Control	Swimming Pool Timer	Commercial Lighting T-8 & T-10	Total
1992	(1)	(7)	0	(1)	(9)
1993	(1)	(32)	0	(4)	(37)
1994	(2)	(70)	0	(7)	(79)
1995	(2)	(92)	(1)	(10)	(105)
1996	(3)	(104)	(2)	(13)	(122)
1997	(3)	(104)	(6)	(16)	(129)
1998	(4)	(104)	(9)	(19)	(136)
1999	(4)	(104)	(13)	(19)	(140)
2000	(5)	(104)	(18)	(19)	(146)
2001	(6)	(104)	(22)	(19)	(151)
2002	(6)	(104)	(22)	(19)	(151)
2003	(7)	(104)	(22)	(19)	(152)
2004	(7)	(104)	(22)	(19)	(152)
2005	(8)	(104)	(22)	(19)	(153)
2006	(8)	(104)	(22)	(19)	(153)

Table 4.5
Houston Lighting and Power Company Energy Impact of Hypothetical DSM Programs That Pass the Total Resource Cost Test (MWH)

Year	Refrigerator Efficiency	AC Load Control	Swimming Pool Timer	Commercial Lighting T-8 & T-10	Total
1992	(5,000)	0	0	(4,000)	(9,000)
1993	(9,000)	0	0	(12,000)	(21,000)
1994	(13,000)	0	0	(20,000)	(33,000)
1995	(18,000)	0	0	(29,000)	(47,000)
1996	(22,000)	0	(1,000)	(39,000)	(62,000)
1997	(27,000)	0	(2,000)	(49,000)	(78,000)
1998	(31,000)	0	(3,000)	(59,000)	(93,000)
1999	(36,000)	0	(5,000)	(59,000)	(100,000)
2000	(40,000)	0	(7,000)	(59,000)	(106,000)
2001	(45,000)	0	(8,000)	(59,000)	(112,000)
2002	(49,000)	0	(8,000)	(59,000)	(116,000)
2003	(54,000)	0	(8,000)	(59,000)	(121,000)
2004	(58,000)	0	(8,000)	(59,000)	(125,000)
2005	(63,000)	0	(8,000)	(59,000)	(130,000)
2006	(67,000)	0	(8,000)	(59,000)	(134,000)

Inclusion of these five hypothetical DSM programs in the PUC staff base case scenario is not meant to imply that these necessarily are recommended additions to HL&P's program offerings. Indeed, a more comprehensive screening analysis or a solicitation for additional resources is likely to identify other, still more promising, DSM opportunities. These programs merely provide a minimum additional DSM program impact which could be supported through the limited analysis conducted here.

Table 4.6 provides a reserve margin for the PUC staff base case scenario, taking into consideration the assumptions stated above regarding the on-line dates for capacity additions, cogeneration dependence, and additional DSM activity.

Table 4.6
Reserve Margin Calculation
Under PUC Staff Base Case Assumptions
for Houston Lighting and Power Company

Year	PUC Staff Adjusted System Peak (MW)	Additional DSM (MW)	Installed Capacity (MW)	Firm Purchases (MW)	Net System Capacity (MW)	Reserves Margin (%)
1992	11,193	9	13,624	945	14,569	30.0
1993	11,311	37	13,679	945	14,624	29.0
1994	11,848	79	13,734	720	14,454	22.0
1995	12,075	105	13,907	395	14,302	18.0
1996	12,270	122	13,922	565	14,487	18.0
1997	12,398	129	13,922	710	14,632	19.0
1998	12,627	136	14,142	830	14,972	20.0
1999	12,843	140	14,142	1,020	15,162	19.0
2000	13,079	146	14,142	1,300	15,442	19.0
2001	13,323	151	14,362	1,360	15,722	19.0
2002	13,623	151	14,581	1,495	16,076	19.0
2003	13,929	152	14,993	1,495	16,488	20.0
2004	14,220	152	15,199	1,580	16,779	19.0
2005	14,444	153	15,405	1,640	17,045	19.0
2006	14,730	153	15,771	1,640	17,411	19.0

Projected fuel costs resulting from the PUC staff base case scenario are presented in Table 4.7 and Figure 4.3. The fuel cost projections resulting from PUC staff base case assumptions are actually lower than the utility's fuel cost projections through 1998. Beyond that year, the utility's projections grow at a much greater rate. Projected fuel consumption is presented in Table 4.8 and Figure 4.4.

Table 4.7
Total Fuel Costs
Comparison of Utility Projection with
PUC Staff Base Case Projection
Houston Lighting and Power Company
(Thousands of Dollars)

Year	Utility Projection (August 1992)	PUC Staff Base Case Projection
1992	906,997	1,220,362
1993	1,000,257	1,276,506
1994	1,075,295	1,359,300
1995	1,199,228	1,379,179
1996	1,377,543	1,440,989
1997	1,513,982	1,517,474
1998	1,704,637	1,565,039
1999	1,846,925	1,628,289
2000	1,969,251	1,685,206
2001	2,158,234	1,789,917
2002	2,355,913	1,883,399
2003	2,560,457	1,836,129
2004	2,796,046	1,938,881
2005	3,048,544	1,899,585
2006	3,331,158	2,021,339

Figure 4.3
Total Fuel Costs Comparison of Utility Projection with PUC Staff Base Case Projection: Houston Lighting and Power Company

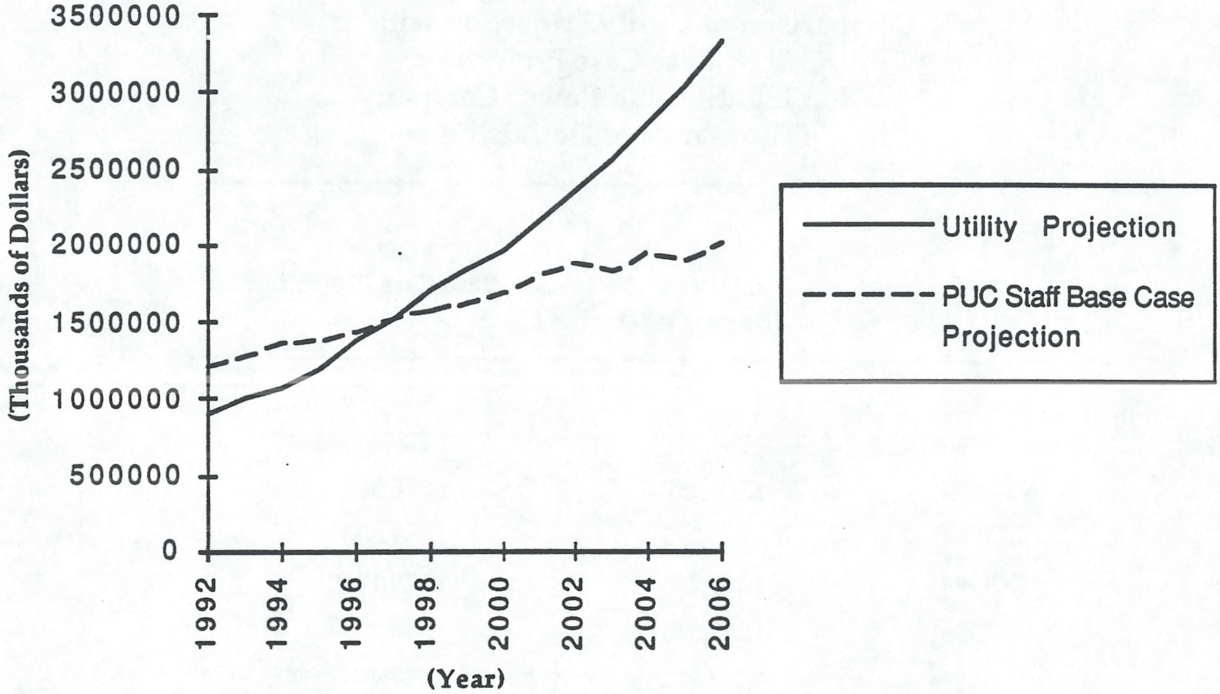


Figure 4.4
Projected Fuel Consumption under PUC Staff Base Case Assumptions: Houston Lighting and Power Company

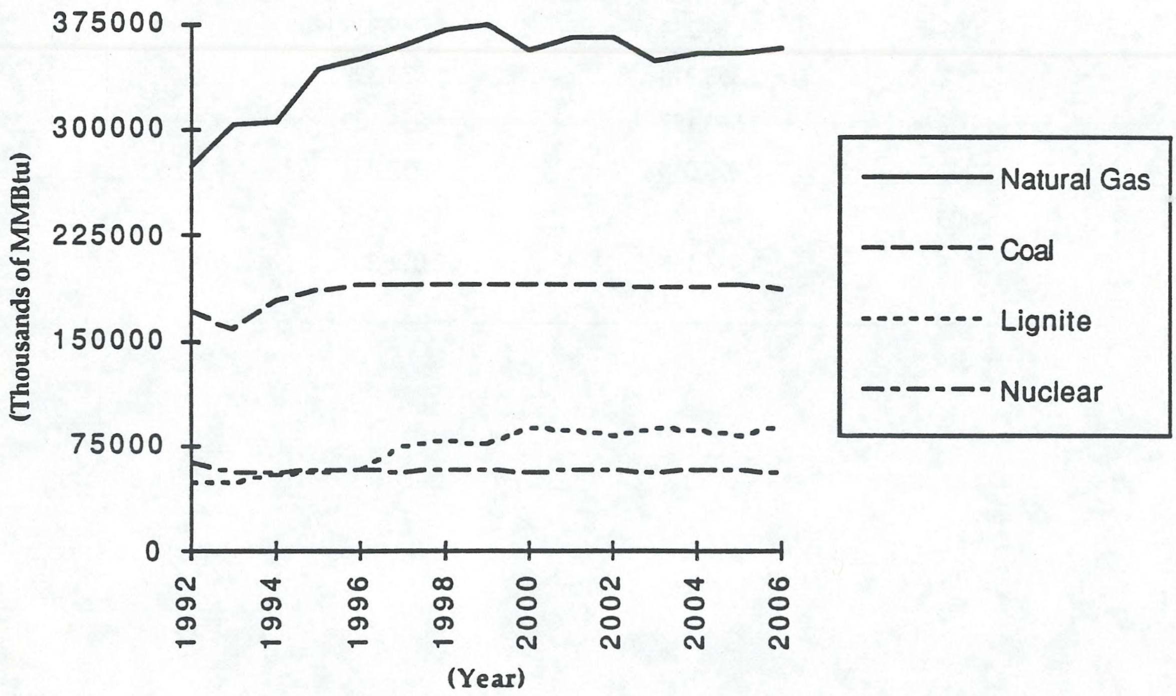


Table 4.8
Houston Lighting and Power Company
Projected Fuel Consumption under
PUC Staff Base Case Assumptions
(Thousands of MMBtu)

Year	Natural Gas	Coal	Lignite	Nuclear
1992	274,799	171,259	49,495	63,516
1993	304,583	157,850	48,746	56,942
1994	305,204	179,136	53,259	56,648
1995	341,930	187,052	56,773	57,399
1996	351,122	190,892	58,701	58,184
1997	359,046	189,405	74,292	56,648
1998	369,857	189,539	78,441	57,399
1999	374,581	190,892	76,017	58,184
2000	355,253	189,399	87,172	56,648
2001	365,533	189,539	86,097	57,399
2002	365,495	190,801	82,601	58,184
2003	349,250	188,800	87,407	56,648
2004	353,532	188,336	84,966	57,399
2005	353,894	189,383	82,469	58,184
2006	357,545	186,352	89,073	56,632

System-wide average rates are projected to increase from their present level of 6 cents per kWh to 8.5 cents per kWh by 2006, as reported in Table 4.9. Base rates and fuel factor charges are projected to increase at similar growth rates under PUC staff base case assumptions.

Table 4.9
Houston Lighting and Power Company
Projected System-Wide Rates under PUC Staff Base Case Assumptions
(Dollars per kWh)

Year	Average Base Rate	Fuel Factor	Total Average Rate
1992	0.039	0.021	0.060
1993	0.041	0.021	0.062
1994	0.040	0.022	0.062
1995	0.040	0.022	0.062
1996	0.040	0.023	0.063
1997	0.040	0.024	0.064
1998	0.041	0.025	0.066
1999	0.042	0.026	0.068
2000	0.042	0.027	0.069
2001	0.043	0.028	0.071
2002	0.045	0.030	0.075
2003	0.048	0.029	0.077
2004	0.049	0.031	0.080
2005	0.051	0.031	0.082
2006	0.052	0.033	0.085

4.3 Existing and Planned Demand-Side Management Programs

In the PUC staff base case scenario, existing and planned DSM programs were explicitly modeled in LMSTM. Explicit modeling is necessary to develop an accurate system load curve and assists in determining the impact and economics of individual programs. A list of existing and utility-proposed DSM programs is presented in Table 4.10.

Table 4.10
Houston Lighting and Power Company
Demand Side Management Programs

Program Name	Status
Good Cents New Home Program	Existing
Good Cents Apartment Program	Existing
Good Cents Apartment Program—EEHVAC	Existing
Contract Lighting Service Program	Existing
Commercial Efficiency Improvement Program	Existing
EEHVAC Program-Retrofit	Existing
Energy Check-up Program	Existing
Commercial Cool Storage Program	Existing
Good Cents New Home—EEHVAC	Existing
Residential Direct Load Control Program	Proposed
Industrial Efficiency Improvement Program	Proposed
Good Cents Improved Home Program	Proposed

In many cases, the existing DSM programs combine a number of end-uses and options. Since program participation and cost data are presented for the aggregate DSM program, data are insufficient to determine these program costs by end-use or option. Therefore, existing programs are modeled in aggregate. Although this method simplifies the use of participation, utility, and customer cost data, difficulties are created in determining aggregate program loadshapes.

For some of the programs modeled, the Commission staff requested that changes be made to data reported by the utilities in their Energy Efficiency Plans. In these cases, the Commission staff believed that the utilities had not accounted for "free ridership," or that estimates of impacts appeared to be inflated due to other factors. The modeling of DSM programs reflects the changes requested by the Commission staff.

Participation data are only given through 1999 in the Energy Efficiency Plan, so participant numbers for the years 2000 through 2006 are assumed to grow at the rate specified for 1999. Program expense data are also assumed to remain at the level given in the last year specified. Costs that remained constant as participant numbers varied were classified as fixed costs. Expenses that seemed to vary in proportion to the number of participants were set up to vary with the number of customers throughout the life of the program; these are specified on a per participant basis.

Transmission and distribution system losses were obtained from Schedule P-9 from the utility's latest rate filing package. The demand loss factor was used for summer peak days. The energy loss factor was used for all other day types.

Normalized DSM program loadshapes were received from HL&P for 1991. Since these were primarily detailed by end-use, aggregation of pertinent loadshapes was required. A weighted average (by participation rates as defined in the HL&P Energy Efficiency Plan) was used to combine loadshapes. The distribution of program participants among available end-use options was assumed to remain constant throughout the modeling period.

Program loadshapes were then calibrated to the peak and energy savings estimates obtained from the PUC. This was accomplished by using a combination of available utility and PUC data. For loadshapes submitted with only two day types (weekend and high days), a non-peak day was created by linearly reducing the high-day loadshape by a factor appropriate for the program.

To judge the cost effectiveness of various DSM programs, a benefit-cost analysis was performed for each program from the utility cost and the total resource cost perspective. This was done by running LMSTM output through its impact analysis module, DISPLAY, to get a benefit-cost ratio based on all benefits and costs other than avoided capacity benefits. These figures were then transferred to a spreadsheet that incorporated the avoided capacity costs as an additional benefit and recalculated the ratios. The results of this analysis are illustrated in Table 4.11.

