LONG TERM ELECTRIC PEAK DEMAND
AND CAPACITY RESOURCE FORECAST
FOR TEXAS
1990

VOLUME III

PUC STAFF ECONOMETRIC ELECTRICITY
DEMAND FORECASTING SYSTEM

MARCH 1991

THE PUBLIC UTILITY COMMISSION OF TEXAS

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ABSTRACT

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

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

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

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

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

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

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

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CHAPTER ONE

ELECTRIC DEMAND FORECASTING PROJECTS AT THE COMMISSION

Overview

In the past seven years, the Electric Division (formerly the Economic Research Division) of the Public Utility Commission of Texas (PUCT) has initiated three distinct projects designed to produce accurate, flexible, and realistic independent projections of the demand for electricity to be faced by the larger generating electric utilities in Texas. These projects are:

1. The Econometric Electricity Demand Forecasting System
2. The End-Use Energy Modeling and Forecasting System
3. The Time-Series and Bayesian Forecasting Systems

The Econometric Electricity Demand Forecasting System seeks to statistically estimate the behavioral relationships among the various determinants of electricity consumption, such as weather, population, employment, personal income, electricity prices, prices of alternative energy sources, and industrial production. Future electricity consumption is projected based on historical relationships and forecasts of these demand determinants or "explanatory variables." Energy projections are made at the customer-class level, then converted to demand and aggregated to a system peak through the use of the Hourly Electric Load Model (HELM). A database containing over 7,000 time-series variables provides data input to this set of models. Numerous improvements have been made to this forecasting system since its results were reported in the Commission's **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988.**

The End-Use Energy Modeling and Forecasting System, completed earlier this year, is a three-phased project examining the end-uses of energy consumption in Texas. End uses examined include air conditioning, space heating, refrigeration, dishwashing, lighting, irrigation, and industrial processes. Changes in the stock of energy-intensive equipment, appliance efficiencies, equipment usage patterns, and the determinants of these factors (demographic patterns, technology, laws and regulations, relative fuel prices, climatological factors, etc.) are given explicit attention.

A basic end-use modeling framework for electricity demand in Texas was developed during the first three years of the End-Use Modeling Project. During the following two years, a state-of-the-art modeling system was developed under the sponsorship of the Electric Power Research Institute (EPRI). Interim reports served to mark the completion of the most recent funding of the project.

The End-Use Modeling System provides a means to explore a variety of conservation and load management strategies. The electricity demand projections derived from this system also provide a valuable validity-check upon the staff's econometric forecasts. The use of end-use models is useful for forecasting electricity demand and consumption, and for evaluating alternative programs.

The Time-Series and Bayesian Forecasting Systems provide alternative statistical methods for producing short-term and long-term forecasts. Time-series methods investigated by the staff include Kalman filter models, ARIMA models, and transfer function models. ARIMA models of quarterly peak demand were presented and discussed in Volume III of the 1986 Long-Term Forecast. State Space modeling is used in some of the customer forecasting models.

The Bayesian Forecasting System is based upon an approach which formally incorporates information found outside the sample period into the modeling process. In the 1988 Load Forecast Report, the load forecast for the City of Austin is based on results from a Bayesian linear regression model. The Bayesian Forecasting System is not used in the 1990 Load Forecast Report.

The pursuit of several distinct forecasts permits the Commission staff to apply the unique capabilities of each approach. End-use models are considered by some to be superior in addressing conservation and load management issues. Econometric models are typically more useful in studying electricity demand's responsiveness to energy prices and the impact of weather and economic activity on energy demand. Recent studies sponsored by Battelle Laboratories and the Electric Power Research Institute confirm the accuracy of time-series methods in short- and medium- range peak demand forecasting applications. Bayesian methods are becoming more prevalent in applied statistical work. The results from each of these forecasting systems provide a useful frame of reference when analyzing forecast results from other methods and sources.

Current Forecasting Approach

The staff of the Public Utility Commission of Texas is presently pursuing three distinct projects designed to provide policy-makers , the Texas power industry, and the public with accurate independent estimates of the future electricity demand to be faced by each of the state's major generating electric utilities. These projects are:

1. The Econometric Electricity Demand Forecasting System

2. The End-Use Energy Modeling and Forecasting System

3. State Space Modeling and Forecasting System

These projects have been extensively integrated with a number of other ongoing strategic planning activities at the Commission.

To provide peak demand estimates for this report the Commission staff is relying primarily upon the Econometric Electricity Demand Forecasting System. This forecasting system consists of simultaneous equation systems, ranging up to 65 equations in size, that provide sales and price projections at the customer-class level of detail. Separate models are developed for each major generating utility in the state. Each model seeks to statistically estimate the behavioral relationships among electricity demand and various demand determinants such as weather, population, employment, personal income, electricity prices, prices of alternative energy sources, and industrial production. Each forecasting model actually consists of four submodels:

1. Electricity Sales Submodel

2. Electricity Prices Submodel

3. Utility Cost Submodel

4. Customer Submodel

These submodels are solved simultaneously to yield a projection of a utility's total electricity sales. The database input to this forecasting system is developed from a variety of government, university, and private sources. Projections of demand determinants (employment, population, energy prices, etc.) are developed in-house or obtained from other reputable forecasting sources such as Data Resources, Inc. (DRI), Wharton-Econometric Forecasting Associates (WEFA), The Texas Economic Forecast from Perryman Consultants, INC. (Baylor), Bureau of Economic Analysis at the U.S. Department of Commerce, and the Comptroller of Public Accounts for the State of Texas among others.

The End-Use Energy Modeling and Forecasting System consists essentially of the Hourly Electric Load Model (HELM), the Residential End-Use Energy Planning System (REEPS), and the Commercial End-Use Model (COMMEND). HELM is used to translate the forecast of sales to a projection of peak demand. The staff employs REEPS to provide a statewide estimate of demand savings as a result of the National Appliance Energy Conservation Act (NAECA). The projection of savings, estimated at the state-wide level, are allocated to the various service areas. COMMEND projects annual commercial sector energy consumption and load curve by end-use and building type. Estimates of commecial building floor space and projected energy prices are key inputs into this model. COMMEND's results provide a validity check on the output of the other systems.

Econometric and State Space modeling techniques are used to generate projections of number of customers in each utility's service areas. In those cases where State Space models were superior to the econometric approach, the former modeling approach was relied upon.

State Space models with important and useful features have become a permanent tool used by the Commission Staff in their modeling activities. Some of these features include robustness, less data intensiveness, reliance on minimized forecast error methodology, as well as a superior methodology for model identification.

Commission Staff provides forecasts of electricity sales by major rate classes and system peak demand for thirteen major generatng electric utilities in Texas. These utilities are listed below and their actual models appear in Appendix A:

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

CHAPTER TWO

ECONOMETRIC FORECASTING SYSTEM

Overview

Simultaneous equation econometric models have been established 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 contain four submodels, that interact to produce forecasts of sales, prices, fuel costs, and number of customers:

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

The relationship between these four submodels is graphically depicted in Figure 2.1.

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 Price 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 averaged fixed costs over a historical period.

Fuel and fixed costs are determined within the utility cost submodel. The Utility Cost Submodel has two distinct components: a fuel cost module and a fixed-cost module. 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(mainly power plants and transmission and distribution facilities) and are "fixed" in the sense that they do not fluctuate with generation or sales levels. 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 a publicly-owned utility. The major exception is O&M, which has a variable component. Each utility's O&M projection, as presented in the forecast filings, is incorporated into the staff's fixed cost calculations for the Utility Cost Submodel.

Utility fuel expenses are simulated using a simple "economic merit order" approach, based on the premise that (if technical restrictions permit) 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 module. Sales estimates are obtained from the Electricity Sales Submodel.

A utility's customers are projected based on anticipated population and growth within the utility's service area as well as historical customer growth patterns. As in the other three submodels, statistical techniques are extensively relied upon in the Customer Submodel. The customer submodel is solved independently and its forecasts are used as inputs for the other submodels.

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.

Four of the thirteen utilities under study are multi-jurisdictional. That is, they serve customers in other states as well as in Texas. These utilities include Southwest Public Service Company (SPS), Southwestern Electric Power Company (SWEPCO). Gulf States Utilities Company (GSU), and El Paso Electric Company (EPE). The Staff constructs submodels that account for the unique characteristics of each portion of a utility's operation. As a result, separate submodels may differ across a utility's operation.

Electricity Sales Submodel

The Electricity Sales Submodel (Figure 2.2) 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. The major customer groups treated independently in this submodel are:

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

The Electricity Sale 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 (millions 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 ($ per MCF)
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. That is, as incomes increase, consumers 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 ($ per MCF)
t	=	Time Period (calendar quarter)
$b_0 ... b_5$	=	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 somewhat exemplary:

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

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 ($ per MCF)
t	=	Time Period (calendar quarter)
$b_0 ... b_4$	=	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 Price Submodel

The main purpose of this submodel (Figure 2.3) 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 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:

$$AP_{i,t} = b_0 + b_1 (AFIXED_t) + b_2 (AFUEL_t) + e_t$$

where:

$AP_{i,t}$	=	Average Price of Electricity to Customer Class i
$AFIXED_t$	=	Four-Quarter Moving Average of Fixed Costs Divided by the Four-Quarter Moving Average of Total Sales
$AFUEL_t$	=	Average Fuel Cost (Total Fuel Expense divided by Total Sales)
t	=	Time Period (calendar quarter)
$b_0 ... b_3$	=	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. Note that with regard to the 1986 forecast, this equation has been altered. Dummy variables to indicate the change from "automatic fuel adjustment clauses" to "fixed fuel factors" have been deleted. It was concluded that forecasting performance was not enhanced by such variables.

Utility Cost Submodel

The Utility Cost Submodel (Figure 2.4) provides forecasts of a utility's fuel expenses and fixed costs to the Electricity Price Submodel, which in turn provides price projections to the Electricity Sales Submodel. The determination of fuel expenses and fixed costs has been modified somewhat from earlier forecasts. In particular, Staff has modified the fuel cost module to better reflect the impact of fuel price differentials on generation decisions over the forecast period.

Fuel Cost Module The projection of costs within the sales forecasting model seeks to avoid forecasting bias common when variable costs are determined exogenously. Projection of a utility's generation or fuel cost must, at least in part, be based either on a forecast or on assumptions concerning future sales or generation. Similarly, a projection fed through price variables of cost 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 that use the projected prices as input, a forecasting bias would be introduced.

Fuel expenses are 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 (technical conditions permitting), the logic of this submodel may be represented as:

Fuel Cost Module

$$UC_{it} = (\text{Fuel Price}_{it}) * (\text{Heat Rate}_{it})$$

[Unit Cost of Production by Fuel Type i at time t $/KWH]	[$/MMBTU Fuel Type i at time t]	[MMBTU/KWH Fuel Type i at time t]

$i = 1,...,7$

where:

1 = Purchase Power

2 = Hydroelectric

3 = Lignite

4 = Nuclear

5 = Coal

6 = Natural Gas

7 = Cogeneration

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

Subject to:

(1) Generation:	Generation $Requirement_t$ (KWH) = ($Sales_t$ + $Losses_t$ + Company Use_t)
(2) Unit Production:	$KWH_{it} < (CAPF_{it}) (CAP_{it})$ (2,190 hours)
(3) Consumption and Production Balance:	$\Sigma_i \ KWH_{it} >$ Generation $Requirements_t$ (KWH)

where:

TFUELC	=	Total Fuel Cost
SALES	=	From Electricity Sales Submodel
CAPF	=	Capacity Factor
CAP	=	Capacity
2,190	=	Hours in Calendar Quarter
i	=	Fuel or Generation Unit Type
t	=	Time Period (calendar quarter)

Generation requirements by fuel type are determined by total generation requirements, capacity factors, and heat rates. 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. In the previous PUCT forecasts, a hierarchy of units by fuel costs within each quarter was established previously and maintained throughout each time period. Because the relative prices of fuels historically have changed and are predicted to change over the forecast period, the model has been altered in the 1990 forecast to capture those changes. The increased flexibility of the model should yield estimates of the cost of fuel purchased that are more reliable than previous projections.

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). In addition, some flexibility of operation of baseload units is incorporated into fuel cost modules to take advantage of low spot market fuel prices.

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 contrast to the **Long-**

Term Peak Demand and Capacity Resource Forecast for Texas 1988, utility-specific data are used on average fuel costs, heat rates, and capacity factors to reflect variations among utilities. 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.

NOTE: The actual programming statements in the computer code are somewhat different than the statements given above. The algorithm used is presented below.

Step 1: Obtain the unit variable cost (i.e., fuel cost or purchased power cost of producing one MWH of electricity) of different plants and purchased power sources.

Inputs: Heat rates and fuel prices of different plants and purchased power prices from utility and non-utility sources.

Step 2: Obtain the maximum generating capabilities of different plants and purchased power sources.

Inputs: Capacity and capacity factors of different plants and purchased power sources.

Step 3: In each time period:

a) Rank the plants and purchased power sources by unit variable costs.
b) Call the cheapest plant, Plant A, the next cheapest plant, Plant B, the next cheapest plant, Plant C, and so on.
c) Name the corresponding unit variable cost. UFCA, UFCB, UFCC, and so on.
d) Name the corresponding maximum generation capabilities as GCA, GCB, GCC, and so on.

Step 4: In each time period, define:

a) Generation requirement from Plant A

= { GCA if total generation requirement > GCA
Total generation requirement otherwise }

b) Variable cost for Plant A = generation requirements from Plant A * UFCA

c) Generation requirement for Plant B

= { GCB if (total generation requirement-GCA)>GCB
Total generation requirement - GCA if (i) (total generation requirement)>GCA & (ii) (total generation requirement-GCA)<GCB
0 otherwise }

d) Variable cost from Plant B = generation requirements from Plant B * UFCB

e) Generation requirement from Plant C

= { GCC if (total generation requirement-GCA-GCB)>GCC
Total generation requirement - (GCA-GCB) if (i) (total generation requirement-GCA)>GCB & (ii) (total generation requirement-GCA-GCB)< GCC
0 otherwise }

f) Variable cost for Plant C = generation requirements from Plant C * UFCC

Similarly, variable cost for each of the other plants is determined

Step 5: In each time period, define: Total variable cost = variable cost for Plant A + variable cost for Plant B + variable cost for Plant C + and so on.

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

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

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
PPC	=	Total Cost of Purchased Power From Other Utilities
COGC	=	Total Cost of Purchased Power From Cogerators

However, the actual available data concerning each utility's fuel costs are based on fuel purchases. A "mismatch" commonly occurs between 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 a constant ratio between sales and generation requirements and of an inventory costing method. A simple stochastic equation was used to correct for this mismatch:

$$CFP_t = b_0 + b_1 TF_t + e_t$$

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

Fixed Cost module Two different approaches 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.

In contrast, 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. In a few cases where these data were unavailable, interpolations are utilized. Allowed rate of return, weighted cost of debt factors, and ratebase amounts are taken from Final Orders issued by the Public Utility Commission of Texas (PUCT).

In order to forecast each of the fixed cost categories it is first necessary to project a total plant value. 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:

$$(P_{it}-P_{it-1}) / CI_i = b_1 \ln(POP_t) + e_t$$

where:

P_i = Plant

CI = Cost Index

POP = Service Area Population

t = Time Period

i = Plant Type (Transmission[1], 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 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 (1975-1989)

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

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1 Many utilities reported the estimated costs of transmission line construction projects in response to Request 34 of the Load and Capacity Resource 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.

NP = Net Plant
TOTP = Total Plant in Service
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 is assumed that no construction work in progress (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. In order 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 are additional costs that are added to the fixed costs described above. There is a capacity charge associated with purchase a power as well as with cogeneration purchases. If applicable, these charges are added to FC yielding total fixed costs.

Customer Submodel

The Electricity Sales Submodel 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 (Figure 2.5). These models are run on a microcomputer using a multiple regression program.

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

$$RC_t = a_0 + a_1 (POP_t) + (\text{AR Process of Error Term})$$

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

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
$a_0 \ldots a_1$	= Coefficients to be estimated
$b_0 \ldots b_2$	= 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

FIGURE 2.1

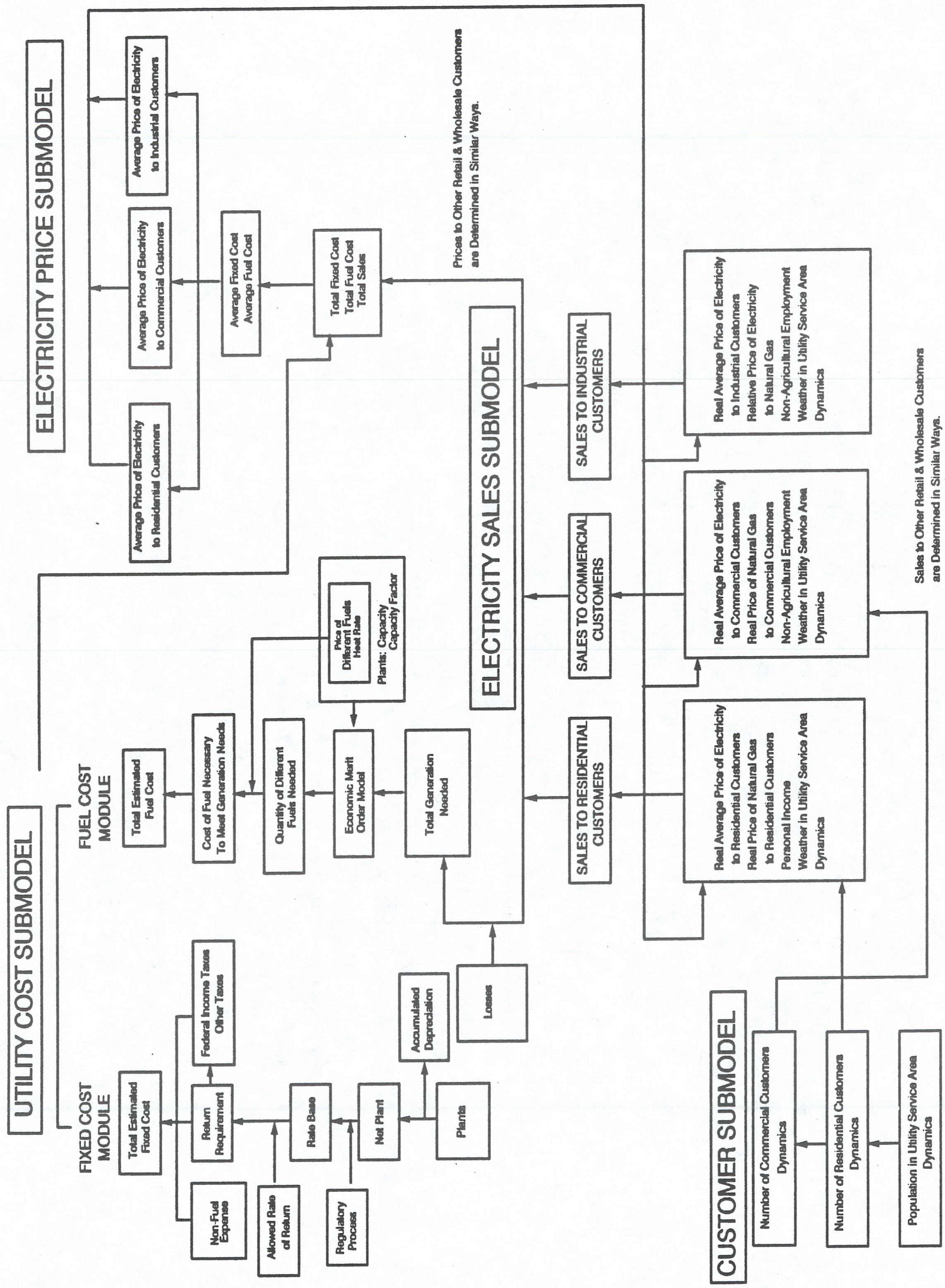

ELECTRICITY PRICE SUBMODEL
Average Price of Electricity to Residential Customers
Average Price of Electricity to Commercial Customers
Average Price of Electricity to Industrial Customers
Average Fixed Cost Average Fuel Cost
Total Fixed Cost Total Fuel Cost Total Sales
Prices to Other Retail & Wholesale Customers are Determined in Similar Ways.
UTILITY COST SUBMODEL
FUEL COST MODULE
Total Estimated Fuel Cost
Cost of Fuel Necessary To Meet Generation Needs
Quantity of Different Fuels Needed
Price of Different Fuels Heat Rate
Plants: Capacity Capacity Factor
Economic Merit Order Model
Total Generation Needed
FIXED COST MODULE
Total Estimated Fixed Cost
Return Requirement
Federal Income Taxes Other Taxes
Non-Fuel Expense
Allowed Rate of Return
Rate Base
Regulatory Process
Net Plant
Accumulated Depreciation
Plants
Losses
ELECTRICITY SALES 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
Sales to Other Retail & Wholesale Customers are Determined in Similar Ways.
CUSTOMER SUBMODEL
Number of Commercial Customers Dynamics
Number of Residential Customers Dynamics
Population in Utility Service Area Dynamics