Table 4.11
Benefit-Cost Ratios for Houston Lighting and Power Company's Existing DSM Programs

DSM Program	Utility Costs	Benefits	Total Resource Impact Cost	Benefits	Average (kW) Impact 1995-2006
Commercial Efficiency Improvement	7.098	31.576	57.349	31.58	34,167
Industrial Efficiency Improvement	5.773	3.793	5.773	3.793	96,583
Commercial/Industrial Undefined	N/A	N/A	N/A	N/A	N/A
Commercial Cool Storage	32.386	0.223	0.223	0.223	76,833
Contract Lighting Service	16.411	0.011	21.944	0.011	0
Good Cents EEHVAC Existing	16.329	14.572	37.797	14.57	27,833
Good Cents EEHVAC New	26.563	0.026	57.081	0.026	6,917
Good Cents New Home	21.35	2.029	17.428	2.029	12,417
Good Cents Existing Home	4.866	4.133	6.454	4.133	8,583
Good Cents Apartment	5.119	1.555	9.636	1.555	625

Benefit/Cost Ratios:

DSM Program	Utility Cost	Total Resource Cost
Commercial Efficiency Improvement Program	9.01	1.12
Industrial Efficiency Improvement Program	16.52	16.52
Commercial/Industrial Undefined Program	N/A	N/A
Commercial Cool Storage Program	2.26	1.48
Contract Lighting Service Program	0.0	0.0
Good Cents EEHVAC Existing Program	2.51	1.08
Good Cents EEHVAC New Program	0.25	0.12
Good Cents New Home Program	0.65	0.79
Good Cents Existing Home Program	2.52	1.90
Good Cents Apartment Program	0.97	0.73

The Commercial/Industrial Efficiency, Commercial Cool Storage, and Good Cents Existing Home and Existing EEHVAC programs all seem to be cost effective as measured by the utility cost and total resource cost tests. The cost-effectiveness estimates of industrial efficiency are not reliable because this program had not begun when the latest Energy Efficiency Plan was filed, so very few cost data were specified. The economics of the Commercial/Industrial Undefined programs could not be analyzed because no cost data were available.

The Contract Lighting, Good Cents Apartment, and Good Cents New Home and New EEHVAC do not seem to be cost effective from either the total resource cost or the utility cost perspective.

4.4 Alternative Scenario: The Economics of the Utility's Present Resource Plan under PUC Staff Demand and Fuels Price Projections

As noted in Section 4.1, the PUC staff base case places significantly greater reliance upon firm cogeneration to meet expected demand growth than HL&P's present resource plan. Further, under the PUC staff base case resource plan, the Webster units are postponed by two years, the Greens Bayou plant additions are delayed by three years, the Malakoff project is deferred by at least one year, and eleven gas turbines are deferred by at least one year. This section compares the projected system costs associated with the PUC staff base case scenario to a scenario based upon the utility's proposed capacity expansion plan. Each of these alternative resource planning scenarios assumes that the PUC staff's demand and fuel price projections are realized.

Table 4.12 presents the results of this comparison. Revenue requirements are significantly lower under the Commission staff's resource plan than under the utility's. Total capacity additions (in terms of megawatts of capacity) are slightly lower under the Commission staff's resource plan, reducing capacity costs somewhat. Further, greater reliance upon cost-effective cogeneration resources was assumed in development of the PUC staff base case scenario.

Table 4.12
Comparison of Revenue Requirements from Scenarios for Houston Lighting and Power Company (Millions of Dollars)

Year	PUC Staff Base Case	Utility's Capacity Expansion Plan
1992	3,493	3,493
1993	3,699	3,699
1994	3,840	3,841
1995	3,898	3,901
1996	4,090	4,091
1997	4,271	4,279
1998	4,485	4,498
1999	4,735	4,788
2000	4,673	4,786
2001	4,868	5,017
2002	5,153	5,301
2003	5,368	5,482
2004	5,629	5,721
2005	5,831	6,028
2006	6,149	6,535

CHAPTER 5

CENTRAL POWER AND LIGHT COMPANY

5.1 Introduction

According to their latest resource plan filed at the Commission, CPL plans to repower three natural gas-fired units and participate in the development of two new baseload generating units over the next fifteen years. The utility also expects to retire five existing natural gas-fired units.

Under the PUC staff base case, Coleto Creek Unit No. 2 and the proposed SWEPCO lignite project (to be jointly owned by the Central and Southwest Corporation's operating companies under their resource plans) are either cancelled or deferred beyond the year 2006. Beginning in 2001, purchases of additional capacity from either cogenerators or other utilities will likely be required to ensure adequate system reliability.

5.2 PUC Staff Base Case

The PUC staff base case for CPL is based upon the Commission staff's projections of load, fuel prices, and DSM program impact for the utility. As indicated in Figures 5.1 and 5.2, the PUC staff's load projections begin to diverge from the utility's around 2000. The utility's planned unit additions and retirements for units other than Coleto Creek Unit No. 2 and the proposed SWEPCO lignite project, presented in Table 5.1, are used in the development of the PUC staff base case.

Four hypothetical DSM programs were screened using LMSTM to assist in determining whether more ambitious DSM efforts might prove cost-effective. These four programs, described in Chapter 2, are:

- Refrigerator efficiency
- Air conditioner direct load control
- Water heater load control
- Contract lighting

Figure 5.1
Comparison of PUC Staff and Utility-Developed Adjusted Peak Demand Projections: Central Power & Light Co.

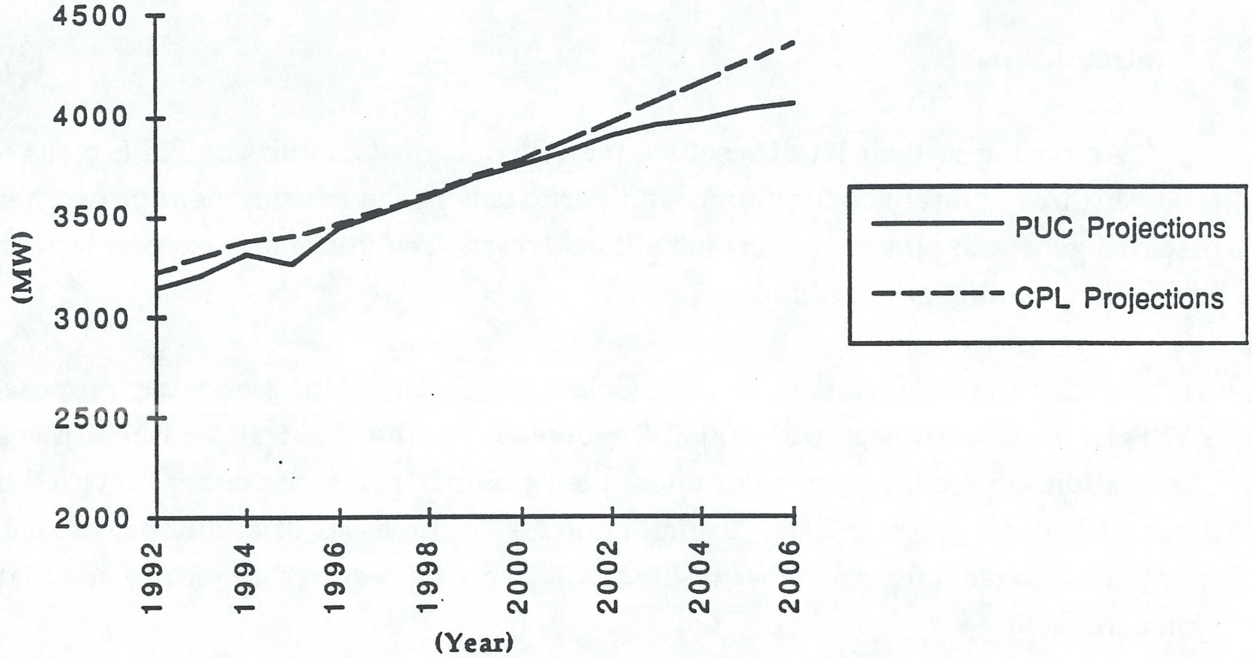


Figure 5.2
Comparison of PUC Staff and Utility-Developed Sales Projections: Central Power and Light Company

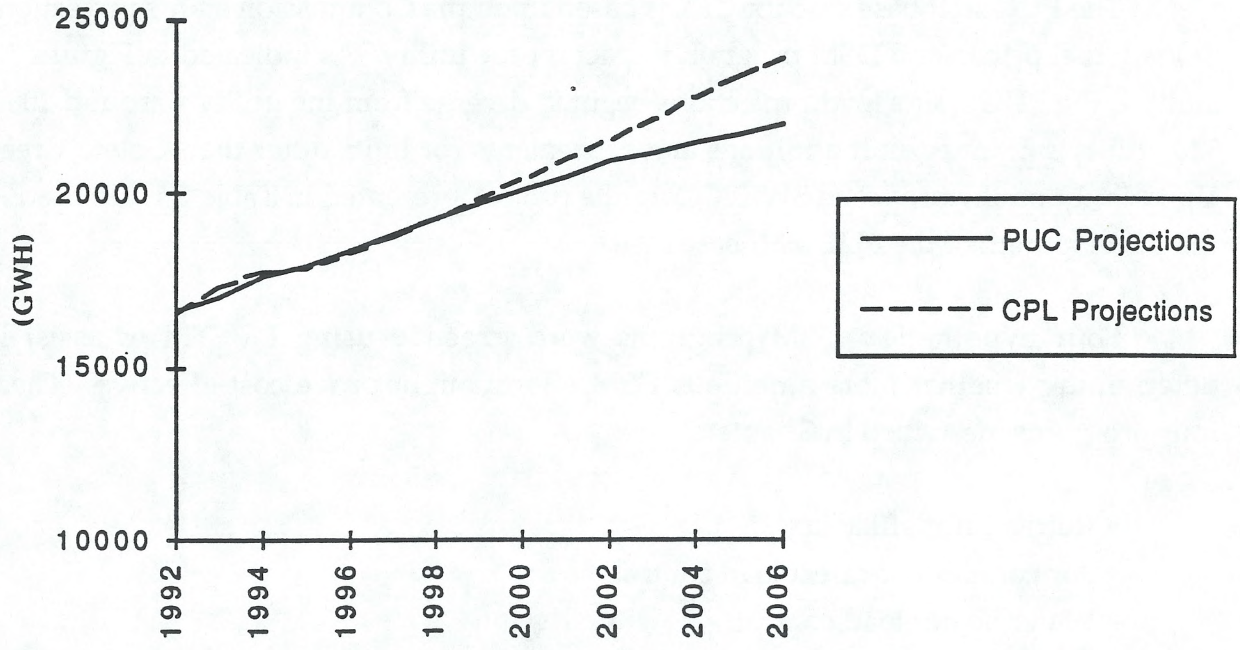


Table 5.1
Central Power and Light Company: Utility Planned Unit Additions and Retirements under PUC Staff Base Case Assumptions

Commercial Operation Date	Plant Name	Unit #	Regulatory Status	Net MW Owned	Primary Fuel	$/kW Including AFUDC
1992	Oklaunion	1	-	2	SUB	-
2001	Repower Laredo	2	-	89	NG	-
	Laredo	1	-	(36)	NG	-
2002	Repower JL Bates	1	-	163	NG	-
2004	Repower LC Hill	1	-	173	NG	-
	Victoria	4	-	(45)	NG	-
	Lon C Hill	3	-	(158)	NG	-
2005	JL Bates	2	-	(111)	NG	-
	La Palma	7	-	(47)	NG	-
	TOTAL			596		

Key: NG=Natural Gas SUB=Subbituminous Coal

Each program was assumed to have value as a means of conserving energy from 1992 to 2000. From 2000 to 2006, the programs (with the exception of the valley-filling contract lighting program) were assumed to have capacity value as well as energy value. Capacity value was estimated based on a levelized payment stream calculated from the utility's Avoided Cost filing.

At the request of the Commission staff, a second set of benefit-cost calculations was performed using a new combined cycle natural gas-fired generating unit as the avoidable unit. It was felt that a more aggressive DSM effort might prompt the deferral or cancellation of a larger capacity addition than would be represented by the repowering of a small unit. Cost data pertaining to the hypothetical combined cycle unit were obtained from HL&P's resource plan. Use of the higher avoided capacity costs associated with the hypothetical combined cycle addition tends to raise the resulting benefit-cost ratios.

The results of this benefit-cost analysis are presented in Table 5.2. Only the Refrigerator Efficiency program passed the benefit-cost from the utility and total resource cost perspectives. Consequently, this program was included in the PUC staff base case. Projected program impacts are reported in Table 5.3. The unfavorable benefit-cost ratios for the Air Conditioner and Water Heater Load Control programs are attributable to the utility's relatively low near-term value of capacity.

Table 5.2
Central Power and Light Company
Benefit-Cost Ratios for Hypothetical DSM Programs
under Utility's Proposed Avoided Cost

DSM Program	Utility Test	Total Resource Test
Using utility's calculation of Avoided Capacity Cost:		
Refrigerator Efficiency	1.12	1.46
Air Conditioner Direct Load Control	0.16	0.25
Water Heater Load Control	0.12	0.13
Contract Lighting	0.01	0.00
Using a combined cycle natural gas-fired plant as the Avoidable Unit:		
Refrigerator Efficiency	1.25	1.62
Air Conditioner Direct Load Control	0.28	0.45
Water Heater Load Control	0.21	0.23
Contract Lighting	0.01	0.00

Table 5.3
Central Power and Light
Impact of Hypothetical DSM Programs
That Pass the Total Resource Cost Test

Year	Impact of Refrigerator Efficiency Program MW	MWH
1992	0	(2,000)
1993	0	(4,000)
1994	(1)	(6,000)
1995	(1)	(8,000)
1996	(1)	(10,000)
1997	(1)	(12,000)
1998	(2)	(14,000)
1999	(2)	(16,000)
2000	(2)	(17,000)
2001	(2)	(19,000)
2002	(3)	(21,000)
2003	(3)	(23,000)
2004	(3)	(25,000)
2005	(3)	(27,000)
2006	(4)	(29,000)

Given the lower peak demand growth projected by the Commission staff for the later years of the forecast horizon, projected reserve margins are higher than utility projections for the 2000 to 2006 period. Projected reserve margins under PUC staff base case projections are presented in Table 5.4. Fuel cost and fuel usage forecasts under PUC staff base case assumptions appear in Tables 5.5 and 5.6.

Table 5.4
Reserve Margin Calculation under PUC Staff Base Case Assumptions: Central Power and Light Company

Year	PUC Staff Adjusted System Peak (MW)	Additional DSM (MW)	Installed Capacity (MW)	Firm Purchases (MW)	Additional Firm Purchases (MW)	Reserve Margin (%)
1992	3,150	0	4,402	0	0	39.8
1993	3,210	0	4,402	0	0	37.1
1994	3,321	1	4,402	0	0	32.6
1995	3,265	1	4,402	0	0	34.8
1996	3,447	1	4,402	0	0	27.7
1997	3,529	1	4,402	0	0	24.7
1998	3,609	2	4,402	0	0	22.0
1999	3,691	2	4,402	0	0	19.3
2000	3,762	2	4,402	14	0	17.4
2001	3,828	2	4,335	39	26	15.0
2002	3,899	3	4,258	0	222	15.0
2003	3,954	3	4,381	0	163	15.0
2004	3,986	3	4,370	26	184	15.0
2005	4,031	3	4,430	0	202	15.0
2006	4,066	4	4,430	30	211	15.0

Table 5.5
Central Power and Light Company Total Fuel Costs:
Comparison of Utility and PUC Staff Base Case Projections
(Thousands of Dollars)

Year	Utility Projection	PUC Staff Base Case Projection
1992	296,264	295,844
1993	327,720	338,922
1994	362,872	379,785
1995	370,383	398,526
1996	466,744	424,831
1997	470,353	457,878
1998	524,364	492,823
1999	592,604	537,652
2000	669,773	583,526
2001	761,051	633,339
2002	822,202	694,969
2003	884,118	754,556
2004	962,515	811,400
2005	1,032,208	775,152
2006	1,113,925	847,854

NOTE: Source of utility projection: CSW PROMOD run dated 2/29/92.