FIGURE 2.2

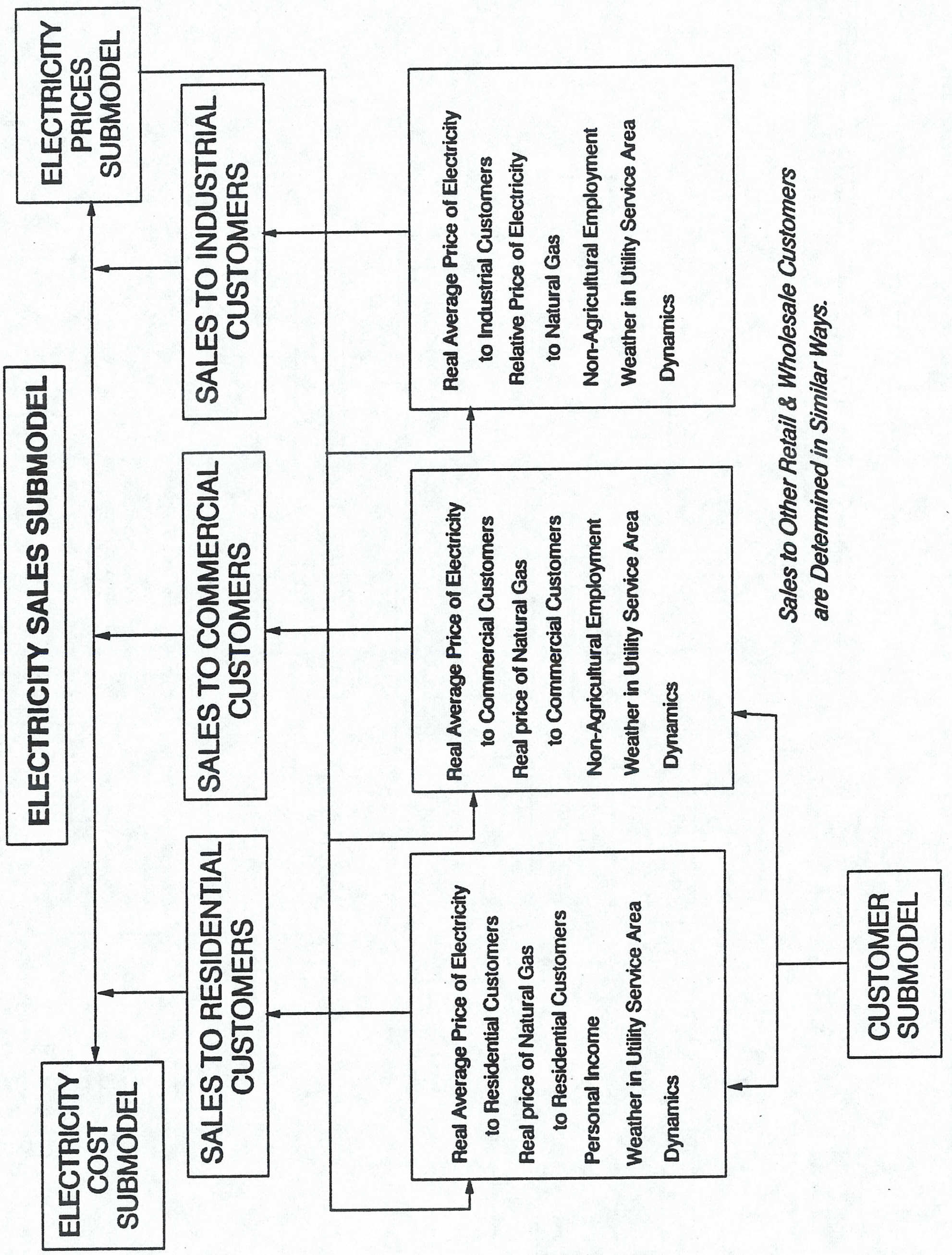
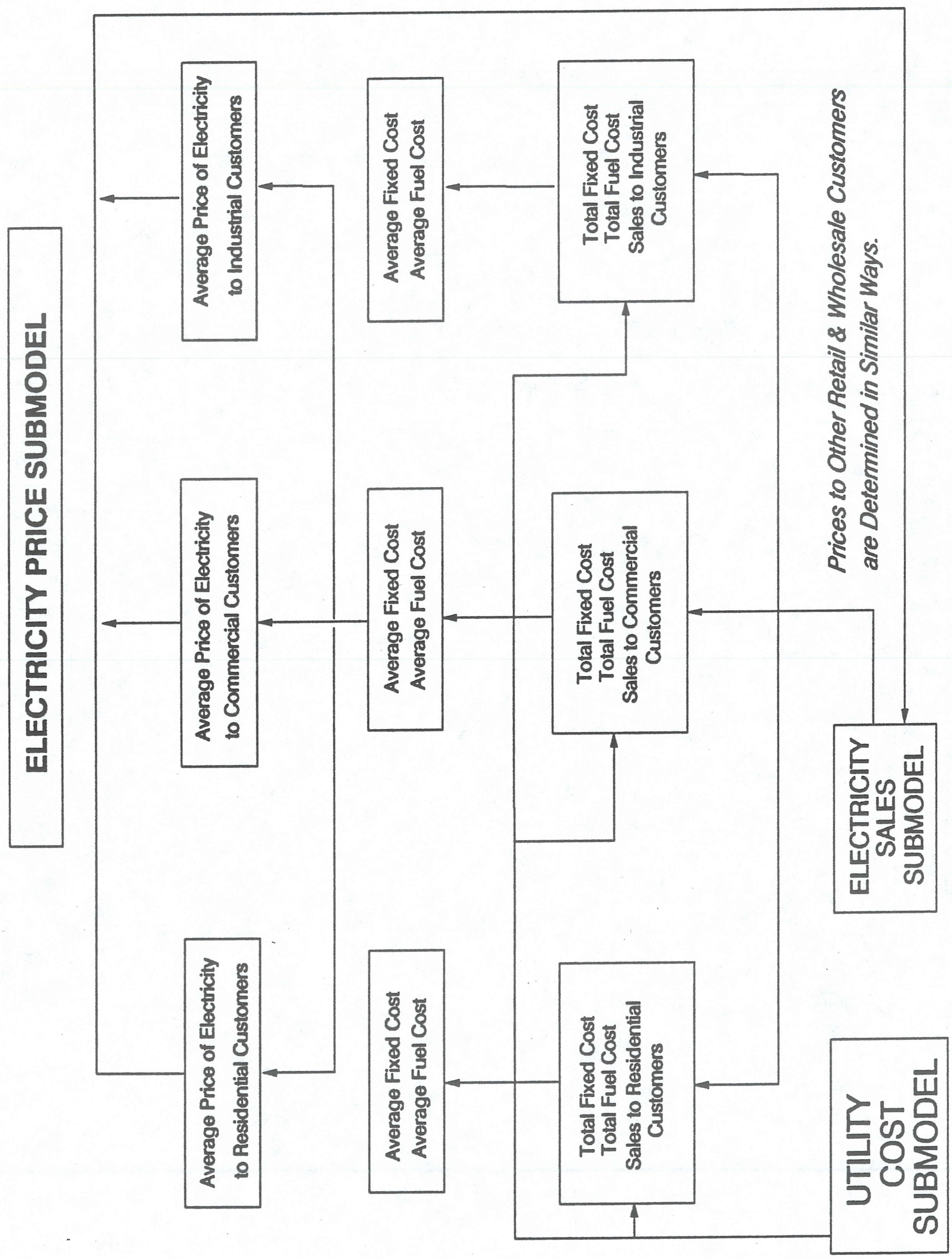

ELECTRICITY SALES SUBMODEL
ELECTRICITY PRICES SUBMODEL
ELECTRICITY COST SUBMODEL
SALES TO INDUSTRIAL CUSTOMERS
SALES TO COMMERCIAL CUSTOMERS
SALES TO RESIDENTIAL CUSTOMERS
Real Average Price of Electricity to Industrial Customers
Relative Price of Electricity to Natural Gas
Non-Agricultural Employment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