Table 5.6
Central Power and Light Company: Projected Fuel Consumption under PUC Staff Base Case Assumptions
(Thousands of MMBtu)

Year	Natural Gas	Coal	Nuclear
1992	147,164	17,271	41,846
1993	153,894	17,269	37,650
1994	158,780	19,653	38,655
1995	157,834	20,082	39,535
1996	160,620	20,719	40,001
1997	168,108	18,041	39,938
1998	170,458	21,255	39,938
1999	168,178	20,737	39,938
2000	182,186	20,054	39,938
2001	185,850	18,200	39,938
2002	188,567	21,350	39,938
2003	191,503	22,972	39,938
2004	195,447	22,518	39,938
2005	196,263	20,482	39,938
2006	201,372	23,752	39,938

Under the PUC staff base case assumptions, CPL's average system rates are projected to increase at a low 2.2 percent average annual rate from 1992 to 2006. The utility's fuel costs are expected to increase at a greater rate than costs recovered through base rates. Projected system-wide rates under the PUC staff base case assumptions are presented in Table 5.7.

Table 5.7
Projected System-Wide Rates under PUC Staff Base Case Assumptions:
Central Power and Light Company
(Dollars per kWh)

Year	Avg. Base Rate	Fuel Factor	Total Avg. Rate
1992	.055	.017	.072
1993	.053	.019	.072
1994	.053	.021	.073
1995	.052	.021	.073
1996	.051	.022	.073
1997	.053	.023	.076
1998	.053	.024	.078
1999	.054	.026	.080
2000	.056	.028	.084
2001	.055	.030	.085
2002	.056	.032	.088
2003	.057	.034	.091
2004	.057	.035	.092
2005	.060	.036	.096
2006	.060	.039	.099

5.3 Analysis of Existing and Utility-Planned DSM Programs

In the PUC base case scenario, existing DSM programs were explicitly modeled in LMSTM, in order to develop an accurate system load curve and determine peak, energy and economic impacts of individual programs. Proper matching of program impacts and the costs incurred in obtaining those impacts are necessary for benefit/cost analysis. Aggregate loadshapes are used for programs that consist of many different end uses, since cost data are available only at the program level.

CPL apparently does not have a set of usable loadshapes for its current programs. Fortunately, each CPL program could be matched to an almost identical program at HL&P, and it was assumed that a particular program would have a similar impact in both service areas. Therefore, CPL's loadshapes were generated by scaling the appropriate HL&P 1992 DSManager loadshapes to CPL's expected load and energy impacts for each program. Expected energy and coincident peak demand impacts for each program are enumerated in Table IV.C.13 of each utility company's December 31, 1991, Energy Efficiency Plan. Most of CPL's demand and energy impact assumptions were accepted as reasonable by PUC staff. For various reasons, impacts of some programs were not accepted, and these programs were not modeled.

Cost figures were provided only for 1992 and 1993, and classifying costs as fixed or variable was sometimes difficult or impossible. Thus, development of accurate program cost estimates was hampered because of a lack of data.

Benefit/Cost Analysis

All modeled programs were subjected to the California Standard Total Resource Cost and the Utility Cost tests in order to gauge their cost-effectiveness. The benefit/cost modeling performed by CES differed substantially from that of the utility. While CPL used DSManager, a static model, CES used the Load Management Strategy Testing Model, a dynamic planning model. The model employed by CES generates rate and marginal cost data that must be directly input into a model such as DSManager. Some program and participant cost inputs were also not made explicit and were estimated from the data that were available.

The Residential A/C Checkup, Commercial High-Efficiency Chiller, and Residential Good Cents programs seem to be cost effective according to both tests, while both tests indicate that the Commercial Efficient Electrotechnologies and Commercial Thermal Energy Storage programs are uneconomical (see Table 5.8).

The Electrotechnologies program is probably not cost effective because it increases energy consumption and peak load by encouraging electrification, and thus increases costs to the utility and society. The Thermal Storage program does not reduce energy consumption, and the peak reduction value is reduced by the fact that CPL will not need any new capacity for several years; the high level of incentives paid to participants makes this program look uneconomical. The utility's estimates of its avoided capacity costs were adopted in each of these calculations.

Table 5.8
Benefit-Cost Ratios for Existing DSM Programs
Central Power and Light Company

DSM Program	Utility Cost	Total Resource Cost
Residential A/C Checkup	4.14	4.14
Residential Centsable	1.31	0.90
Commercial High-Efficiency Chiller	1.26	3.03
Commercial HVAC and Lighting Audits	8.29	0.87
Commercial Unitary HVAC Program	5.00	0.40
Commercial Efficient Electrotechnologies	0.58	0.32
Residential Good Cents Program	1.75	1.26
Residential High-Efficiency A/C Incentive	1.40	0.75
Commercial Thermal Energy Storage	0.66	0.66

Residential Centsable, Residential High-Efficiency A/C Incentive, Commercial HVAC and Lighting Audits, and Commercial Unitary HVAC seem to be cost effective from the utility's perspective, but not in terms of total resource costs.

CHAPTER 6

WEST TEXAS UTILITIES COMPANY

6.1 Introduction

Under the PUC staff base case scenario, Coleto Creek Unit No. 2 and the proposed SWEPCO lignite project (to be jointly owned by the Central and Southwest Operating Companies under the utility's resource plan) are either cancelled or deferred beyond the year 2006. Additional purchases of firm capacity or greater reliance upon DSM resources may be necessary to ensure system reliability.

Three of the utility's existing DSM programs—the Residential Energy Savings Plan, the Question Residential Audit Program, and the Industrial Audit Program—have been evaluated in light of the PUC staff base case assumptions. The benefit-cost test results obtained were similar to the utility's calculations.

In addition to the PUC staff base case, a number of alternative planning scenarios have been analyzed to determine whether changes to the utility's current resource plan might result in lower costs without jeopardizing reliability. One hypothetical DSM program appears to be marginally economical, while three other hypothetical programs appear to provide limited value from a total resource perspective.

6.2 PUC Staff Base Case

The PUC staff base case reflects the Commission staff's load forecast and fuels price projections for WTU. The Commission staff's demand projections are similar to the utility's as indicated in Figures 6.1 and 6.2.

Planned capacity additions and retirements are identified in Table 6.1. The PUC staff base case scenario largely retains the utility's capacity expansion plan, aside from the deferral of the SWEPCO lignite and Coleto Creek Unit No. 2 projects.

The lower total fuel costs projected under PUC staff base case assumptions largely reflect the lower unit fuel prices (particularly for natural gas) forecast by the Commission staff. A 6 percent average annual increase in the utility's total fuel bill is

Figure 6.1
Comparison of PUC Staff and Utility-Adjusted Peak Demand Projections: West Texas Utilities Company

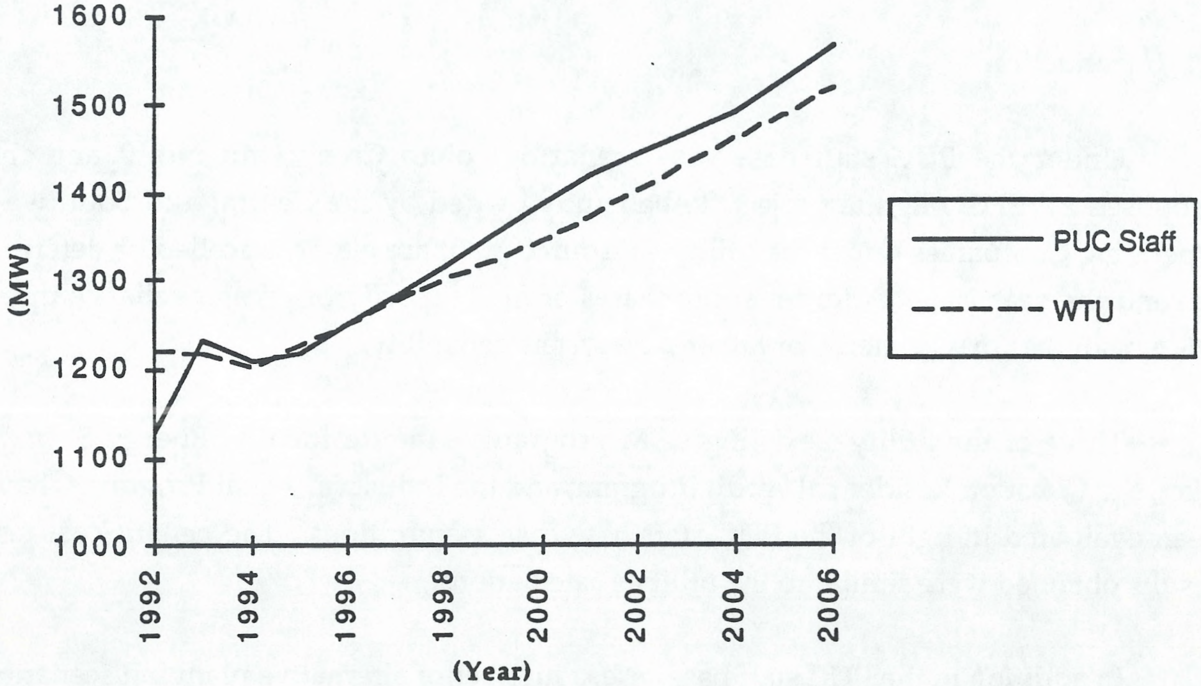


Figure 6.2
Comparison of PUC Staff and Utility-Adjusted Sales Projections: West Texas Utilities Company

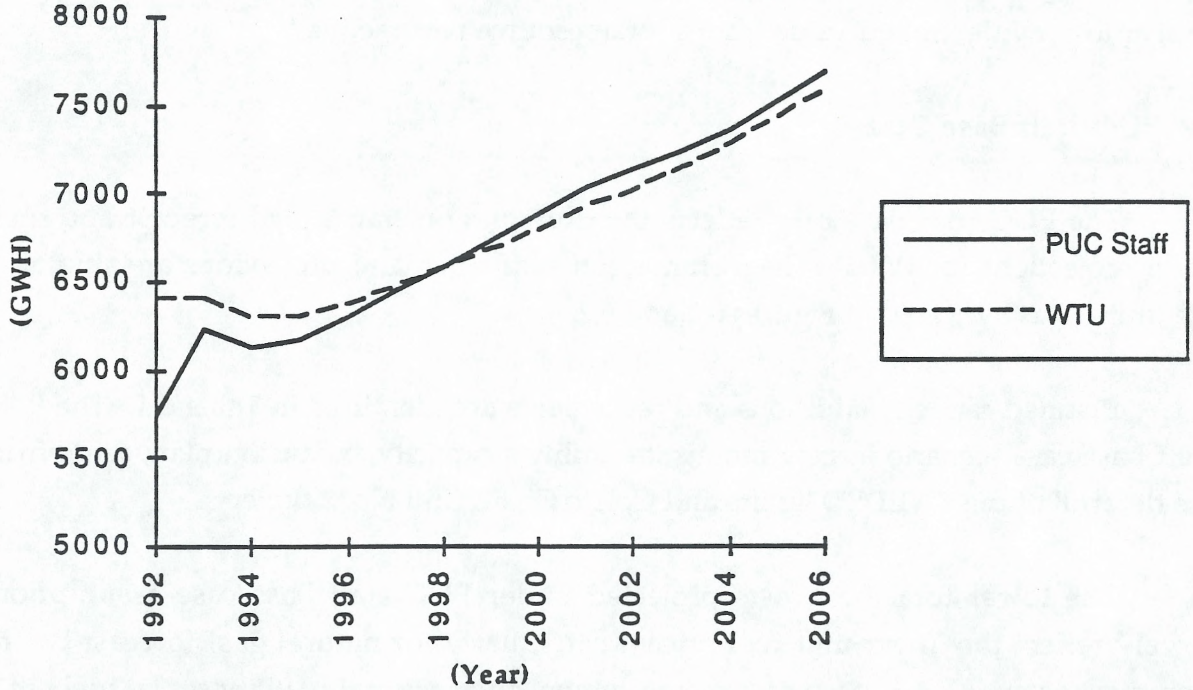


Table 6.1
West Texas Utilities Company
Planned Capacity Additions and Retirements

Commercial Operation Date	Plant Name	Unit #	Regulatory Status	Net MW Owned	Primary Fuel	$/kW including AFUDC
1992	OKLAUNION (rerating)	1	–	11	SUB	–
	UPGRADE	–	–	4	NG	–
1998	ABILENE	4	–	(18)	NG	–
	FORT STOCKTON	2	–	(5)	NG	–
	LAKE PAULINE	1	–	(19)	NG	–
2000	WTU CC	1	–	114	NG	–
	REPOWER RIO PECOS	5	–	122	NG	–
	RIO PECOS	4,5	–	(41)	NG	–
2002	WTU CC	2	–	114	NG	–
	LAKE PAULINE	2	–	(27)	NG	–
2003	PAINT CREEK	1	–	(33)	NG	–
2005	PAINT CREEK	2,3	–	(87)	NG	–
2006	WTU CC	3	–	114	NG	–
	TOTAL			471		

KEY: NG=Natural Gas SUB=Subbituminous

projected for the period 1992 to 2006 under PUC staff base case assumptions, as indicated in Table 6.2 and Figure 6.3. Projected fuel requirements are reported in Table 6.3.

Four hypothetical DSM programs were screened using LMSTM:

- A refrigerator efficiency program;
- An air conditioner direct load control program;
- A water heater load control program; and
- A contract lighting program.

It was assumed that each program would begin in 1992 and would continue through 2006.

Table 6.2
Total Fuel Costs: Comparison of Utility and PUCStaff Base Case Projections
West Texas Utilities Company

Year	Utility Projection (Thousands of $)	PUC Staff Base Case Projection (Thousands of $)
1992	N/A	103,549
1993	N/A	120,325
1994	143,797	128,632
1995	152,513	137,040
1996	166,913	144,055
1997	185,560	152,682
1998	205,359	171,555
1999	225,726	176,835
2000	248,640	192,183
2001	252,193	204,672
2002	268,488	223,538
2003	285,885	232,257
2004	311,740	235,250
2005	337,529	215,273
2006	346,448	248,523

NOTE: Source of utility projection: CSW PROMOD run dated 5/19/92.