FIGURE 2.3



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

FIGURE 2.4

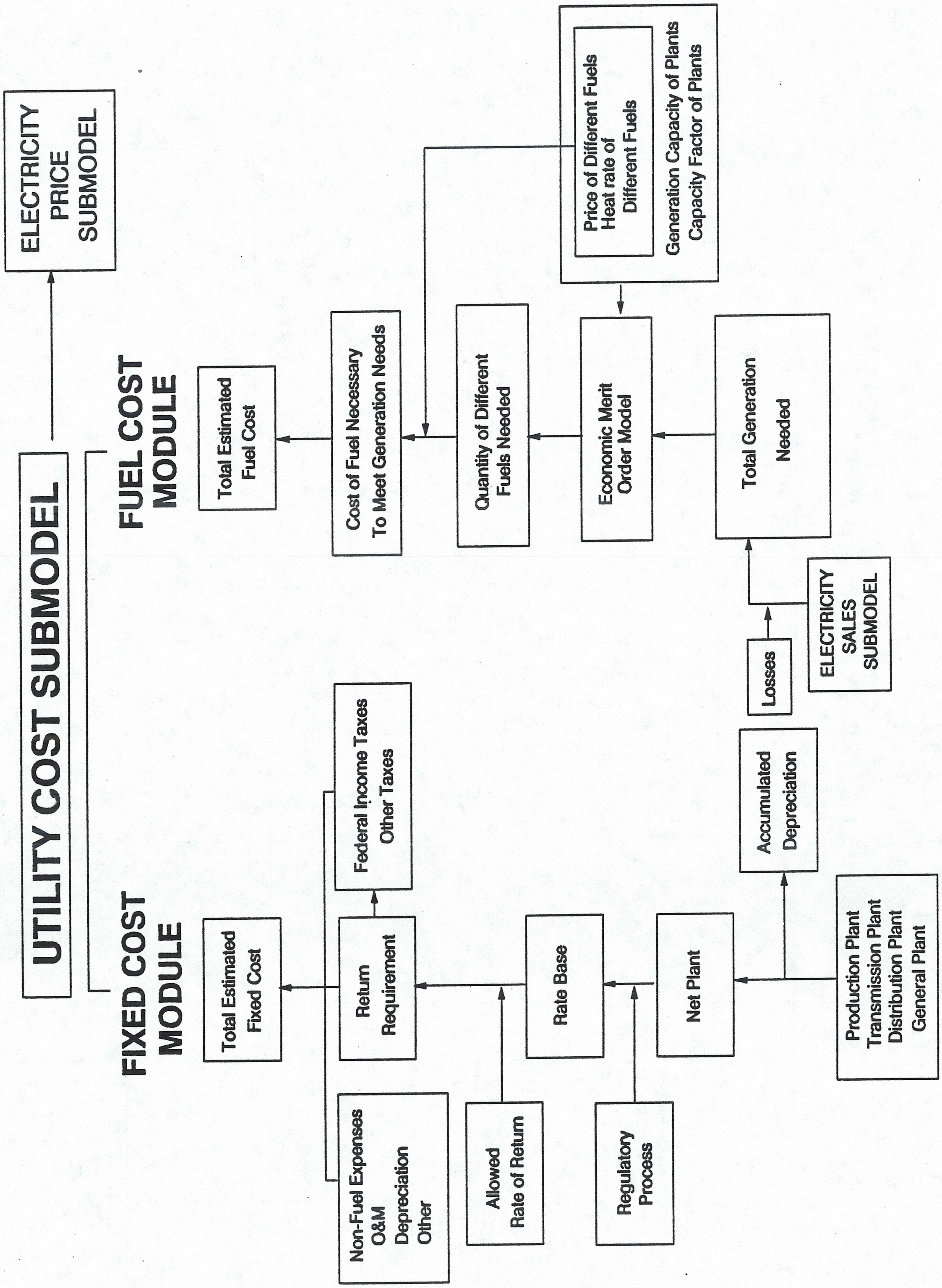
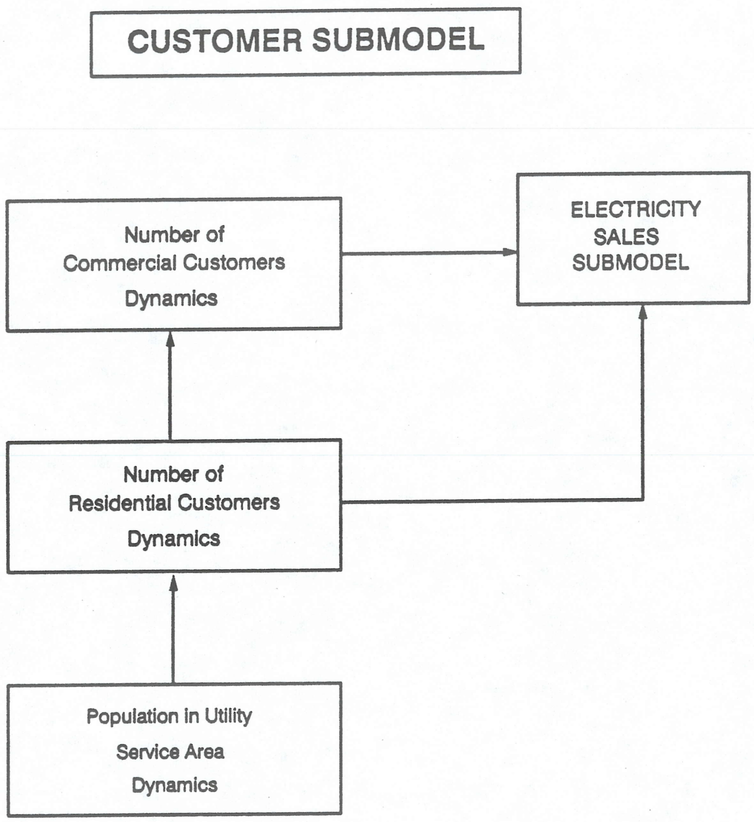

UTILITY COST SUBMODEL
ELECTRICITY PRICE SUBMODEL
FUEL COST MODULE
FIXED COST MODULE
Total Estimated Fuel Cost
Cost of Fuel Necessary To Meet Generation Needs
Quantity of Different Fuels Needed
Economic Merit Order Model
Total Generation Needed
Price of Different Fuels
Heat rate of Different Fuels
Generation Capacity of Plants
Capacity Factor of Plants
ELECTRICITY SALES SUBMODEL
Losses
Total Estimated Fixed Cost
Return Requirement
Federal Income Taxes
Other Taxes
Non-Fuel Expenses
O&M
Depreciation
Other
Rate Base
Allowed Rate of Return
Net Plant
Regulatory Process
Accumulated Depreciation
Production Plant
Transmission Plant
Distribution Plant
General Plant

FIGURE 2.5


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

CHAPTER THREE

DATABASE DEVELOPMENT

Introduction

The Commission Staff relies on different forecasting models to prepare projections of electricity consumption by rate classes and system peak demand for thirteen major electric utilities in Texas. To provide data input for these forecasting models, a computerized database containing over 7,000 data files is maintained by the PUCT staff. This chapter will discuss the data used in this project, its sources, and any transformations performed before the information is used in the forecasting models.

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 (annual, quarterly, and monthly, being the most common) to a comparable frequency
3. Developing reasonable projections of the factors affecting future electricity demand (exogenous variables)

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 each utility 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 utility responses to data requests by the PUCT, mainly through Load and

Capacity Resource Forecast filings. Historical economic and demographic data are obtained from a number of state and federal government agencies, as well as Data Resources, Inc.

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

Methodology of Aggregating County Level Economic Demographic Data

Since utility service areas rarely correspond to any political boundaries, a method of proportioning and aggregating county-level economic and demographic data is developed at the "utility planning region" level. Each utility planning region corresponds 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 is 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 a time consuming process. First, a set of maps is developed to illustrate the portion of each county in Texas served by a particular utility, including cooperatives. The initial maps are provided by the PUCT engineering staff. Second, a 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). Staff is in the process of updating this information. Third, the 17 cooperatives that purchase electricity from more than one utility are requested to provide the portion of each county in their service area served by a specific generating utility. In most cases, this information is derived from the cooperatives' transmission networks. Fourth, the original maps are redrawn 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 final task is to indicate the proportion of the population in each county contained in a given service area. Modifications are performed over time to reflect changes in utilities' service area boundaries.

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

Population

Source: Based on annual county-level data from Data Resources, Inc., the U.S. Bureau of Economic Analysis, Wharton Econometric Forecasting Associates, 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 of Persons)

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

Transformation to Quarterly:
Fitting spline curves

Personal Income

Source: Based on annual county-level data from Data Resources, Inc., Wharton Econometric Forecasting Associates, 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. (Millions of current dollars.)

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

Transformation to Quarterly:
Fitting spline curves

Employment

Source: Based on annual county-level data from Data Resources, Inc., Wharton Econometric Forecasting Associates, 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) in thousands.

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

Transformation to Quarterly:
Fitting spline curves

Price Indices

Source: Wharton Econometric Forecasting Associates

Series: Texas CPI.
Producers Price Index: finished goods,
industrial goods
GNP Deflator

Transformation to Quarterly:
Annual data used as quarterly estimates

Handy-Whitman
Cost Indices

Source: Wharton Econometric Forecasting Associates

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)

Transformation to Quarterly:
Fitting spline curves

Fuel Prices

Source: 1989 Load and Capacity Resource Forecast filing.
Monthly fuel reports filed with PUCT

Series: Average fuel cost by utility by fuel type (natural gas, nuclear, coal, lignite [Dollars per MMBTU], purchased power [Cents per kWH], etc.)

Transformation to Quarterly:
Fitting spline curves. (Second quarter data is considered the annual figure.)

Fuel Expenditure

Source: 1989 Load and Capacity Resource Forecast filing.
Monthly fuel reports filed with PUCT

Series: Total fuel expenditure by utility

Capacity

Source: 1989 Load and Capacity Resource Forecast filing

Series: Capacity for natural gas and capacity for other fuels by plant

Transformation to Quarterly:
Annual data used as quarterly estimates

Capacity Factor

Source: 1989 Load and Capacity Resource Forecast filing

Series: Capacity factor for natural gas and capacity for other fuels by plant

Transformation to Quarterly:
Annual data used as quarterly estimates

Heat Rate

Source: 1989 Load and Capacity Resource Forecast filing

Series: Heat rate for natural gas and heat rate for other fuels by plant

Transformation to Quarterly:
Annual data used as quarterly estimates

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: Utility responses to PUCT requests for data. 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 across utilities. Generally the information included total electric expenses (or operating expenses) and sales and revenues by rate class (residential, commercial, industrial, and other).

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 16-year averages.
Population, Employment, and Personal Income	The projections of these Service Area economic data are generated by the PUCT Economic Analysis Section. Table 3.1 provides a summary of the growth rates (in percentage terms) for these variables between 1988 and 1999.
Price Indices	The projected indices are based on the WEFA Fall 1989 Forecast.
Handy-Whitman Cost Indices	Obtained from WEFA's third quarter 1989 forecast.
Price of Natural Gas to Residential, Commercial, and Industrial Customers	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 2004 for each of the thirteen major utilities discussed throughout this report. The average compound growth rates for the forecast period for residential, commercial, and industrial customers are 5.22, 5.11, and 5.40 percent, respectively.
Fuel Price	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. These projected fuel costs are found in Volume I, Chapter Two of this report.
Capacity Data	Capacity data are provided by the Engineering Section of the Electric Division at the PUCT and based on data in the ten-year load forecasts filed by the state's generating electric utilities, December 1989.

Heat Rate Heat rate data provided by the Engineering Section of the Electric Division at the PUCT and are based on data in Monthly fuel reports filed with the PUCT.

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.

Operating Data Sales, average prices, and fuel costs are projected within the econometric models. That is, they are endogenous to the models.

TABLE 3.1

STAFF PROJECTED GROWTH RATES

SERVICE AREA ECONOMIC/DEMOGRAPHIC VARIABLES
1988/1999
(Percent)

Utility Service Area	Total Population	Non Agricultural Employment	Nominal Personal Income	Real Personal Income
TU ELECTRIC	1.47	1.88	7.40	2.12
HL&P	1.52	2.29	8.23	2.90
GSU-TX	0.06	1.14	5.86	0.66
CPL	1.65	2.18	7.55	2.27
CPS	1.31	1.80	6.96	1.70
SPS-TX	0.94	1.64	7.22	1.94
SWEPCO-TX	0.83	1.34	6.83	1.58
LCRA	1.59	2.19	7.91	2.61
COA	2.49	2.39	7.99	2.68
WTU	1.27	1.72	7.23	1.95
EPE-TX	1.33	1.99	7.31	2.03
TNP-PANH	0.91	1.47	7.23	1.95
TNP-NORTH	1.46	1.90	7.40	2.12
TNP-CENT	1.49	1.93	7.44	2.16
TNP-SOUTH	0.73	1.37	7.08	1.81
TNP-WEST	1.60	1.77	7.19	1.92
BEPC	2.19	2.58	8.03	2.72
TOTAL-MSA	1.47	2.00	7.58	2.29
TEXAS				
LEVEL (1988)	16,837,000	6,646,900	245,650	259,562
LEVEL (1999)	19,625,000	8,066,400	537,170	326,044
GROWTH RATE	1.40	1.78	7.38	2.10
EPE-NTX	1.25	1.63	7.35	2.08
GSU-NTX	0.65	1.19	6.38	1.14
SWEPCO-NTX	0.15	0.79	5.89	0.68
SPS-NTX	0.94	1.64	7.22	1.94

Sources:
Texas Economic Forecast: M. Ray Perryman, Ph.D.; May, 1990
Wharton Econometric Forecasting Associates, Fall 1989 Forecast
U.S. Department of Commerce, Bureau of the Census
U.S. Bureau of Economic Analysis
Oklahoma Employment Security Commission
Arkansas Employment Security Commission
New Mexico Department of Labor
Louisiana Department of Labor
Kansas Department of Labor

<u>CHAPTER FOUR</u>

MODELING AND FORECASTING PROCEDURES

A major change in procedure for the 1990 **Long-Term Peak Demand and Capacity Resource Forecast for Texas** is the incorporation of the data base and model development in a personal computer environment using Time Series Processor (TSP): version 4.1C (1988). TSP, created in 1967 by Bronwyn H. Hall for TSP International, provides data manipulation, regression, forecasting, and advanced econometric techniques on mainframe and smaller computer frameworks. In the past, software used for the models, database, graphics, and many of the data transformations were written mainly in TROLL, a mainframe statistical software package developed at the Massachusetts Institute of Technology.

An advantage of TSP is that it is able to read information directly from worksheets. This is convenient because data, in the form of LOTUS 123 worksheets, can be directly read into TSP and the results can easily be developed into LOTUS graphs. A disadvantage of TSP is that it is unable to convert data to lower frequencies. Typically, annual data needs to be converted into quarterly data. Under these circumstances, (PC) SAS is used to expand data from lower frequencies. The method used fits spline curves to the input values.

Sales Model Estimation Procedure

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 method, two-stage least squares (2SLS), is used in producing the final results.

In TSP, 2SLS is treated as an instrumental variables technique. The modeler is required to choose the instruments used in estimation. 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 at minimum variance and are therefore, not consistent. As a result, the estimated coefficients will not be as precisely determined as they might be. A modified 2SLS procedure is used when deemed appropriate. This method employs 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. Gauss-Seidel 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, developed by ICF, Incorporated for EPRI, is a structural model that applies hourly load shapes to class (i.e , Residential, Commercial, Industrial) sales forecasts in order to obtain hourly demand projections. The hourly demands are summed across classes and added to hourly losses in order 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 and in information contained in the utility Load and Capacity Resource filings.

The **Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988** represens the first application of HELM for developing the official PUCT peak demand forecast. This approach is a significant improvement over previous efforts in which constant load factors were applied to class sales forecasts. The use of HELM also allows more flexibility in load forecasting because various weather scenarios, load management programs, and changes in customer mix and consumption patterns may be explicitly modeled.

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APPENDIX A

MODEL ESTIMATION RESULTS

A-1 TEXAS UTILITIES ELECTRIC COMPANY

MODEL: TUEC

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCTU	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AQTTU	-	AVERAGE FUEL AND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CAPINST1	-	INSTRUMENT FOR CAPTU
CAPTU	-	COMMERCIAL AVERAGE PRICE:'000 OF $ PER MWH
CSTU	-	COMMERCIAL SALES: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
GRPPNU	-	GENERATION REQUIREMENTS FROM PURCAHSED POWER FROM NON-UTILTY SOURCES
GENRTU	-	GENERATION REQUIREMENTS:MWH
IAPINST	-	INSTRUMENT FOR IAPTU
IAPTU	-	INDUSTRIAL AVERAGE PRICE:'000 OF $ PER MWH
ISTU	-	INDUSTRIAL SALES:MWH
OAPTU	-	OTHER SALES AVERAGE PRICE:000'S OF $ PER MWH
OSTU	-	OTHER 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
PLNTIC	-	CONDITIONAL VARIABLE
PLNTJC	-	CONDITIONAL VARIABLE
PLNTKC	-	CONDITIONAL VARIABLE
PLNTLC	-	CONDITIONAL VARIABLE
PLNTMC	-	CONDITIONAL VARIABLE
PPNUC	-	CONDITIONAL VARIABLE
QTTU	-	TOTAL FUEL EXPENSE ESTIMATE:000'S OF DOLLARS
RAPINST	-	INSTRUMENT FOR RAPTU
RAPTU	-	RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH
RSTU	-	RESIDENTIAL SALES:MWH
TVCTU	-	TOTAL FUEL EXPENSE AND PURCHASED POWER REQUIREMENTS:000'S OF DOLLARS
TSTU	-	TOTAL SYSTEM SALES:MWH
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 $
VCPPNU	-	COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $

WAPINST	-	INSTRUMENT FOR WAPTU
WAPTU	-	WHOLESALE AVERAGE PRICE:000'S OF $ PER MWH
WSTU	-	WHOLESALE SALES:MWH

EXOGENOUS:

C	-	CONSTANT TERM
CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEVCEE DAYS
CCTU	-	NUMBER OF COMMERCIAL CUSTOMERS
CDDTU	-	COOLING DEGREE DAYS:NUMBER OF DAYS
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
D1	-	DUMMY FOR INDUSTRIAL PRICE EQUATION
D3	-	DUMMY FOR OTHER SALES 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
GCPPNU	-	GENERATION CAPABILITY OF PURCAHSED POWER FROM NON-UTILITY SOURCES
GNPD	-	GNP DEFLATOR
HDDTU	-	HEATING DEGREE DAYS:NUMBER OF DAYS
ILFCSTU	-	LOSS FACTOR: COMMERCIAL SALES;
ILFISTU	-	LOSS FACTOR: INDUSTRIAL SALES;
ILFOSTU	-	LOSS FACTOR: OTHER SALES;
ILFRSTU	-	LOSS FACTOR: RESIDENTIAL SALES;
ILFWSTU	-	LOSS FACTOR: WHOLESALE SALES;

MATFCFCTU	-	FOUR QUARTER MOVING SUM OF TOTAL FIXED COSTS:000'S OF $
NAGTU	-	NON-AGRICULTURAL EMPLOYMENT:000'S OF PERSONS
PNGCOM	-	PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS: $ PER MCF
POPTU	-	POPULATION IN TU SERVICE AREA: OOO'S OF PERSONS
PPII	-	PRODUCERS PRICE INDEX FOR INDUSTRIAL GOODS
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RCTU	-	RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
RHDDINST	-	INSTRUMENT FOR RESIDENTIAL HEATING DEGREE DAYS
RPITU	-	REAL PERSONAL INCOME (BILLIONS OF DOLLARS)
RPNGIND	-	REAL PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS
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 $
UFCPPNU	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH

IDENTITIES

RAPINST	=	(RAPTU/CPITX)*RCTU
CAPINST1	=	(CAPTU/PNGCOM)*CCTU
IAPINST	=	(IAPTU/PPII)
WAPINST	=	WAPTU/GNPD
OAPINST	=	OAPTU/GNPD
TSTU	=	RSTU+CSTU+ISTU+WSTU+OSTU
AQTTU	=	QTTU/TSTU
AFCTU	=	MATFCTU/(TSTU+TSTU(-1)+TSTU(-2)+TSTU(-3))
GENRTU	=	RSTU*ILFRSTU+CSTU*ILFCSTU+ISTU*ILFISTU+ WSTU*ILFWSTU+OSTU*ILFOSTU
PPNUC	=	GENRTU-GCPPNU
PLNTAC	=	PPNUC-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
GRPPNU	=	(PPNUC>0)*GCPPNU+(PPNUC<0)*GENRTU
VCPPNU	=	GRPPNU*UFCPPNU
GRPLNTA	=	(PPNUC>0)*((PLNTAC>0)*GCPLNTA+(PLNTAC<0)*PPNUC)
VCPLNTA	=	GRPLNTA*UFCPLNTA;
GRPLNTB	=	(PPNUC>0)*(PLNTAC>0)*((PLNTBC>0)*GCPLNTB+(PLNTBC<0)*PLNTAC)
VCPLNTB	=	GRPLNTB*UFCPLNTB
GRPLNTC	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)* ((PLNTCC>0)*GCPLNTC+(PLNTCC<0)*PLNTBC)
VCPLNTC	=	GRPLNTC*UFCPLNTC

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GRPLNTD   =  (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*
             ((PLNTDC>0)*GCPLNTD+(PLNTDC<0)*PLNTCC)

VCPLNTD   =  GRPLNTD*UFCPLNTD

GRPLNTE   =  (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
             ((PLNTEC>0)*GCPLNTE+(PLNTEC<0)*PLNTDC)

VCPLNTE   =  GRPLNTE*UFCPLNTE

GRPLNTF   =  (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
             (PLNTEC>0)*((PLNTFC>0)*GCPLNTF+(PLNTFC<0)*PLNTEC)

VCPLNTF   =  GRPLNTF*UFCPLNTF

GRPLNTG   =  (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
             (PLNTEC>0)*((PLNTFC>0)*((PLNTGC>0)*GCPLNTG+(PLNTGC<0)*PLNTFC)

VCPLNTG   =  GRPLNTG*UFCPLNTG

GRPLNTH   =  (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*
             (PLNTEC>0)*(PLNTFC>0)*(PLNTGC>0)*((PLNTHC>0)*GCPLNTH+
             (PLNTHC<0)*PLNTGC)

VCPLNTH   =  GRPLNTH*UFCPLNTH;

GRPLNTI   =  (PPNUC>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

GRPLNTJ   =  (PPNUC>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

GRPLNTK   =  (PPNUC>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

GRPLNTL   =  (PPNUC>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

GRPLNTM   =  (PPNUC>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;

GRPLNTN   =  (PPNUC>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)*PLNTMC

VCPLNTN   =  GRPLNTN*UFCPLNTN
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TVCTU = VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+VCPLNTE+VCPLNTF+
VCPLNTG+VCPLNTH+VCPLNTI+VCPLNTJ+VCPLNTK+VCPLNTL+
VCPLNTM+VCPLNTN+VCPPNU

EQUATION ESTIMATES

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 1: RESIDENTIAL SALES

RSTU = a0 + a1*RAPINST + a2*RPITU + a3*RCDDINST + a4*RHDDINST

FINAL VALUE OF RHO	=	-0.295151
STANDARD ERROR OF RHO	=	0.155850
T-STATISTIC FOR RHO	=	-0.89382
SUM OF SQUARED RESIDUALS	=	0.578563E+13
STANDARD ERROR OF THE REGRESSION	=	366810.
MEAN OF DEPENDENT VARIABLE	=	0.711318E+07
STANDARD DEVIATION	=	0.168286E+07
R^2	=	0.956602
ADJUSTED R^2	=	0.952565
DURBIN-WATSON STATISTIC	=	1.9425
LOG OF LIKELIHOOD FUNCTION	=	-680.519
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.14581E+07	0.33464E+06	-4.3572
RAPINST	-26.016	12.506	-2.0803
RPITU(-4)	0.64147E+06	0.10287E+06	6.2357
RCDDINST	0.25263E-02	0.14098E-03	17.920
RHDDINST	0.17248E-02	0.14261E-03	12.095

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 2: COMMERCIAL SALES

CSTU = b0 + b1*CAPINST1 + b2*NAGTU(-4) + b3*CCDDINST + b4*CHDDINST

FINAL VALUE OF RHO	=	0.688512
STANDARD ERROR OF RHO	=	0.110979
T-STATISTIC FOR RHO	=	6.20400
SUM OF SQUARED RESIDUALS	=	0.161948E+13
STANDARD ERROR OF THE REGRESSION	=	194068.
MEAN OF DEPENDENT VARIABLE	=	0.149688E+07
STANDARD DEVIATION	=	795049.
R^2	=	0.945489
ADJUSTED R^2	=	0.940419
DURBIN-WATSON STATISTIC	=	0.8906
LOG OF LIKELIHOOD FUNCTION	=	-650.237
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.31402E+07	0.70982E+06	-4.4240
CAPINST1	-430.18	234.20	-1.8368
NAGTU(-4)	3632.6	379.59	9.5699
CCDDINST	0.65264E-02	0.31185E-03	20.928
CHDDINST	0.26014E-02	0.33047E-03	7.8718

2SLS ESTIMATION USING COCHRANE-ORCUTT ITERATIVE TECHNIQUE

EQUATION 3: INDUSTRIAL SALES

ISTU = c0 + c1*ISTU(-4) + c2*IAPINST + c3*RPINGIND + c4*NAGTU + c5*CDDTU

FINAL VALUE OF RHO	=	0.417418
STANDARD ERROR OF RHO	=	0.136994
T-STATISTIC FOR RHO	=	3.04698
SUM OF SQUARED RESIDUALS	=	0.905730E+12

STANDARD ERROR OF THE REGRESSION	=	154386.
MEAN OF DEPENDENT VARIABLE	=	0.289003E+07
STANDARD DEVIATION	=	340734.
R^2	=	0.818661
ADJUSTED R^2	=	0.794801
DURBIN-WATSON STATISTIC	=	1.7670
LOG OF LIKELIHOOD FUNCTION	=	-584.885
NUMBER OF OBSERVATIONS	=	44

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.30980E+06	0.54221E+06	-0.57135
ISTU(-4)	0.23163	0.15683	1.4769
IAPINST	-0.36204E+08	0.11145E+08	-3.2483
RPNGIND	0.16279E+06	99810.	1.6310
NAGTU	2170.7	490.92	4.4217
CDDTU	172.68	46.799	3.6899

2SLS ESTIMATION

<u>EQUATION 4: WHOLESALE SALES</u>

WSTU = dO + d1*WAPINST + d2*NAGTU + d3*CDDTU + d4*HDDTU

SUM OF SQUARED RESIDUALS	=	0.158870E+12
STANDARD ERROR OF THE REGRESSION	=	60783.6
MEAN OF DEPENDENT VARIABLE	=	0.123272E+07
STANDARD DEVIATION	=	247631.
R^2	=	0.944879
ADJUSTED R^2	=	0.939752
DURBIN-WATSON STATISTIC	=	2.2156
F-STATISTIC(4,43)	=	184.268
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.94356E+06	0.11202E+06	-8.4229
WAPINST	-0.51726E+07	0.20820E+07	-2.4844
NAGTU	833.62	44.162	18.876
CDDTU	529.65	28.992	18.269
HDDTU	324.15	29.624	10.942

2SLS ESTIMATION

EQUATION 5: OTHER SALES

OSTU = e0 + e1*OAPINST + e2*POPTU + e3*CDDTU + e4*D3

SUM OF SQUARED RESIDUALS	=	0.391784E+11
STANDARD ERROR OF THE REGRESSION	=	30184.9
MEAN OF DEPENDENT VARIABLE	=	517536.
STANDARD DEVIATION	=	104349.
R^2	=	0.923451
ADJUSTED R^2	=	0.916330
DURBIN-WATSON STATISTIC	=	1.7858
F-STATISTIC(4,43)	=	129.672
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.16392E+06	96299.	-1.7022
OAPINST	-0.39393E+07	0.12518E+07	-3.1470
POPTU	166.81	29.512	5.6525
CDDTU	52.376	7.6267	6.8675
D3	66763.	23871.	2.7968

2SLS ESTIMATION

EQUATION 6: RESIDENTIAL PRICE

RAPTU = f0 + f1*AQTTU + f2*AFCTU

SUM OF SQUARED RESIDUALS	=	0.870511E-03
STANDARD ERROR OF THE REGRESSION	=	0.439826E-02
MEAN OF DEPENDENT VARIABLE	=	0.571189E-01
STANDARD DEVIATION	=	0.121865E-01
R^2	=	0.875288
ADJUSTED R^2	=	0.869746
DURBIN-WATSON STATISTIC	=	2.0660
F-STATISTIC(2,5)	=	157.912
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.91357E-02	0.36410E-02	2.5091
AQTTU	1.5413	0.20424	7.5466
AFCTU	0.68219	0.25138	2.7138

2SLS ESTIMATION

EQUATION 7: COMMERCIAL PRICE

CAPTU = g0 + g1*AQTTU + g2*AFCTU

SUM OF SQUARED RESIDUALS	=	0.282978E-03
STANDARD ERROR OF THE REGRESSION	=	0.250767E-02
MEAN OF DEPENDENT VARIABLE	=	0.504781E-01
STANDARD DEVIATION	=	0.866286E-02

R^2	=	0.919777
ADJUSTED R^2	=	0.916211
DURBIN-WATSON STATISTIC	=	2.1574
F-STATISTIC(2,45)	=	257.946
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.16964E-01	0.20759E-02	8.1716
AQTTU	1.2322	0.11645	10.581
AFCTU	0.34792	0.14332	2.4275