Figure 6.3
Total Fuel Costs: Comparison of Utility Projections with PUC Staff Base Case Projections

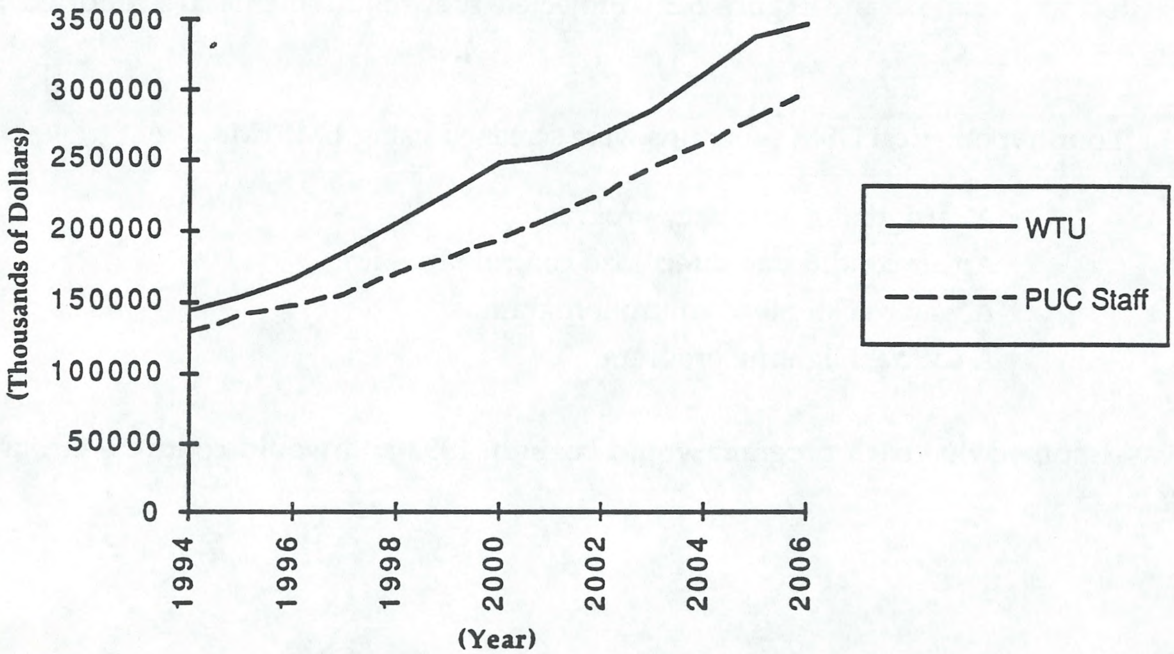


Table 6.3
West Texas Utilities Company: Projected Fuel Consumption under PUC Staff Base Case Assumptions (Thousand MMBtu)

Year	Natural Gas	Coal
1992	37,163	25,661
1993	52,125	17,028
1994	41,581	27,221
1995	40,533	28,594
1996	40,993	28,762
1997	42,640	28,341
1998	49,966	24,027
1999	45,910	28,871
2000	47,634	28,687
2001	47,009	28,588
2002	49,612	28,552
2003	50,340	23,947
2004	44,018	28,444
2005	35,625	27,864
2006	39,953	28,916

The benefit-cost ratios for each DSM program are presented in Table 6.4. The Refrigerator Efficiency program described in Chapter 2 appears to be marginally economical from utility and total resource perspectives. The Water Heater Control program proved economical from the total resource perspective and, consequently, has been included in the PUC staff base case scenario. Program costs exceed expected benefits for the hypothetical valley filling program from either perspective.

In performing the benefit-cost analysis, it was assumed that each DSM program would have limited capacity value until the year 2000, the year of WTU's next planned generating capacity addition. However, upon review of the reserve margin calculations presented in Table 6.5, one might conclude that a DSM program might have capacity value much earlier. Including possible capacity value in earlier years for DSM programs would increase the benefit-cost ratios presented here.

Table 6.4
Benefit-Cost Ratios for Hypothetical DSM Programs under Utility's Proposed Avoided Cost: West Texas Utilities Company

DSM Program	Utility Test	Total Resource Test
Using Utility's Proposed Avoided Cost:		
Refrigerator Efficiency	0.76	0.89
Air Conditioner Direct Load Control	0.15	0.17
Water Heater Load Control	0.19	0.72
Contract Lighting	0.03	0.03
Using a Combined Cycle Unit as the Avoidable Unit:		
Refrigerator Efficiency	0.84	0.98
Air Conditioner Direct Load Control	0.27	0.32
Water Heater Load Control	0.36	1.32
Contract Lighting	0.03	0.03

For WTU, electricity prices are expected to increase at rates below the anticipated rate of inflation through the end of the forecast horizon. Total system-wide average rates are forecast to increase at a 3.7 percent average annual rate. The utility's fuel-related costs are projected to increase at a greater rate than costs recovered through base rates. Projected system-wide rates under the PUC staff base case scenario are presented in Table 6.6.

6.3 Analysis of Existing DSM Programs

Three existing DSM programs were explicitly modeled in LMSTM:

- The Residential Energy Savings Plan;
- The Quest Program; and
- The Industrial Audit Program.

The Residential Energy Savings Plan is designed to encourage the installation of high energy efficiency electric heating and cooling equipment and promote improvement in the thermal envelope characteristics of houses. While summer electric peak demand is projected to be significantly reduced through this program (a 4 MW peak demand reduction is projected by the year 2000), winter peak demand is expected

Table 6.5
Reserve Margin Calculation under PUC Staff Base Case Assumptions: West Texas Utilities Company

Year	PUC Staff Adjusted System Peak (MW)	Additional DSM (MW)	Installed Capacity Firm Purchases (MW)	Utility Planned Purchases (MW)	Additional Firm (MW)	Firm Sales (MW)	Net Capacity (MW)	Reserves Margin (%)
1992	1,221	0	1,384	5	16	0	1,405	15
1993	1,218	0	1,384	2	15	0	1,401	15
1994	1,204	0	1,384	0	1	0	1,385	15
1995	1,227	0	1,384	12	15	0	1,411	15
1996	1,252	0	1,384	42	14	0	1,440	15
1997	1,276	0	1,384	68	15	0	1,467	15
1998	1,300	1	1,342	139	13	0	1,494	15
1999	1,323	1	1,342	164	15	0	1,521	15
2000	1,346	1	1,539	0	10	2	1,547	15
2001	1,373	1	1,539	27	12	0	1,578	15
2002	1,402	1	1,626	0	0	0	1,626	15
2003	1,432	1	1,593	0	53	0	1,646	15
2004	1,461	1	1,593	0	88	2	1,683	15
2005	1,490	1	1,506	0	206	0	1,712	15
2006	1,520	1	1,620	0	145	18	1,783	15

to increase by a similar amount, as a result of heat pump promotion. This program has been in operation since 1983. All residential customers are eligible to participate.

Each of the program options of the Residential Energy Savings Plan has been modeled separately. These program options for single family homes are:

Base Case 1: Option 1 - Central AC with 11 SEER with gas furnace
Option 2 - Central AC with 11 SEER with gas back-up
Option 3 - Central heat pump with 11 SEER with resistance heat backup
Base Case 2: Option 1 - Central heat pump with 10 SEER
Base Case 3: Option 1 - Room air conditioner with resistance heat
Base Case 4: Option 1 - Central heat pump with heat recovery
Base Case 5: Option 1 - Solar assisted electric water heater

Table 6.6
Projected System-Wide Rates under PUC Staff Base Case Assumptions:
West Texas Utilities Company
(Dollars per kWh)

Year	Average Base Rate	Fuel Factor	Total Average Rate
1992	.031	.018	.048
1993	.030	.019	.049
1994	.031	.020	.051
1995	.032	.022	.054
1996	.031	.023	.054
1997	.031	.023	.055
1998	.032	.026	.058
1999	.032	.026	.058
2000	.035	.027	.062
2001	.037	.029	.066
2002	.038	.031	.069
2003	.040	.033	.073
2004	.042	.035	.077
2005	.045	.037	.082
2006	.049	.038	.087

For each of these program options, participant load curve data were obtained from the utility. Cost and participation data were collected from the utility's Energy Efficiency Plan.

The Quick Energy Savings Test (Quest), a residential sector audit program, and the utility's Industrial Audit Program were also explicitly modeled using load data, projected participation rates, and cost data provided by the utility and reviewed by the Commission staff. The DSM program benefit-cost ratios calculated through LMSTM using PUC staff base case assumptions are presented in Table 6.7.[8] The results for the Residential Energy Savings Plan obtained through LMSTM were similar to the ratios calculated by the utility. Program costs exceed benefits derived from this program from the utility and total resource perspectives.

[8] The ratios calculated by LMSTM were adjusted through a separate spreadsheet to include benefits of capacity requirements reduction that could not be easily represented in LMSTM.

Table 6.7
Benefit-Cost Ratios for Existing DSM Programs:
West Texas Utilities Company

DSM Program	Utility Test	Total Resource Test
Residential Energy Savings Plan	0.17	0.12
Quest Program	14.17	21.01
Industrial Audit Program	142.75	21.01

For the Quest residential audit program, the benefit-cost ratios calculated were somewhat lower than the utility's estimates. LMSTM runs indicate that this program is cost-effective from either the utility or total resources perspectives. The Industrial Audit Program appears to be highly cost-effective from utility and total resource perspectives under either the PUC staff base case assumptions or the utility's calculations.

CHAPTER 7

SOUTHWESTERN ELECTRIC POWER COMPANY

7.1 Introduction

Southwestern Electric Power Company (SWEPCO) currently has one of the state's highest reserve margins, and surplus capacity is expected to persist until beyond the year 2000. Consequently, the utility anticipates no need to increase generating capacity until 2001.

The demand forecast developed by the PUC staff for SWEPCO is largely consistent with the load projections developed by the utility. Under the PUC staff base case scenario, the utility-proposed SWEPCO lignite project and Coleto Creek Unit No. 2 are deferred beyond the end of the forecast horizon.

Three hypothetical DSM programs were screened using LMSTM:

- A refrigerator efficiency program;
- An air conditioner direct load control program; and
- A water heater load control program.

The Refrigerator Efficiency program was found to satisfy the benefit-cost tests and has been included in the PUC staff base case. Additional purchases of power from cogenerators or other utilities have also been reflected in the PUC staff base case to satisfy the Commission staff's reserve margin target.

7.2 PUC Staff Base Case

Development of the PUC staff base case for SWEPCO relied upon the PUC staff's independent demand and fuels price projections. Figures 7.1 and 7.2 compare the staff's load projections to those of the utility. The forecasts made by the staff for natural gas prices tend to be much lower than the utility's. The planned capacity additions and retirements are reported in Table. 7.1.

Figure 7.1
Comparison of PUC Staff and Utility Adjusted Peak Demand Projections: SWEPCO

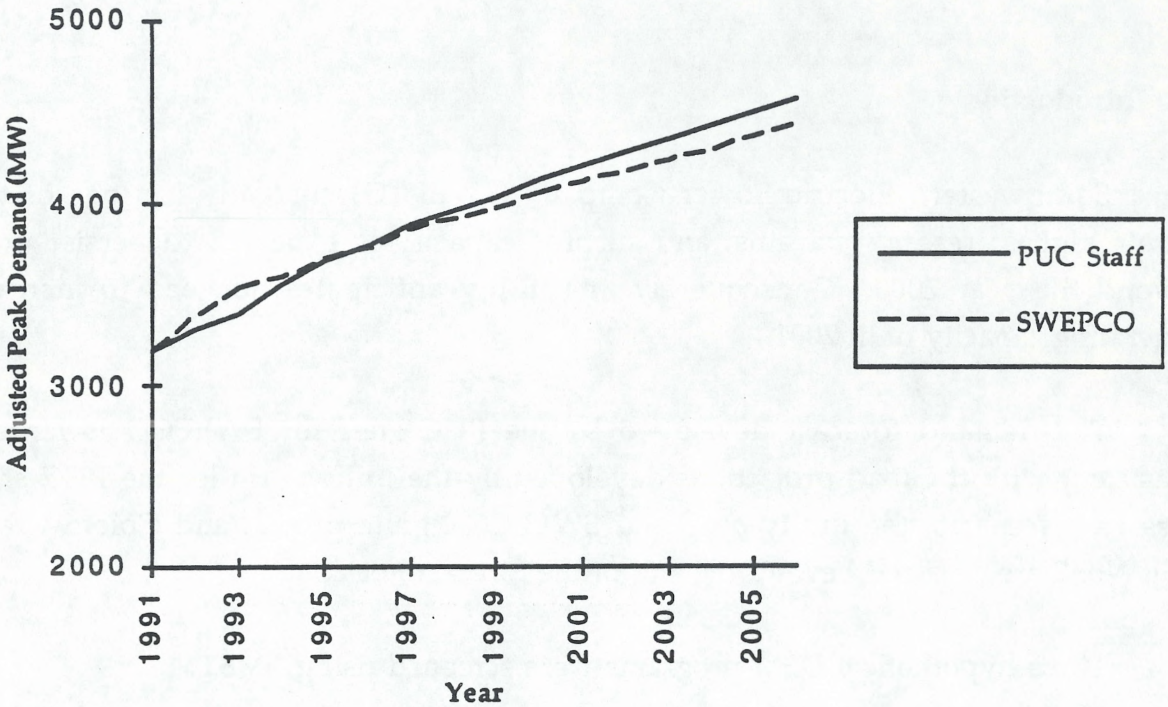
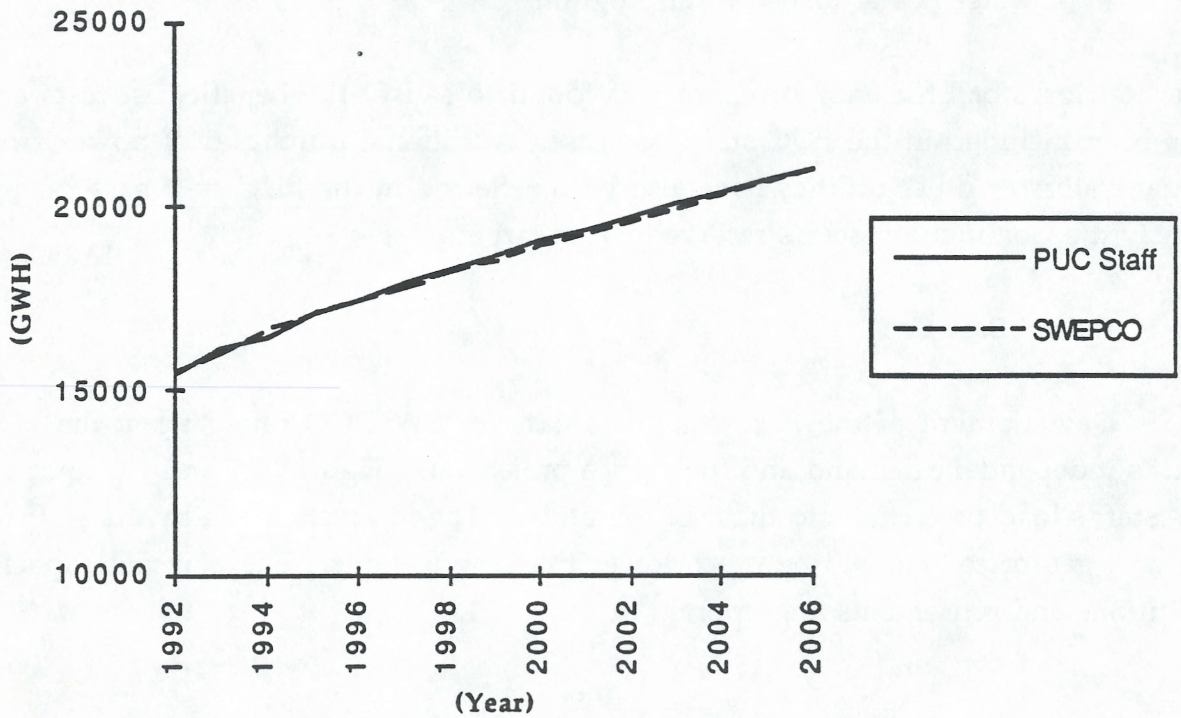


Figure 7.2
Comparison of PUC Staff and Utility Adjusted Sales Projections: SWEPCØ



For the SWEPCO system, existing DSM programs were not explicitly modeled. The PUC staff determined that current programs at SWEPCO do not have a sufficiently significant impact on peak demand nor sales to merit inclusion of those programs.

Three hypothetical DSM programs were analyzed using LMSTM:

- A refrigerator efficiency program,
- An air conditioner direct load control program; and
- A water heater load control program.

It was assumed that each program would begin in 1992 and would continue through 2006. Because the SWEPCO system has ample generating capacity over the next ten years, the programs do not have any capacity value until around 2001.

Benefit-cost ratios for the three hypothetical DSM programs are reported in Table 7.2. Two sets of calculations are presented. The first set uses the utility's proposed "avoidable unit," described in the utility's December 1991 Avoided Cost filing with the Texas Commission, as the basis for determining the benefits of avoided capacity. The utility's proposed avoided cost is based upon repowering an existing unit on the SWEPCO system.

At the request of the Commission staff, a second set of calculations was performed using a new combined cycle natural gas-fired generating unit as the avoidable unit. It was felt that a more aggressive DSM effort might prompt the deferral or cancellation of a larger capacity addition than would be requested by the repowering of a small unit. Cost data pertaining to the hypothetical combined cycle unit were obtained from HL&P's resource plan. Use of the higher avoided capacity costs associated with the hypothetical combined cycle addition tends to raise the resulting benefit-cost ratios.