2SLS ESTIMATION

<u>EQUATION 8: INDUSTRIAL PRICE</u>

IAPTU = h0 + h1*AQTTU + h2*AFCTU + h3*D1

SUM OF SQUARED RESIDUALS	=	0.179410E-03
STANDARD ERROR OF THE REGRESSION	=	0.201928E-02
MEAN OF DEPENDENT VARIABLE	=	0.365654E-01
STANDARD DEVIATION	=	0.760064E-02
R^2	=	0.933928
ADJUSTED R^2	=	0.929423
DURBIN-WATSON STATISTIC	=	2.0955
F-STATISTIC(3,44)	=	207.297
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.10721E-02	0.27821E-02	-0.38536
AQTTU	0.67615	0.14775	4.5764
AFCTU	1.0519	0.23212	4.5317
D1	-0.60131E-02	0.12905E-02	-4.6594

2SLS ESTIMATION

EQUATION 9: WHOLESALE PRICE

WAPTU = i0 + i1*AQTTU + i2*AFCTU

SUM OF SQUARED RESIDUALS	=	0.328895E-03
STANDARD ERROR OF THE REGRESSION	=	0.270348E-02
MEAN OF DEPENDENT VARIABLE	=	0.369773E-01
STANDARD DEVIATION	=	0.828078E-02
R^2	=	0.897949
ADJUSTED R^2	=	0.893414
DURBIN-WATSON STATISTIC	=	1.9494
F-STATISTIC(2,45)	=	197.978
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.33153E-02	0.22380E-02	1.4814
AQTTU	1.0043	0.12554	7.9997
AFCTU	0.54221	0.15452	3.5091

2SLS ESTIMATION

EQUATION 10: OTHER PRICE

OAPTU = j0 + j1*AQTTU + j2*AFCTU

SUM OF SQUARED RESIDUALS	=	0.284908E-03
STANDARD ERROR OF THE REGRESSION	=	0.251621E-02
MEAN OF DEPENDENT VARIABLE	=	0.511625E-01
STANDARD DEVIATION	=	0.113844E-01

R^2	=	0.953239
ADJUSTED R^2	=	0.951160
DURBIN-WATSON STATISTIC	=	2.0196
F-STATISTIC(2,45)	=	458.559
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.14081E-02	0.20830E-02	0.67599
AQTTU	1.2710	0.11685	10.878
AFCTU	0.97770	0.14381	6.7985

2SLS ESTIMATION

<u>EQUATION 11: TOTAL FUEL EXPENSE</u>

QTTU = k0 + k1*TVCTU

SUM OF SQUARED RESIDUALS	=	0.911446E+11
STANDARD ERROR OF THE REGRESSION	=	44513.0
MEAN OF DEPENDENT VARIABLE	=	347582.
STANDARD DEVIATION	=	131792.
R^2	=	0.888540
ADJUSTED R^2	=	0.886117
DURBIN-WATSON STATISTIC	=	1.8292
F-STATISTIC(1,46)	=	366.006
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	17571.	18422.	0.95381
TVCTU	0.98340	0.51450E-01	19.114

A-2 HOUSTON LIGHTING & POWER COMPANY

MODEL: HL&P

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCHLP	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AQTHLP	-	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
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
GRPPNU	-	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
PPNUC	-	CONDITIONAL VARIABLE
QTHLP	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST ESTIMATE:000'S OF $
RAPHLP	-	RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH

RAPINST	-	INSTRUMENT FOR RAPHLP
RSHLP	-	RESIDENTIAL SALES:MWH
TSHLP	-	TOTAL SYSTEM SALES:MWH
TVCHLP	-	TOTAL FUEL AND PURCHASED POWER EXPENSE REQUIREMENTS: 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 $
VCPPNU	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $

EXOGENOUS:

APDUM	-	DUMMY IN AVERAGE PRICE EQUATION
C	-	CONSTANT TERM
CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CCHLP	-	COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
CDDHLP	-	COOLING DEGREE DAYS:NUMBER OF DAYS
CSDUM	-	DUMMY IN COMMERCIAL SALES EQUATION
GCPPNU	-	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
ILFCSHLP	-	LOSS FACTOR: COMMERCIAL SALES
ILFISHLP	-	LOSS FACTOR: INDUSTRIAL SALES
ILFOSHLP	-	LOSS FACTOR: OTHER SALES
ILFRSHLP	-	LOSS FACTOR: RESIDENTIAL SALES
ILFWSHLP	-	LOSS FACTOR: WHOLESALE SALES
ISDUM	-	DUMMY FOR INDUSTRIAL SALES
MATFCHLP	-	FOUR QUARTER MOVING SUM TOTAL FIXED COSTS:000'S OF DOLLARS

NAGHLP	-	NON-AGRICULTURAL EMPLOYMENT IN HLP SERVICE AREA: 000'S OF PERSONS
OSHLP	-	OTHER SALES:MWH
PNGCOM	-	PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS: $ PER MCF
PNGIND	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS: $ PER MCF
PNGRES	-	PRICE OF NATURAL GAS TO RESIDENTIAL 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)
UFCNG	-	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 $
UFCPPNU	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH
WSHLP	-	WHOLESALE SALES:MWH

IDENTITIES

RAPINST	=	(RAPHLP(-3)/PNGRES(-3))*RCHLP
CAPINST	=	(CAPHLP(-4)/PNGCOM(-4))*CCHLP
IAPINST	=	IAPHLP/PNGIND
TSHLP	=	RSHLP+CSHLP+ISHLP+WSHLP+OSHLP
AQTHLP	=	QTHLP/TSHLP
AFCHLP	=	MATFCHLP/(TSHLP+TSHLP(-1)+TSHLP(-2)+TSHLP(-3))

GENRHLP = RSHLP*ILFRSHLP+CSHLP*ILFCSHLP+ISHLP*ILFISHLP+WSHLP*ILFWSHLP+OSHLP*ILFOSHLP

PPNUC = GENRHLP-GCPPNU

PLNTAC = PPNUC-GCPLNTA

PLNTBC = PLNTAC-GCPLNTB

PLNTCC = PLNTBC-GCPLNTC

PLNTDC = PLNTCC-GCPLNTD

PLNTEC = PLNTDC-GCPLNTE

PLNTFC = PLNTEC-GCPLNTF

GRPPNU = (PPNUC>0)*GCPPNU+(PPNUC<0)*GENRHLP

VCPPNU = GRPPNU*UFCPPNU

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

VCPLNTA = GRPLNTA*UFCPLNTA

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

VCPLNTB = GRPLNTB*UFCPLNTB

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

VCPLNTC = GRPLNTC*UFCPLNTC

GRPLNTD = (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*((PLNTDC>0)*GCPLNTD+(PLNTDC<0)*PLNTCC)

VCPLNTD = GRPLNTD*UFCPLNTD

GRPLNTE = (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*((PLNTEC>0)*GCPLNTE+(PLNTEC<0)*PLNTDC)

VCPLNTE = GRPLNTE*UFCPLNTE

GRPLNTF = (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*((PLNTFC>0)*GCPLNTF+(PLNTFC<0)*PLNTEC)

VCPLNTF = GRPLNTF*UFCPLNTF

GRNG = (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)*(PLNTEC>0)*(PLNTFC>0)*PLNTFC

VCNG = GRNG*UFCNG

TVCHLP = VCPPNU+VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+VCPLNTE+VCPLNTF+VCNG

EQUATION ESTIMATES

2SLS ESTIMATION USING COCHRANE-ORCUTT ITERATIVE TECHNIQUE

EQUATION 1: RESIDENTIAL SALES

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

FINAL VALUE OF RHO	=	0.203500
STANDARD ERROR OF RHO	=	0.144357
T-STATISTIC FOR RHO	=	1.40971
SUM OF SQUARED RESIDUALS	=	0.193303E+13
STANDARD ERROR OF THE REGRESSION	=	219831.
MEAN OF DEPENDENT VARIABLE	=	0.277026E+07
STANDARD DEVIATION	=	0.108738E+07
R^2	=	0.963692
ADJUSTED R^2	=	0.959153
DURBIN-WATSON STATISTIC	=	1.8633
LOG OF LIKELIHOOD FUNCTION	=	-627.885
NUMBER OF OBSERVATIONS	=	46

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.59484E+06	0.81903E+06	- 0.72627
RSHLP(-4)	0.71349	0.82688E-01	8.6286
RAPINST	-28.792	17.990	-1.6004
RPIHLP	0.28335E+06	0.22538E+06	1.2572
RCDDINST	0.79319E-03	0.22851E-03	3.4712
RHDDINST	0.67463E-03	0.23635E-03	2.8544

2SLS ESTIMATION USING COCHRANE-ORCUTT ITERATIVE TECHNIQUE

EQUATION 2: COMMERCIAL SALES

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

FINAL VALUE OF RHO	=	0.278495
STANDARD ERROR OF RHO	=	0.141609
T-STATISTIC FOR RHO	=	1.96665
SUM OF SQUARED RESIDUALS	=	0.260385E+12
STANDARD ERROR OF THE REGRESSION	=	80682.2
MEAN OF DEPENDENT VARIABLE	=	0.191052E+07
STANDARD DEVIATION	=	350708.
R^2	=	0.953140
ADJUSTED R^2	=	0.947283
DURBIN-WATSON STATISTIC	=	1.9738
LOG OF LIKELIHOOD FUNCTION	=	-581.777
NUMBER OF OBSERVATIONS	=	46

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.53941E+06	0.38474E+06	-1.4020
CSHLP(-4)	0.91176	0.69696E-01	13.082
CAPINST	-71.421	51.107	-1.3975
NAGHLP	638.91	253.32	2.5221
CSDUM	-0.18653E+0	57376.	-3.2511
CCDDINST	0.35914E-03	0.24243E-03	1.4814

2SLS ESTIMATION USING COCHRANE-ORCUTT ITERATIVE TECHNIQUE

EQUATION 3: INDUSTRIAL SALES

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

FINAL VALUE OF RHO	=	-0.332208
STANDARD ERROR OF RHO	=	0.139068
T-STATISTIC FOR RHO	=	-2.38881
SUM OF SQUARED RESIDUALS	=	0.286616E+13
STANDARD ERROR OF THE REGRESSION	=	267682.
MEAN OF DEPENDENT VARIABLE	=	0.958150E+07
STANDARD DEVIATION	=	562751.
R^2	=	0.798988
ADJUSTED R^2	=	0.773862
DURBIN-WATSON STATISTIC	=	2.1416
LOG OF LIKELIHOOD FUNCTION	=	-636.944
NUMBER OF OBSERVATIONS	=	46