Of the three programs screened, only the Refrigerator Efficiency Program passed the benefit-cost tests when a combined cycle unit was used as the basis for avoided capacity costs. The PUC staff base case resource plan includes this hypothetical program as "Additional DSM."

Table 7.1
Southwestern Electric Power Company
Planned Capacity Additions and Retirements

Commercial Operation Date	Plant Name	Unit No.	Regulatory Status	Net MW Owned	Primary Fuel	$/kW Including AFUD
2001	Repower Wilkes	2	—	87	NG	---
	Lieberman (1)	1,2	—	(56)	NG	---
2002	Repower Wilkes	3	—	87	NG	---
	Knox Lee (1)	2,3	—	(74)	NG	---
2003	Lone Star (1)	1	—	(50)	NG	---
	Unspecified	1	—	130	NG	---
2004	Unspecified	1	—	130	NG	---
2005	Unspecified	1	---	80	NG	---
2006	Unspecified	1	---	61	NG	---

KEY: NG=Natural Gas

Table 7.2
Benefit-Cost Ratios for Hypothetical DSM Programs:
Southwestern Electric Power Company

DSM Program	Utility Test	Total Resources Test
Using the utility's Avoided Cost calculation:		
Refrigerator Efficiency	0.99	0.99
AC Direct Load Control	0.00	0.01
Water Heater Load Control	0.00	0.00
Using a combined cycle natural gas-fired unit as the Avoidable Unit:		
Refrigerator Efficiency	1.12	1.12
AC Direct Load Control	0.00	0.01
Water Heater Load Control	0.00	0.00

The reserve margin calculation presented in Table 7.3 reflects this additional DSM, as well as additional firm purchases from cogenerators or other utilities necessary to ensure that the 15 percent reserve margin target established by the PUC staff for this utility is satisfied. Additional firm purchased power is necessary in the years 2000 and 2002 through 2006 under the PUC staff base case assumptions. The assumptions used to determine an appropriate cost of this additional purchased power is described in Chapter 2. While it is assumed here that this projected capacity deficiency will be satisfied with firm cogeneration, more extensive screening or a solicitation for resources may reveal other cost-effective resource options.

Table 7.3
Reserve Margin Calculation under PUC Staff Base Case Assumptions: Southwestern Electric Power Company

Year	PUC Staff Adjusted System Peak (MW)	Additional DSM (MW)	Installed Capacity (MW)	Utility-Planned Purchases (MW)	Additional Firm Purchases (MW)	Firm Sales (MW)	Net Capacity (MW)	Reserve Margin (%)
1991	3200	0	4557	153	0	50	4660	46
1992	3309	0	4557	153	0	50	4660	41
1993	3401	0	4557	153	0	50	4660	37
1994	3550	0	4557	153	0	67	4643	31
1995	3684	1	4557	153	0	82	4628	26
1996	3764	1	4557	153	0	105	4605	22
1997	3881	1	4557	153	0	77	4633	19
1998	3953	1	4557	153	0	54	4656	18
1999	4030	1	4557	266	0	50	4773	18
2000	4125	1	4557	189	47	50	4743	15
2001	4196	2	4588	304	0	50	4842	15
2002	4271	2	4601	153	205	50	4909	15
2003	4347	2	4681	153	218	53	4999	15
2004	4417	2	4811	153	208	95	5077	15
2005	4488	2	4891	153	165	50	5159	15
2006	4558	2	4952	157	180	50	5239	15

Simulation results from LMSTM for the SWEPCO system under base case assumptions are provided in Tables 7.4 and 7.5 and Figures 7.3 and 7.4 The PUC staff's lower fuel price projections result in a total fuel cost projection for the PUC staff base case which is significantly lower than the utility's projection. Coal and lignite are expected to continue to be the dominant fuels in SWEPCO's generation mix in the foreseeable future.

Projections of average system-wide electricity rates under the PUC staff base case assumptions are reported in Table 7.6 and Figure 7.5. The average system rate is expected to increase from its present level of five cents per kWh to seven cents by 2006.

Table 7.4
Total Fuel Costs Comparison of Utility Projection with PUC Staff Base Case Projection: Southwestern Electric Power Company
(Thousands of Dollars)

Year	Utility Projection	PUC Staff Base Case Projection
1992	334, 136	305,090
1993	371, 985	322,203
1994	395, 529	349,010
1995	410, 886	426,549
1996	426, 638	392,466
1997	467, 603	419,661
1998	514, 582	442,072
1999	562, 723	505,761
2000	614, 869	578,987
2001	662, 222	531,905
2002	699, 640	571,754
2003	715, 509	561,520
2004	783, 739	631,304
2005	825, 380	736,579
2006	851, 776	761,323

Source of utility projection: CSW PROMOD run dated 5/29/92.

Table 7.5
Southwestern Electric Power Company:
Projected Fuel Consumption under PUC Staff Base Case Assumptions
(Thousands of MMBtu)

Year	Natural Gas	Coal	Lignite
1992	16,086	100,890	75,752
1993	14,595	105,340	77,902
1994	12,956	114,356	77,715
1995	43,568	109,481	57,292
1996	14,269	122,473	80,370
1997	18,193	123,938	80,741
1998	18,779	127,317	80,747
1999	37,834	112,425	79,046
2000	39,729	137,736	57,682
2001	25,866	131,494	81,215
2002	29,182	131,246	81,417
2003	23,258	131,895	81,433
2004	41,121	113,397	79,297
2005	45,020	139,107	57,834
2006	30,319	136,466	81,649

Figure 7.3
Total Fuel Costs Comparison of Utility & PUC Base Case Projections: Southwestern Electric Power Co.

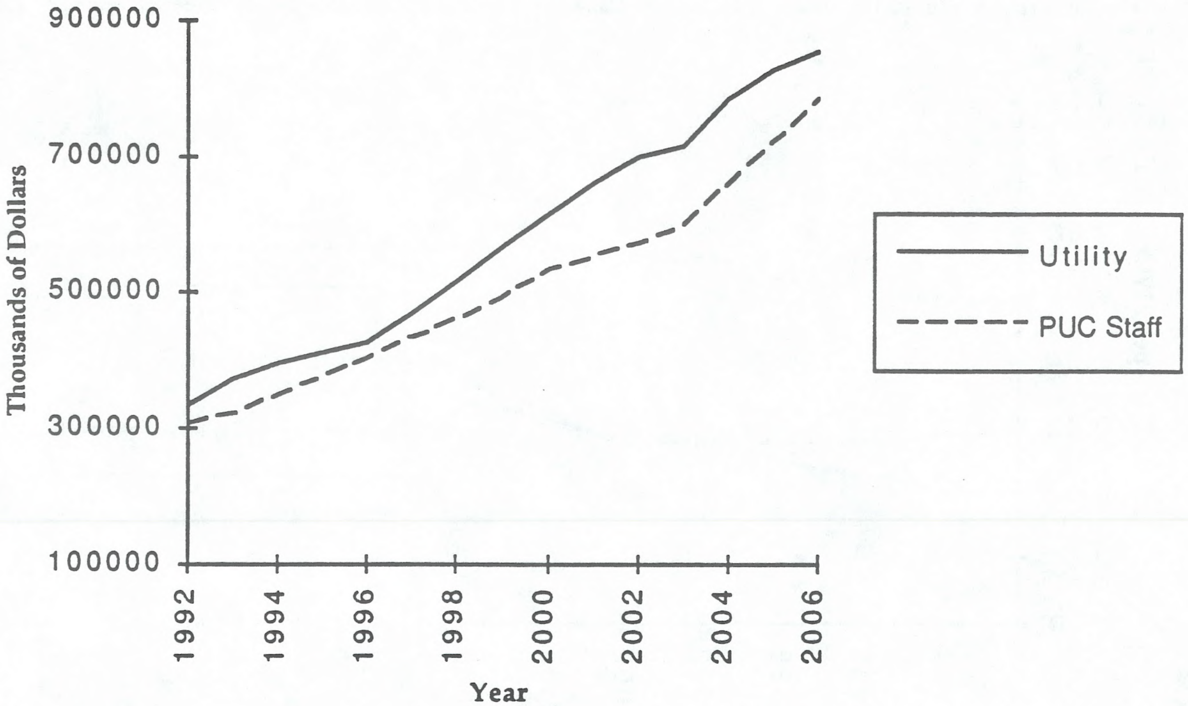


Figure 7.4
Projected Fuel Consumption under PUC Base Case Assumptions: Southwestern Electric Power Co.

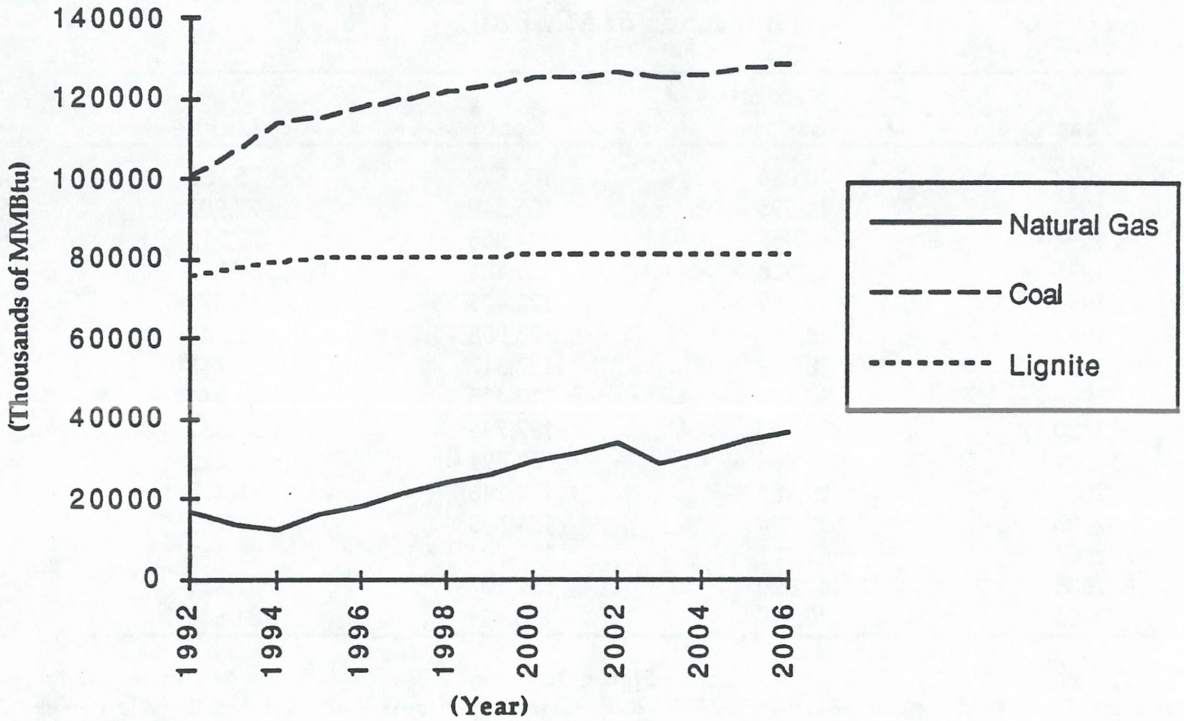


Figure 7.5
Projected System-Wide Rates under PUC Base Case Assumptions: Southwestern Electric Power Co.

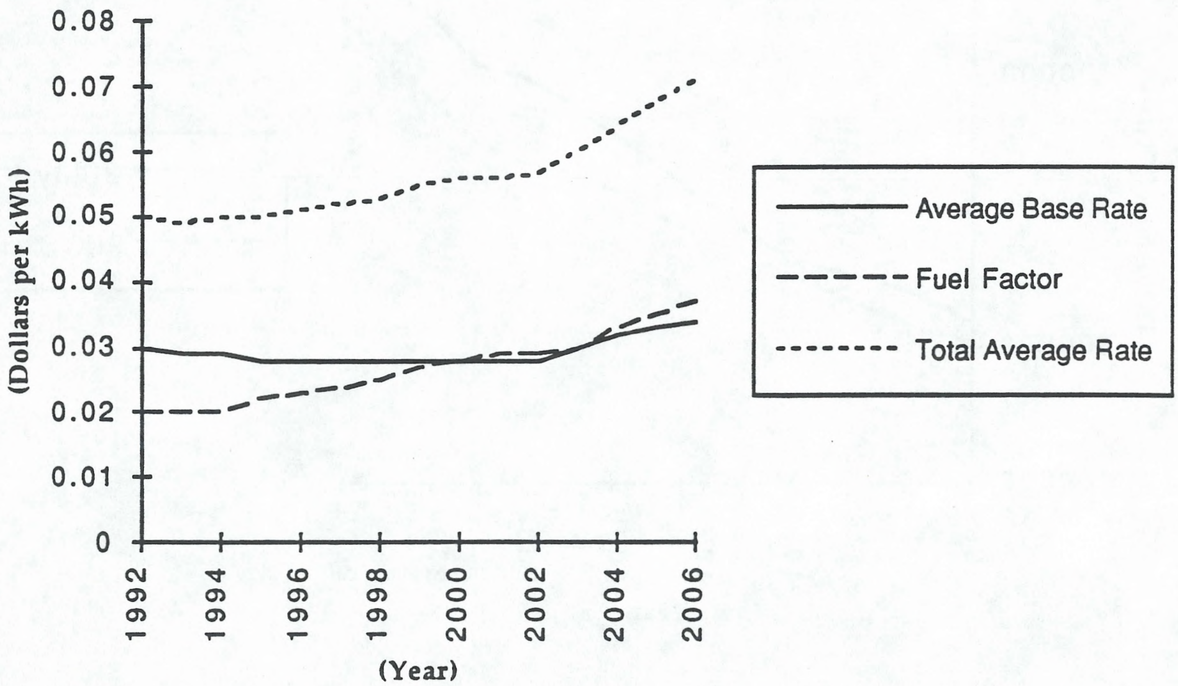


Table 7.6
Projected System-Wide Rates under PUC Staff Base Case Assumptions: Southwestern Electric Power Company (Dollars per kWh)

Year	Average Base Rate	Fuel Factor	Total Average Rate
1992	0.030	0.020	0.050
1993	0.029	0.020	0.049
1994	0.029	0.021	0.050
1995	0.029	0.025	0.054
1996	0.028	0.023	0.051
1997	0.028	0.023	0.051
1998	0.028	0.024	0.052
1999	0.028	0.027	0.055
2000	0.028	0.030	0.058
2001	0.027	0.028	0.055
2002	0.028	0.029	0.057
2003	0.029	0.030	0.059
2004	0.029	0.033	0.062
2005	0.029	0.037	0.066
2006	0.029	0.038	0.067

CHAPTER 8

LOWER COLORADO RIVER AUTHORITY

8.1 Introduction

With current reserve margins in excess of 35 percent and a commitment to aggressively pursue DSM opportunities, LCRA plans no additions to generating capacity over the next fifteen years. However, the demand projections prepared by the PUC staff suggest that LCRA may be slightly underestimating its capacity needs. Purchased power from utilities or cogenerators, still greater DSM activity, or construction of additional generating capacity may be necessary to ensure reliability in 2004 and beyond.

8.2 PUC Staff Base Case

The PUC staff base case assumes the projections of demand, fuel prices, and DSM program impacts developed by the Commission staff. Unfortunately, LCRA's existing DSM programs could not be modeled explicitly in LMSTM, since the necessary loadshape data were not available from LCRA in time to permit their inclusion in this analysis.

Figures 8.1 through 8.3 compare the utility-developed projections of peak demand and sales to the PUC staff's. Because LCRA experiences strong peak demand in both the summer and winter, projections for both seasons are provided. The strong winter peak demand is attributable to a high saturation of electric resistance heating equipment in the Texas Hill Country. For the later years of the forecast horizon, the Commission staff's demand projections exceed the utility's.

Only one hypothetical DSM program, the Refrigerator Efficiency Program, was evaluated for its potential contribution to the LCRA's resource plan. The air conditioner and water heater load control strategies described in Chapter 2 have already been implemented by LCRA. Adequate data were not available to specify a hypothetical Swimming Pool Timer Program.

Figure 8.1
Comparison of PUC Staff and Utility-Developed Adjusted Summer Peak Demand Projections: Lower Colorado River Authority

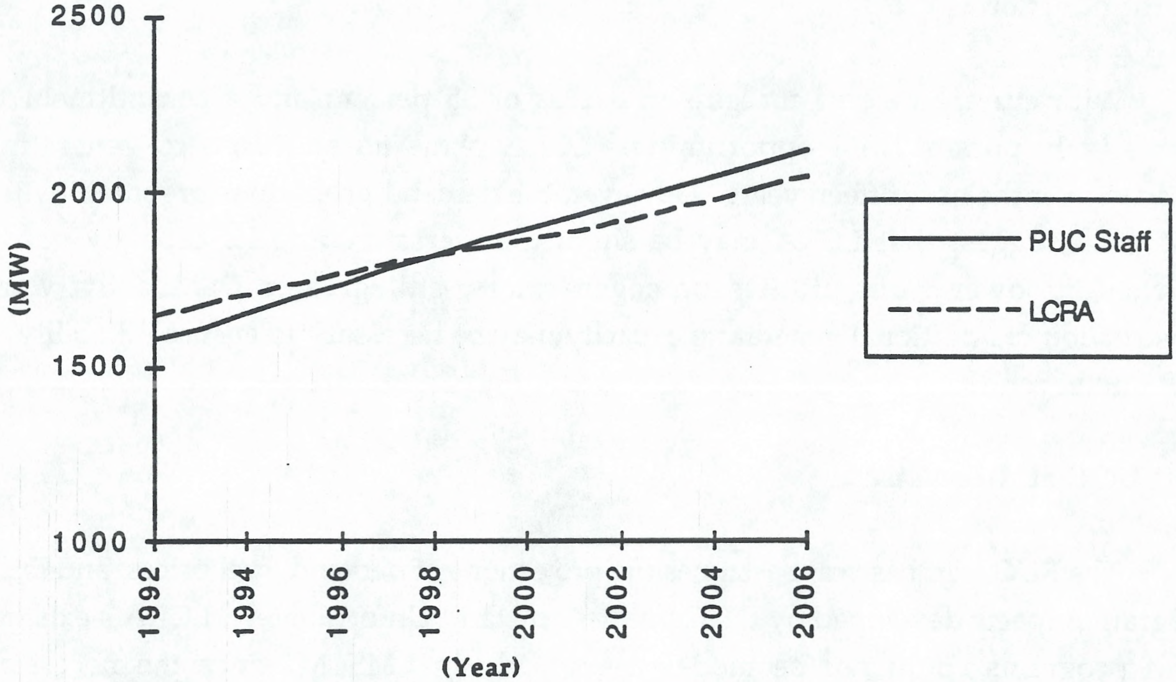


Figure 8.2
Comparison of PUC Staff and Utility-Developed Adjusted Winter Peak Demand Projections: Lower Colorado River Authority

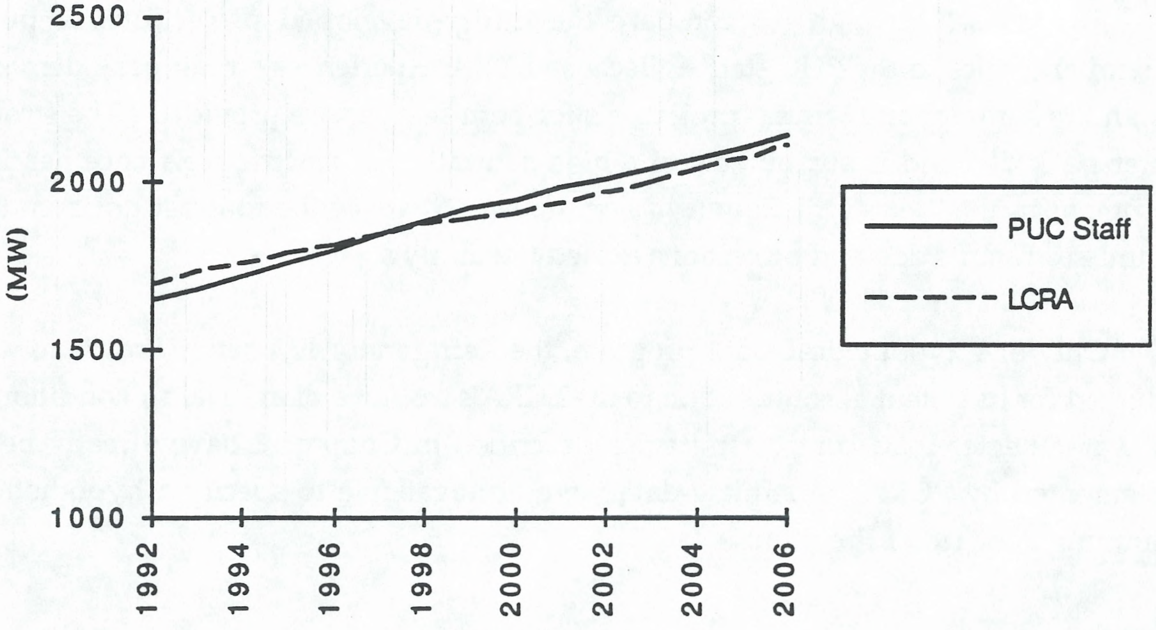
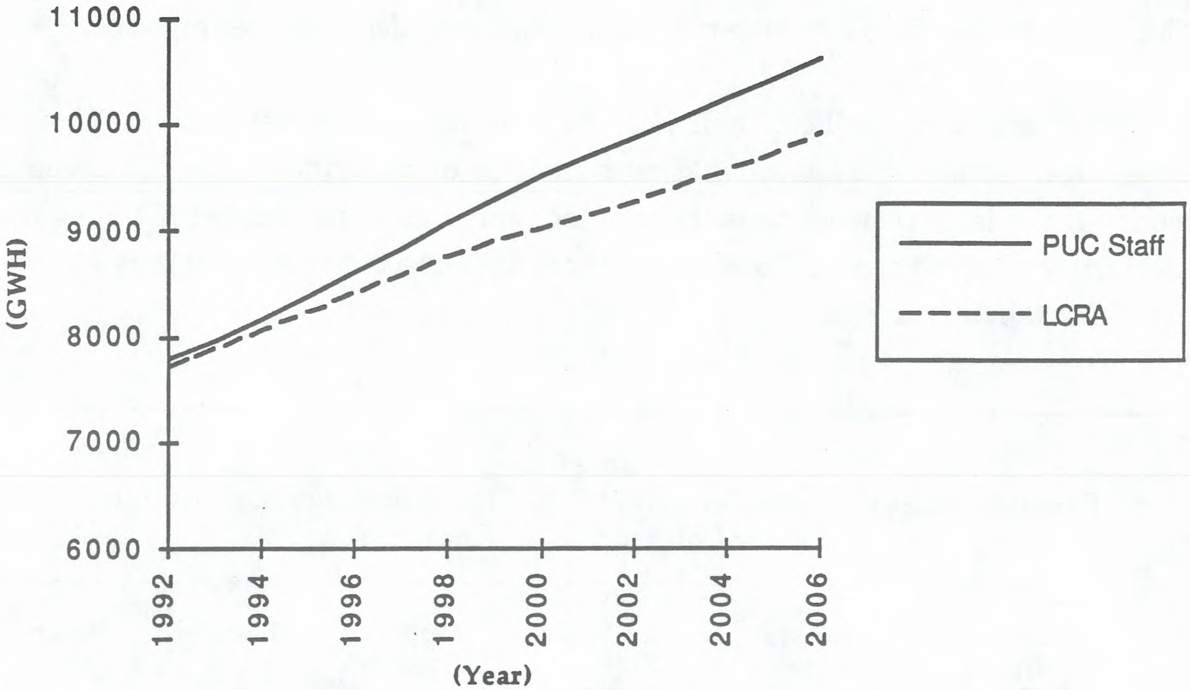


Figure 8.3
Comparison of PUC Staff and Utility-Developed Sales Projections: Lower Colorado River Authority



The hypothetical Refrigerator Efficiency Program passed neither the utility cost nor the total resource cost tests. This result may be attributable to the utility's relatively low avoided energy costs. In addition, additional capacity has little value to the utility until the later years of the forecast horizon, further constraining the benefit-cost ratios.

Based upon the results obtained from the DSM program screening, no additional DSM has been added to the PUC staff base case resource plan, beyond the amounts reflected in the Commission staff's adjusted load forecast. However, additional DSM should not be dismissed as a resource option by the utility or the Commission staff in future planning exercises. Further screening studies or solicitations for resource will undoubtedly reveal opportunities that were not uncovered through the limited analysis performed here.

The PUC staff base case adopts the utility's resource plan, with one exception. Because the Commission staff load forecasts are slightly higher than the utility's, additional capacity is required to satisfy the ERCOT and Commission staff minimum reserve margin target for the years 2004 and beyond. Additional capacity is assumed to come from firm cogeneration in this base case scenario, given the favorable economics associated with this resource and the utility's already relatively high reliance upon DSM. Table 8.1 provides a reserve margin calculation under these assumptions.

The results of the PUC staff base case scenario are presented in Tables 8.2 through 8.4. Projected system-wide rates may be of particular interest. Given the absence of any large planned capacity additions and a growing number of billing units (sales) from which to recover fixed costs, prices are expected to grow at very low rates throughout the forecast period.

Table 8.1
Reserve Margin Calculation under PUC Staff Base Case Assumptions: Lower Colorado River Authority

Year	PUC Staff Adjusted System Peak (MW)	Installed Capacity (MW)	Additional Firm Purchases (MW)	Net Capacity (MW)	Reserves (MW)	Reserve Margin (%)
1992	1,649	2,266	0	2,266	617	37
1993	1,683	2,266	0	2,266	583	35
1994	1,723	2,266	0	2,266	543	32
1995	1,764	2,266	0	2,266	502	28
1996	1,804	2,266	0	2,266	462	26
1997	1,847	2,266	0	2,266	419	23
1998	1,887	2,266	0	2,266	379	20
1999	1,922	2,266	0	2,266	344	18
2000	1,953	2,266	0	2,266	313	16
2001	1,985	2,266	17	2,283	298	15
2002	2,015	2,266	51	2,317	302	15
2003	2,045	2,266	86	2,352	307	15
2004	2,076	2,266	121	2,387	311	15
2005	2,109	2,266	159	2,425	316	15
2006	2,141	2,266	196	2,462	321	15

Table 8.2
Total Fuel Costs Comparison of Utility-Developed and PUC Staff Base Case Projections: Lower Colorado River Authority
(Thousands of Dollars)

Year	Utility Projection	PUC Staff Base Case Projection
1992	122,461	110,972
1993	119,766	109,134
1994	122,635	115,864
1995	130,141	125,168
1996	133,447	125,643
1997	139,267	139,142
1998	149,695	152,708
1999	159,074	164,350
2000	169,509	174,566
2001	180,022	193,136
2002	195,946	208,807
2003	N/A	223,972
2004	N/A	241,469
2005	N/A	254,265
2006	N/A	268,386

Table 8.3
Lower Colorado River Authority
Projected Fuel Consumption under PUC Staff Base Assumptions
(Thousand MMBtu)

Year	Natural Gas	Coal
1992	12,911	66,966
1993	16,637	64,855
1994	15,982	67,355
1995	16,927	69,433
1996	18,342	71,015
1997	22,690	69,483
1998	26,267	67,978
1999	26,274	71,422
2000	24,459	75,796
2001	28,773	73,088
2002	31,650	71,284
2003	32,113	72,645
2004	34,004	71,965
2005	33,068	74,702
2006	32,000	77,879

Table 8.4
Projected System-Wide Rates under PUC Staff Base Case Assumptions: Lower Colorado River Authority
(Dollars per kWh)

Year	Average Base Rate	Fuel Factor	Total Average Rate
1992	0.024	0.014	0.038
1993	0.025	0.013	0.039
1994	0.025	0.014	0.039
1995	0.025	0.015	0.039
1996	0.025	0.014	0.039
1997	0.024	0.015	0.040
1998	0.024	0.016	0.040
1999	0.023	0.017	0.040
2000	0.023	0.018	0.041
2001	0.022	0.019	0.042
2002	0.022	0.021	0.043
2003	0.022	0.022	0.044
2004	0.022	0.023	0.046
2005	0.022	0.025	0.047
2006	0.022	0.026	0.048

CHAPTER 9

SUMMARY AND CONCLUSIONS

9.1 Review of Analysis

This study was conducted by CES to assist the Commission staff in developing suggested integrated resource plans for each of the state's utilities and in addressing a number of relevant planning issues. These suggested base case resource plans are designed to provide a reasonable forecast of the likely utilization of various resources, utility costs, electricity prices, and fuel use under the PUC staff's planning assumptions. It is anticipated that further planning opportunities could be identified through competitive utility solicitations for supply-side and demand-side resources.

The analysis contained in this report has focused on six of the state's largest electric utilities. Using LMSTM and PROSCREEN, two state-of-the-art resource planning models, the current resource plans of each utility were analyzed and alternative resource planning strategies were studied to determine whether changes in utility resource plans could result in lower costs without jeopardizing reliability.

9.2 Summary of Results

The analysis presented in this report suggests that greater reliance on DSM programs and cogeneration, relative to present utility plans, can lead to lower utility revenue requirements and rates, without jeopardizing reliability. A number of generating unit additions presently planned by these utilities may be economically deferred beyond their current planned on-line dates by placing greater reliance upon these alternative resources.[10]

For five of the six utility systems analyzed in this study, at least one hypothetical DSM program appeared to be economical and beneficial from the utility and total resource cost perspectives. This finding would appear to support the contention that

---

[10]Many utilities are aware of the potential for greater reliance upon DSM to economically reduce future capacity requirements and plan to increase their dependence upon this resource as regulatory impediments are removed and incentives are introduced. Despite official filings in which many of the state's utilities indicate plans to reduce reliance upon firm cogeneration in the future as current contracts expire, some of the state's utilities "unofficially" acknowledge that purchases are likely to continue if cogeneration continues to be available at competitive prices.

each of these utilities faces cost-effective DSM opportunities that are not currently being exploited. However, no recommendations regarding specific DSM programs are offered here. Such recommendations must be determined through a more comprehensive screening exercise encompassing a greater number of prospective DSM strategies or through a solicitation for resources.

Some specific results are summarized in the following figures and tables. For the six utilities studied, increases in electric rates are likely to remain below expected inflation rates into the foreseeable future, as indicated in Figure 9.1.

Under the PUC staff base case assumptions, much of the projected increase in electricity consumption will be satisfied with natural gas generation. Figures 9.2 and 9.3 present projected fuel mix. Table 9.1 identifies the generating unit additions and retirements under the PUC staff base case scenarios described in Chapters 3 through 8.

Figure 9.1
Comparison of Average System-Wide Rates under PUC Staff Base Case Assumptions

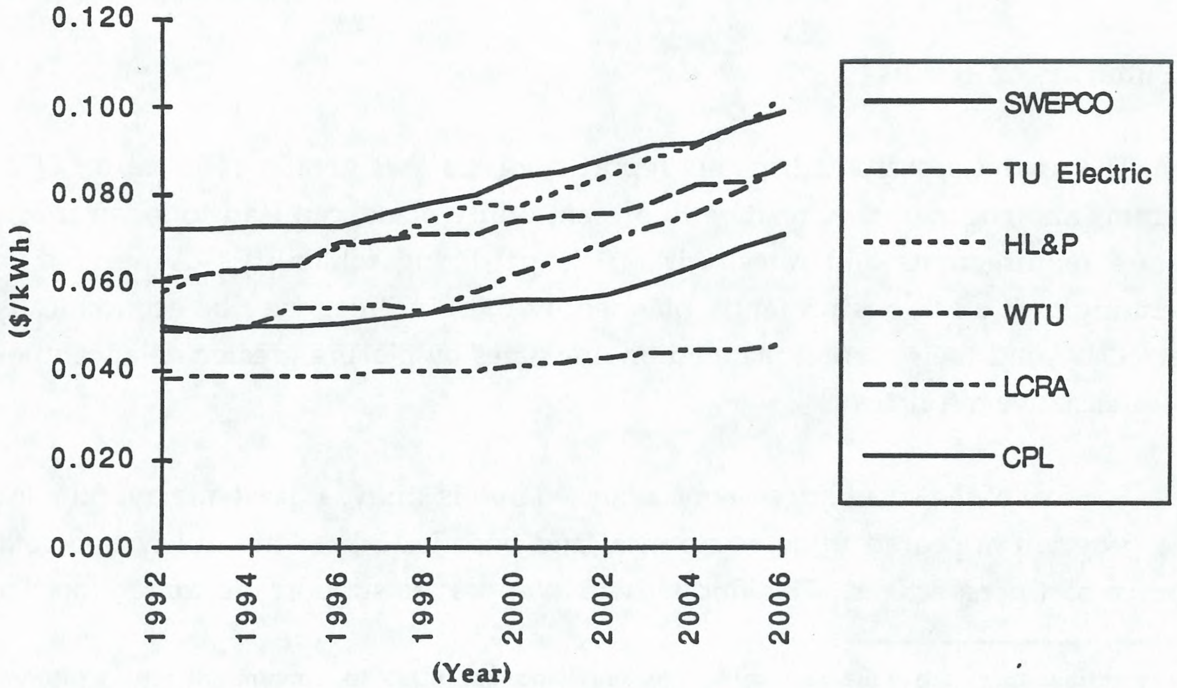


Figure 9.2
Projected Fuel Consumption for 1992
(Thousands MMBtu)

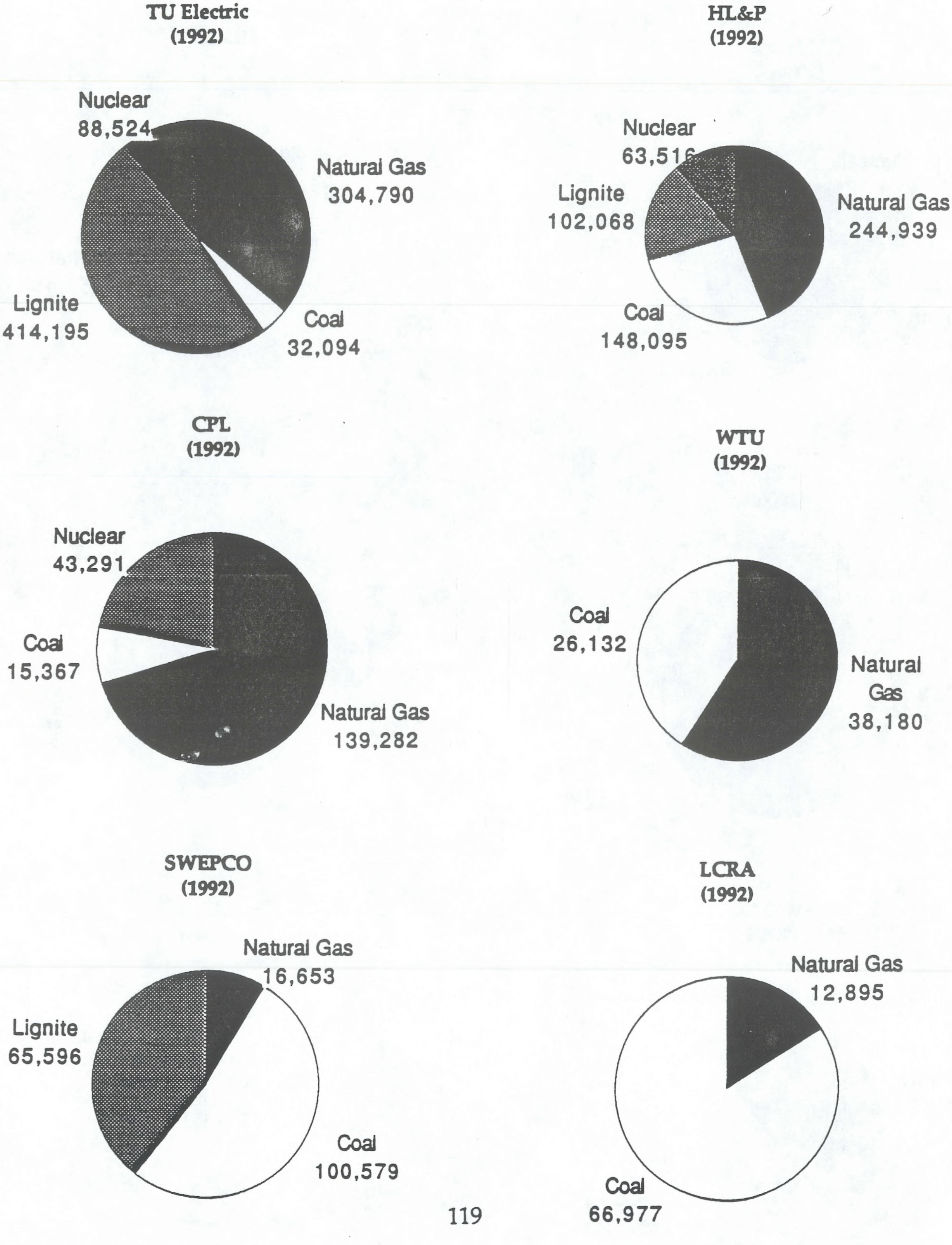


Figure 9.3
Projected Fuel Consumption for 2006
(Thousands MMBtu)

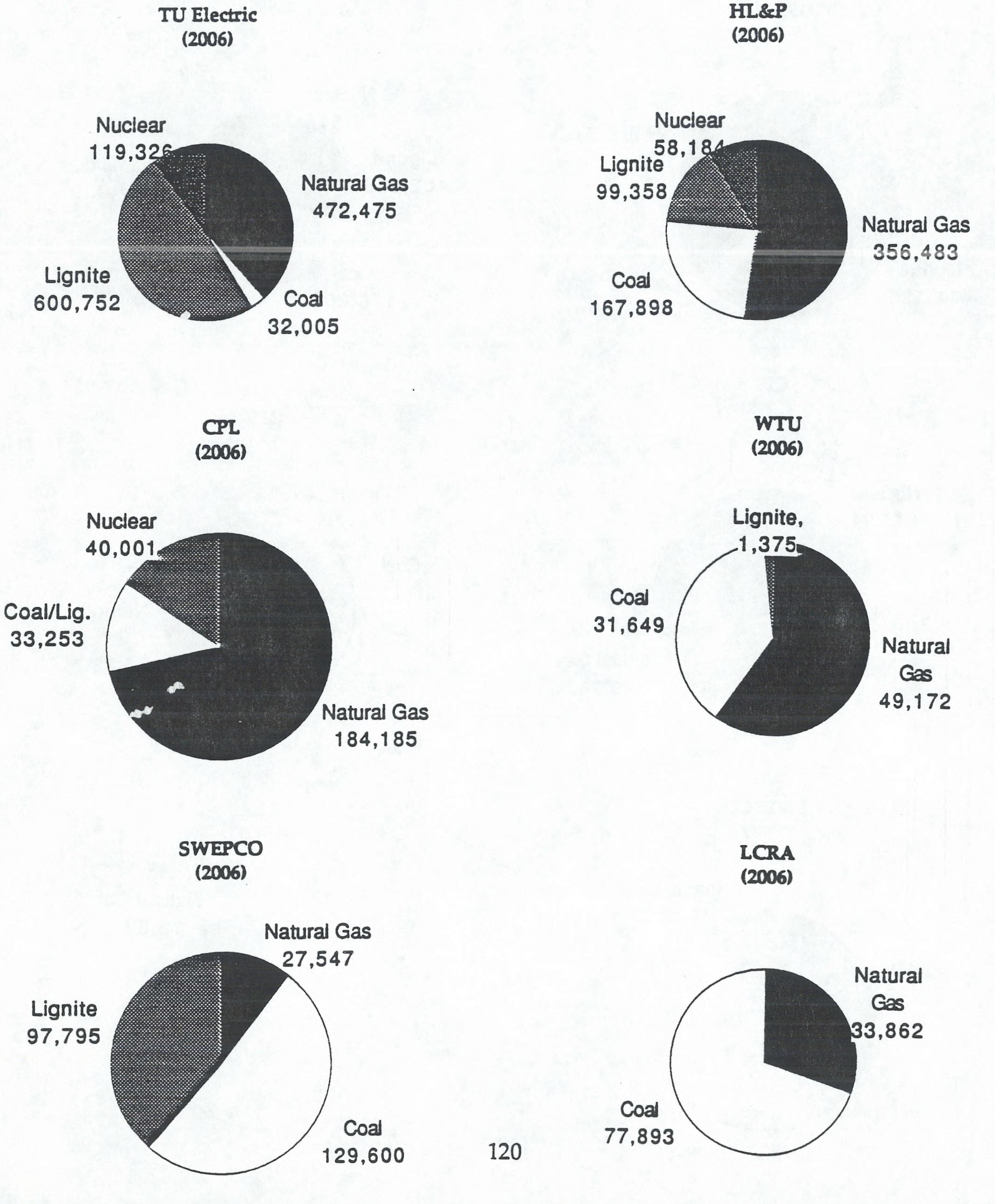


Table 9.1
Generating Unit Additions and Retirements Under PUC Staff Base Case Scenarios

Year	Utility	Plant	Unit	Capacity (MW)	Primary Fuel
1993	TU	Comanche Peak	2	1,150	URAN
2003	TU	Twin Oak	1	750	LIG
2005	TU	Twin Oak	2	750	LIG
1999	TU	Undesignated CC (CCCT1)	1	645	NG
2000	TU	Undesignated CC (CCCT2 1)	1	645	NG
1997	TU	Undesignated CT (COMBS001)	2	145	NG
1997	TU	Undesignated CT (COMBS002)	1	145	NG
2002	TU	Undesignated CC (CCCT 3 1)	1	620	
2004	TU	Undesignated CC (CCCT4 1)	1	620	NG
2001	TU	Undesignated CT (COMBS014)	1	136	NG
2001	TU	Undesignated CT (COMBS021)	2	136	NG
2003	TU	Undesignated CT (COMBS022)	1	136	NG
2003	TU	Undesignated CT (COMBS023)	2	136	NG
2005	TU	Undesignated CT (COMBS024)	1	136	NG
2005	TU	Undesignated CT (COMBS025)	2	136	NG
2006	TU	Undesignated CC (CCCT 5 1)	1	620	NG
2006	TU	Undesignated CT (COMBS026)	1	136	NG
2006	TU	Undesignated			
1992	HL&P	Upgrade	-	20	NG
1993	HL&P	Upgrade	-	30	NG
1993	HL&P	Upgrade	-	40	COAL
1994	HL&P	Upgrade	-	10	NG
1995	HL&P	Upgrade	-	10	NG
1995	HL&P	Dupont	-	158	NG
1996	HL&P	Upgrade	-	10	NG
1998	HL&P	Webster	1	110	NG
1998	HL&P	Webster	2	110	NG
2002	HL&P	(CCGTE01)	1	219	NG

Table 9.1 (continued)

Year	Utility	Plant	Unit	Capacity (MW)	Primary Fuel
2001	HL&P	Greens Bayou	3	110	NG
2001	HL&P	Greens Bayou	4	110	NG
2003	HL&P	(CCGTF01)	2	206	NG
2003	HL&P	(CCGTF02)	3	206	NG
2004	HL&P	(CCGTF03)	4	206	NG
2005	HL&P	(CCGTF04)	5	206	NG
2006	HL&P	(CCGTF05)	6	206	NG
2006	HL&P	(CCGTF06)	7	206	NG
1992	CPL	Oklaunion	1	2	SUB
2001	CPL	Repower Laredo	2	(89)	NG
2001	CPL	Laredo	1	(36)	NG
2002	CPL	Repower JL Bates	1	163	NG
2004	CPL	Repower LC Hill	1	173	NG
2004	CPL	Victoria	4	(45)	NG
2004	CPL	Lon C Hill	3	(158)	NG
2005	CPL	JL Bates	2	(111)	NG
2005	CPL	La Palma	7	(47)	NG
1992	WTU	Oklaunion	1	11	SUB
1992	WTU	Rerating	–	4	NG
1998	WTU	Abilene	4	(18)	NG
1998	WTU	Fort Stockton	2	(5)	NG
1998	WTU	Lake Pauline	1	(19)	NG
2000	WTU	WTU CC	1	114	NG
2000	WTU	Repower Rio Pecos	5	122	NG
2000	WTU	Rio Pecos	4,5	(41)	NG
2002	WTU	WTU CC	2	114	NG
2002	WTU	Lake Pauline	2	(27)	NG
2003	WTU	Paint Creek	1	(33)	NG
2005	WTU	Paint Creek	2,3	(87)	NG
2006	WTU	WTU CC	3	114	NG
2001	SWEPCO	Repower Wilkes	2	87	NG
2001	SWEPCO	Lieberman (1)	1,2	(56)	NG
2002	SWEPCO	Repower Wilkes	3	87	NG
2002	SWEPCO	Knox Lee (1)	2,3	(74)	NG
2003	SWEPCO	Lone Star (1)	1	(50)	NG
2006	SWEPCO	SWEPCO CC	1	218	NG
2006	SWEPCO	SWEPCO CT	1	146	NG
2006	SWEPCO	Knox Lee (1)	4	(83)	NG
2006	SWEPCO	Lieberman (1)	3,4	(220)	NG

KEY: NG=Natural Gas LIG=Lignite BIT=Bituminous Coal SUB=Subbituminous Coal URAN=Uranium

LONG-TERM ELECTRIC PEAK DEMAND

AND CAPACITY RESOURCE FORECAST

FOR TEXAS

1992

TECHNICAL APPENDIX

TO

MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS

APRIL 1993

THE PUBLIC UTILITY COMMISSION OF TEXAS

TECHNICAL INDEX

MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
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
Loop W. Weatherford-Calmont Line into Hilltop (BEPC)	Parker	69	AC	1.0	$1,129,400	*	Jul-93	Nov-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	0.0	$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:								
24	Additional substation projects							
24	Additional line uprgrade projects							
34	Additional new transmission line projects							
HL&P								
Baywood Loop	Harris	138	AC	1.9	$946,000	**	Dec-91	Mar-92
Global/Rollins Loop	Harris	138	AC	2.2	$1,100,000	**	Dec-91	Apr-92
Dupont Loop	Harris	138	AC	0.4	$9,000,000	*	Jan-94	Dec-94
T. H. Wharton Add Unit	Harris	345	AC	0.2	$11,200,000	***	Jun-94	Dec-95
T. H. Wharton Add Unit	Harris	345	AC	0.2	$6,700,000	***	Jun-95	Dec-96
T. H. Wharton Add 2 Units	Harris	345	AC	0.4	$21,000,000	***	Jun-96	Dec-97
Welsh-Monticello HVDC East Tie	Titus	345	AC/DC	0.0	$33,536,000	***	Jan-93	Dec-98
T. H. Wharton Add Unit	Harris	345	AC	0.2	$7,300,000	***	Jun-97	Dec-98
Greens Bayou Add 2 Units	Harris	138	AC	1.0	$17,000,000	***	Jun-98	Dec-99

TECHNICAL INDEX
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
including Substation Costs

	Project Name	Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
	Malakoff Temp. Tap	Henderson	69	AC	1.3	$3,300,000	*	Jan-00	Dec-00
	Greens Bayou Add 2 Units	Harris	138	AC	1.0	$16,500,000	***	Jun-99	Dec-00
	Polk-Eastside	Harris	138	AC	0.7	$4,100,000	*	Jun-99	Dec-00
	Cypress Double Tap	Harris	138	AC	4.5	$6,000,000	*	Jun-00	Jun-01
	S. R. Bertron Add Unit	Harris	138	AC	0.2	$6,900,000	***	Jun-00	Dec-01
	S. R. Bertron Add 2 Units	Harris	138	AC	0.5	$14,500,000	***	Jun-01	Dec-02
	Brookshire Loop	Waller, Fort Bend	138	AC	6.5	$6,900,000	*	Jun-02	Jun-03
	S. R. Bertron	Harris	138	AC	0.2	$7,600,000	***	Jun-02	Dec-03
	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
	Malakoff Loop	Henderson	345	AC	8.8	$71,600,000	*	Jun-01	Dec-04
GSU									
	Line 497	Jefferson	69	AC	1.0	$514,000	*	Oct-92	Jul-93
	Line 803	Montgomery	138	AC	2.7	$4,500,000	*	Apr-93	Oct-93
	Line 169	Montgomery	138	AC	1.7	$600,000	**	Apr-93	Oct-93
	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									
	Military Hwy - CFE	Cameron	138	AC	2.6	$1,308,000	*	May-92	May-92
	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
	Roma Tap-Roma	Starr	138	AC	7.0	$2,981,000	*	May-93	May-94
	Dilley Switching-Wormser	Frio, LaSalle, Webb	138	AC	82.0	$17,259,000	*	May-93	May-94
	N. Padre Tap-N. Padre	Nueces	69	AC	3.8	$1,755,000	**	May-95	May-95
	Mines Rd-Columbia-Asherton	Webb	138	AC	7.5	$3,600,000	*	May-95	May-96

TECHNICAL INDEX
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
including Substation Costs

	Project Name	Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
	Cabiness-S C C - Rodd Field	Nueces	138	AC	5.0	$5,119,000	*	May-96	May-97
	Welch-Monticello HVDC East Tie	Titus	345	AC/DC	0.0	$39,029,000	***	Mar-95	Mar-98
	Santo Nino-Heights	Webb	138	AC	2.8	$5,016,000	*	May-97	May-98
	N.E. Fulton-Fulton	Aransas	69	AC	4.3	$2,200,000	*	May-97	May-98
	W. Batesville-Eagle Pass	Maverick, Zavala	138	AC	55.0	$12,896,000	*	May-97	May-98
CPS									
	Grandview-Fern	Bexar	138	AC	2.4	$1,417,261	*	Oct-91	May-92
	Ball Park-Fern	Bexar	138	AC	1.2	$991,010	*	Oct-91	May-92
	Medina-Quintana	Bexar	138	AC	7.0	$1,775,241	***	Apr-93	Apr-93
	Quintana-South San Antonio	Bexar	138	AC	1.3	$2,295,293	*	Nov-92	Aug-93
	BAMC Loop	Bexar	138	AC	0.1	$1,245,605	*	Sep-93	May-94
	Howard Loop	Bexar	138	AC	4.9	$2,397,508	*	Nov-93	May-94
	Encino Park Loop	Bexar	138	AC	0.1	$3,071,981	*	Mar-94	Aug-94
	Stinson Field Reroute	Bexar	138	AC	3.0	$1,371,962	**	Dec-94	May-95
	Green Mountain Loop	Bexar	138	AC	0.0	$3,025,007	***	Jan-95	May-95
	Palo Alto Loop	Bexar	138	AC	1.0	$3,237,336	*	Mar-96	May-96
	Anderson Loop	Bexar	138	AC	0.2	$1,615,967	*	Mar-97	May-97
	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
	Harmony Hills-Castle Hills-Med Ctr breakoff	Bexar	138	AC	5.9	$1,522,685	**	Feb-98	May-98
	Hill Country-Scenic Hills	Bexar	138	AC	6.6	$6,410,093	*	Jan-99	May-99
	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
	Helotes-Grissom	Bexar	138	AC	7.0	$1,028,165	*	Mar-99	May-99
	Grissom-Marbach	Bexar	138	AC	5.1	$529,175	**	Mar-99	May-99
	Hill Country-Cagnon	Bexar	345	AC	19.5	$8,129,012	*	Feb-00	May-00
	Texas Research Loop	Bexar	138	AC	5.4	$5,084,999	*	Feb-01	May-01
	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

TECHNICAL INDEX
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
including Substation Costs

	Project Name	Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
	MM Lignite Loop	Bexar	345	AC	5.0	$1,780,348	**	Mar-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									
	Chaves-Urton	Chaves NM	115	AC	4.5	$1,407,000	*	Jan-92	Mar-92
	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
	Urton-Roswell City	Chaves NM	115	AC	2.7	$1,350,000	*	Aug-93	Oct-93
	Lynn-Graham	Lynn, Garza	115	AC	23.5	$4,195,000	*	Jun-93	Dec-93
	Roswell City-Roswell Interchange	Chaves NM	115	AC	3.8	$320,000	**	Feb-94	Mar-94
	Lanton Tap-Lanton	Lamb	115	AC	9.0	$2,839,000	*	Oct-93	Apr-94
	Lamb-Carlisle	Lamb, Hockley, Lubbock	230	AC	39.0	$5,220,000	*	Nov-93	Apr-94
	East Panhandle-Bowers	Gray	115	AC	4.6	$3,010,000	*	Jan-94	Jun-94
	Tolk-Tuco	Bailey, Lamb, Hale	345	AC	55.0	$12,310,000	*	Oct-94	Jun-95
	Brownfield Tap-Brownfield	Terry	115	AC	2.5	$950,000	*	Jan-96	May-96
SWEPCO									
	Marshall-North Marshall	Harrison	69	AC	3.5	$429,000	**	Jan-91	Apr-92
	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
	New Boston-Red River	Bowie	69	AC	3.9	$430,000	**	Jan-92	Jan-93
	Hooks-Red River	Bowie	69	AC	4.0	$415,000	**	Jan-92	Jan-93
	Gilmer-Purdue	Upshur	69	AC	11.4	$1,068,000	**	Feb-93	Jun-93

TECHNICAL INDEX
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
including Substation Costs

Project Name	Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
Bann- S.E. Texarkana	Bowie	138	AC	12.4	$3,676,000	**	Jan-93	Dec-93
Taylor- Texarkana	Bowie	69	AC	3.1	$330,000	*	Jan-93	Dec-93
Grand Saline- N. Mineola	Smith, VanZandt, Wood	138	AC	16.5	$2,730,000	*	Jan-93	Dec-93
Kilgore-Sabine	Gregg	69	AC	6.4	$525,000	**	Feb-94	Jun-94
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
Petty- Pittsburg	Titus,Camp	138	AC	9.7	$2,217,000	*	Jan-95	Dec-96
Karnack- Woodlawn	Harrison	69	AC	11.3	$605,000	**	Jan-96	Dec-96
Mt. Pleasant- Petty	Titus	69	AC	2.1	$119,000	**	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
North Mineola- Quitman	Wood	138	AC	9.4	$2,860,000	*	Jan-97	Dec-98
Beckville- Rock Hill	Panola	69	AC	4.1	$195,000	**	Jan-99	Dec-99
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

TECHNICAL INDEX
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
including Substation Costs

Project Name	Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates: Begin	Estimated Construction Dates: Complete
McNeil-Gabriel	Travis, Williamson	138	AC	21.0	$5,269,000	**	NYD	Jun-94
Kerr City-Rim Rock	Kerr	138	AC	2.3	$2,706,000	**	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
Gillespie-Nimitz	Gillespie	138	AC	4.0	$2,960,000	**	NYD	Jun-96
Buda-Manchaca	Hays, Travis	138	AC	7.0	$2,300,000	**	NYD	Jun-96
COA								
Line 978/980	Travis	138	AC	4.0	$900,000	**	Dec-92	Jun-93
Line 974/975	Travis	138	AC	5.0	$6,091,800	*	Jun-93	Sep-93
Line 987	Caldwell, Travis	138	AC	17.0	$22,314,950	*	NYD	Jun-94
Line 949	Travis	138	AC	4.0	$600,000	**	Jun-92	Jun-94
Line 976	Travis	138	AC	4.0	$6,657,700	*	NYD	Dec-94
Line 962	Travis	138	AC	9.0	$4,000,000	*	NYD	Jun-95
Garfield-Hicross	Travis	138	AC	14.0	$4,200,000	**	NYD	Jun-95
Line 915/916/985/981	Travis	138	AC	9.0	NYD		NYD	Jun-96
Line 809	Travis	69	AC	2.0	NYD		NYD	Jun-97
Line 989	Travis	138	AC	4.0	NYD		NYD	Jun-98
Line 977/979	Travis	138	AC	8.0	NYD		NYD	Jun-98
Line 982	Travis	138	AC	4.0	NYD		NYD	Jun-98
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	$3,29[illegible],467	*	Dec-91	Jun-92
Bronte Tap	Coke, Runnels	138	AC	3.8	$1,792,000	*	Jun-93	Jun-94
Menard-Sonora	Menard, Schleicher, Sutton	138	AC	59.3	$4,847,000	*	Jun-93	Jun-94
Clyde Tap	Callahan	138	AC	2.6	$1,011,000	*	Jun-94	Jun-95
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

TECHNICAL INDEX
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
including Substation Costs

	Project Name	Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Estimated Construction Dates Complete
	Lake Pauline-West Childress	Hardeman, Childress	138	AC	37.2	$4,085,000	*	Jun-00	Jun-01
	Brady Plant-S. Brady	McCulloch	69	AC	2.5	$255,000	**	Jun-00	Jun-01
	Alpine- Ft. Davis	Brewster, Jeff Davis	69	AC	28.5	$1,354,000	*	Jun-00	Jun-01
EPE									
	Rio Grande-ASARCO	El Paso TX	69	AC	4.8	$430,200	**	Dec-91	Feb-92
	CFE, Mex/ Diablo-Juarez	Chihuahua MX, El Paso TX	115	AC	2.4	$709,400	*	Apr-91	Jun-92
	Horizon SS-Pelicano/ Horizon Substation	El Paso TX	115	AC	5.0	$183,500	*	Jul-91	Dec-92
	L.V.I.A. Substation	El Paso TX	69	AC	<1	$523,100	*	Apr-92	Mar-93
	Santa Theresa Substation/ Diablo-Santa	Dona Ana NM	115	AC	11.4	$1,916,950	*	Nov-91	Apr-93
	Rio Grande-Mesa	El Paso TX	115	AC	2.3	$301,920	*	Nov-92	Apr-93
	Anthony-Montoya	Dona Ana NM	115	AC	10.2	$928,385	**	Jul-92	May-93
	Butterfield-Ft. Bliss	El Paso TX	115	AC	1.8	$813,280	*	Aug-92	Jun-93
	Las Cruces Substation	Dona Ana NM	115	AC	Line Repair	$3,240,000	*	Oct-92	Jan-94
	Pellicano Substation	El Paso TX	115	AC	6.0	$1,375,000	*	Feb-93	Apr-94
	Santa Fe-Sunset	El Paso TX	69	AC	1.4	$120,600	**	Dec-93	Apr-94
	Cromo-Dyer	El Paso TX	115	AC	6.0	$750,000	**	Sep-93	May-94
	Fairground Substation/ Fairground-Picacho	Dona Ana NM	115	AC	2.5	$730,000	*	Mar-93	Jun-94
	Felipe Substation/ Horizon-Felipe	El Paso TX	115	AC	12.0	$1,829,000	*	Feb-94	May-95
	N.W. 3 Substation/ N.W. 3- Montoya	El Paso TX	115	AC	8.0	$1,595,000	*	Apr-94	May-95
	Montoya-Thorn	El Paso TX	115	AC	3.0	$290,000	**	Nov-94	Jun-95
	Thorn-Rio Grande	El Paso TX	115	AC	4.9	$419,200	**	Jul-94	Jun-95
	Anthony Substation	Dona Ana NM	115	AC		$165,000	***	Jan-95	Jun-95
	Salopec-Anthony	Dona Ana NM	115	AC	17.5	$1,597,771	**	Oct-95	Jun-96

TECHNICAL INDEX
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
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
	S. Teresa-Montoya	Dona Ana NM	115	AC	4.6	$603,250	*	Aug-97	Apr-98
	NWSS Switching Station/ NWSS-Newman	El Paso TX	115	AC	3.8	$821,600	*	Sep-98	May-99
	Rio Grande Substation	Dona Ana NM	115	AC	0.0	$1,024,000	***	Jan-00	May-00
	Leo-Dyer	El Paso TX	69	AC	4.4	$395,100	**	Dec-00	Jun-01
TNP									
	West Columbia Main-Phillips #3	Brazoria	138	AC	9.8	$975,000	**	May-92	Mar-93
	138-8 To South Shore	Galveston	138	AC	7.2	$1,720,000	*	Jul-92	Aug-93
	Lakepointe-Texas Instruments	Denton	138	AC	2.7	$2,000,000	*	Jan-94	Dec-94
	Glen Rose-Walnut Springs	Bosque, Hood, Somervell	138	AC	9.8	$1,045,000	**	Jan-94	Dec-94
	Glen Rose-Squaw Creek	Hood, Somervell	138	AC	4.7	$835,000	*	Jan-95	Dec-95
	138 POD - Squaw Creek	Hood, Somervell	138	AC	13.0	$3,060,000	*	Jan-95	Dec-95
	Clifton-Walnut Springs	Bosque	138	AC	26.3	$4,471,000	*	Jan-99	Jun-99
	Coryell County-Gatesville #2	Coryell	69	AC	1.6	$105,000	**	Jan-00	Dec-00
BEPC									
	Rockett-Trumbull	Ellis	69	AC	2.9	$4,628,150	*	CCN Denied:	Dkt. No. 10733
	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
	Brock-Liveoak	Parker	69	AC	4.5	$1,036,750	**	Jan-94	Jun-94
	Windsor S.W.-Gatesville	McLennan, Coryell	138	AC	20.0	$7,541,650	*	Jan-94	Jun-94
	Georges Creek-New Hope	Johnson, Somervell	69	AC	7.3	$2,220,350	*	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

TECHNICAL INDEX
(Continued)
MAJOR TRANSMISSION LINE CONSTRUCTION PROJECTS
including Substation Costs

Project Name	Counties	Voltage (KV)	AC/DC	Length (circuit miles)	Estimated Total Cost		Estimated Construction Dates Begin	Complete
Emmett-Richland	Navarro, Ellis, Hill	69	AC	20.0	$5,296,900	*	Feb-94	Jun-94
Miller-Palo Pinto	Palo Pinto	138	AC	7.7	$682,400	**	Feb-94	Jun-94
Liveoak-North Texas	Parker	69	AC	7.7	$1,893,850	**	Jan-95	Jun-95
Gibbons Creek-Roans Prairie	Grimes	69	AC	8.0	$3,741,850	*	Feb-96	Jun-96
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
Port Lavaca Tie	Calhoun	69	AC	0.5	$1,103,000	*	Jan-92	Oct-92
Riviera Tie	Kleberg	69	AC	4.0	$2,836,000	*	Jan-94	Jun-94
Seaway HLP Tie	Brazoria	138	AC	8.0	$2,924,000	*	Jan-95	Jun-95
MEC								
Medina-Uvalde (CPL)		138	AC	3.0	$2,047,538	*	Mar-95	Mar-96
LPL								
South Sub Extension	Lubbock	69	AC	3.0	$2,225,000	*	Oct-91	May-92
TMPA								
Bridgeport Tap-E. Bridgeport	Wise	138	AC	7.7	$1,526,000	**	Nov-91	Apr-92

Note:

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