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.35438E+07	0.76278E+06	4.6460
ISHLP(-1)	0.26972	0.10163	2.6541
IAPINST	-0.78329E+08	0.20608E+08	-3.8008
NAGHLP	1532.8	531.52	2.8839
CDDHLP	483.72	68.383	7.0737
ISDUM	-0.51323E+06	91099.	-5.6337

2SLS ESTIMATION

EQUATION 4: RESIDENTIAL AVERAGE PRICE

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

SUM OF SQUARED RESIDUALS	=	0.148276E-02
STANDARD ERROR OF THE REGRESSION	=	0.580510E-02
MEAN OF DEPENDENT VARIABLE	=	0.669911E-01
STANDARD DEVIATION	=	0.174359E-01

R^2	=	0.896335
ADJUSTED R^2	=	0.889266
DURBIN-WATSON STATISTIC	=	2.2085
F-STATISTIC	=	126.668
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.20685E-02	0.36554E-02	- 0.56588
AQTHLP	1.0868	0.15361	7.0748
AFCHLP	1.6621	0.21224	7.8310
APDUM	-0.79486E-02	0.34678E-02	-2.2921

2SLS ESTIMATION

EQUATION 5: COMMERCIAL AVERAGE PRICE

CAPHLP = e0 + e1*AQTHLP + e2*AFHLP + e3*APDUM

SUM OF SQUARED RESIDUALS	=	0.792988E-03
STANDARD ERROR OF THE REGRESSION	=	0.424529E-02
MEAN OF DEPENDENT VARIABLE	=	0.598480E-01
STANDARD DEVIATION	=	0.137153E-01
R^2	=	0.910432
ADJUSTED R^2	=	0.904325
DURBIN-WATSON STATISTIC	=	2.3197
F-STATISTIC	=	148.855
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.47014E-02	0.26732E-02	1.7587
AQTHLP	1.0106	0.11233	8.9965
AFCHLP	1.1843	0.15521	7.6300
APDUM	-0.72801E-02	0.25360E-02	-2.8707

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 6: INDUSTRIAL AVERAGE PRICE

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

FINAL VALUE OF RHO	=	-0.243664
STANDARD ERROR OF RHO	=	0.146617
T-STATISTIC FOR RHO	=	-1.66190
SUM OF SQUARED RESIDUALS	=	0.586003E-03
STANDARD ERROR OF THE REGRESSION	=	0.369161E-02
MEAN OF DEPENDENT VARIABLE	=	0.497424E-01
STANDARD DEVIATION	=	0.124369E-01
R^2	=	0.917649
ADJUSTED R^2	=	0.911903
DURBIN-WATSON STATISTIC	=	2.2551
LOG OF LIKELIHOOD FUNCTION	=	198.649
NUMBER OF OBSERVATIONS	=	47

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.21788E-02	0.20103E-02	1.0838
AQTHLP	1.0798	0.85007E-01	12.702
AFCHLP	0.36872	0.11726	3.1443
APDUM	-0.39200E-02	0.19457E-02	-2.0147

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 7: TOTAL FUEL EXPENSE & PURCHASED POWER COST

QTHLP = g0 + g1*TVHLP

FINAL VALUE OF RHO	=	0.348223
STANDARD ERROR OF RHO	=	0.137905

T-STATISTIC FOR RHO	=	2.52508
SUM OF SQUARED RESIDUALS	=	0.603821E+11
STANDARD ERROR OF THE REGRESSION	=	36630.9
MEAN OF DEPENDENT VARIABLE	=	254227.
STANDARD DEVIATION	=	91106.5
R^2	=	0.841857
ADJUSTED R^2	=	0.838342
DURBIN-WATSON STATISTIC	=	1.9172
LOG OF LIKELIHOOD FUNCTION	=	-559.639
NUMBER OF OBSERVATIONS	=	47

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	5734.3	25229	0.22729
TVCHLP	1.0829	0.68333E-01	15.848

A-3 GULF STATES UTILITIES COMPANY

MODEL: GSU

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCGSU	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AQTGSU	-	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
CAPINSN	-	INSTRUMENT FOR CAPGSUN
CAPINST	-	INSTRUMENT FOR CAPGSUT
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
GRPPNU	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPGSUN	-	INDUSTRIAL AVERAGE PRICE (NON-TEXAS):000'S OF $ PER MWH
IAPGSUT	-	INDUSTRIAL AVERAGE PRICE (TEXAS):000'S OF $ PER MWH
IAPINST	-	INSTRUMENT FOR IAPGSUT
ISGSUT	-	INDUSTRIAL SALES (TEXAS):MWH
MATGSU	-	MOVING AVERAGE TOTAL SALES:MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE

PPNUC	-	CONDITIONAL VARIABLE
QTGSU	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST ESTIMATE:000'S OF $
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
TVCGSU	-	TOTAL FUEL AND PURCHASED POWER EXPENSE REQUIREMENTS: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 $
VCPPNU	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S

EXOGENOUS:

C	-	CONSTANT TERM
CCDDINSN	-	INSTRUMENT FOR (NON-TEXAS) COMMERCIAL COOLING DEGREE DAYS
CCDDINST	-	INSTRUMENT FOR (TEXAS) COMMERCIAL COOLING DEGREE DAYS
CCGSUN	-	COMMERCIAL CUSTOMERS (NON-TEXAS):NUMBER OF CUSTOMERS
CCGSUT	-	COMMERCIAL CUSTOMERS (TEXAS):NUMBER OF CUSTOMERS
CDDGSUT	-	TEXAS 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

A-3 GULF STATES UTILITIES COMPANY

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
GCPPNU	-	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
ISGUN	-	INDUSTRIAL SALES (NON-TEXAS):MWH
ISTDUM	-	DUMMY FOR TEXAS INDUSTRIAL SALES
MATFCGSU	-	FOUR-QUARTER MOVING AVERAGE TOTAL FIXED COSTS: 000'S OF $
NAGGSUT	-	NON-AGRICULTURAL EMPLOYMENT IN TEXAS GSU SERVICE AREA:000'S OF $
OSGSUN	-	OTHER NON-TEXAS SALES:MWH
OSGSUT	-	OTHER TEXAS SALES:MWH
PNGCOM	-	PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS: $ PER MCF
PNGRES	-	PRICE OF NATURAL GAS TO RESIDENTIAL CUSTOMERS: $ PER MCF
POPGSUN	-	SERVICE AREA POPULATION (NON-TEXAS):THOUSANDS OF PERSONS
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
RCGSUN	-	RESIDENTIAL CUSTOMERS (NON-TEXAS): NUMBER OF CUSTOMERS
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)

RPIGSUT	-	REAL TEXAS PERSONAL INCOME(BILLIONS OF DOLLARS)
UFCNG	-	VARIABLE COST TO PRODUCE ONE KWH 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
UFCPPNU	-	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(-1)/PNGRES(-1))*RCGSUT
CAPINST	=	(CAPGSUT/PNGCOM)*CCGSUT
IAPINST	=	IAPGSUT(-1)/CPITX(-1)
RAPINSN	=	(RAPGSUN(-1)/PNGRES(-1))*RCGSUN
CAPINSN	=	(CAPGSUN/PNGCOM)*CCGSUN
TSGSUT	=	RSGSUT+CSGSUT+ISGSUT+WSGSUT+OSGSUT
TSGSUN	=	RSGSUN+CSGSUN+ISGSUN+WSGSUN+OSGSUN
TSGSU	=	TSGSUT+TSGSUN
MATSGSU	=	(TSGSU+TSGSU(-1)+TSGSU(-2)+TSGSU(-3))/4
AFCGSU	=	MATFCGSU/MATSGSU
AQTGSU	=	QTGSU/TSGSU
GENRGSU	=	(RSGSUT+RSGSUN)*ILFRSGSU+(CSGSUT+CSGSUN)*ILFCSGSU+ (ISGSUT+ISGSUN)*ILFISGSU+(WSGSUT+WSGSUN)*ILFWSGSU+ (OSGSUT+OSGSUN)*ILFOSGSU
PPNUC	=	GENRGSU-GCPPNU
PLNTAC	=	PPNUC-GCPLNTA
PLNTBC	=	PLNTAC-GCPLNTB
PLNTCC	=	PLNTBC-GCPLNTC
PLNTDC	=	PLNTCC-GCPLNTD
GRPPNU	=	(PPNUC>0)*GCPPNU+(PPNUC<0)*GENRGSU

VCPPNU	=	GRPPNU*UFCPPNU
GRPLNTA	=	(PPNUC>0)*((PLNTAC>0)*GCPLNTA+(PLNTAC<0)*PPNUC)
VCPLNTA	=	GRPLNTA*UFCPLNTA
GRPLNTB	=	(PPNUC>0)*(PLNTAC>0)*((PLNTBC>0)*GCPLNTB+ (PLNTBC<0)*PLNTAC)
VCPLNTB	=	GRPLNTB*UFCPLNTB
GRPLNTC	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)* ((PLNTCC>0)*GCPLNTC+(PLNTCC<0)*PLNTBC)
VCPLNTC	=	GRPLNTC*UFCPLNTC
GRPLNTD	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)* ((PLNTDC>0)*GCPLNTD+(PLNTDC<0)*PLNTCC)
VCPLNTD	=	GRPLNTD*UFCPLNTD
GRNG	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)* (PLNTDC>0)*PLNTDC
VCNG	=	GRNG*UFCNG
TVCGSU	=	VCPPNU+VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+VCNG

EQUATION ESTIMATES

2SLS ESTIMATION

EQUATION 1: TEXAS RESIDENTIAL SALES

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

SUM OF SQUARED RESIDUALS	=	0.773505E+11
STANDARD ERROR OF THE REGRESSION	=	42914.8
MEAN OF DEPENDENT VARIABLE	=	722480.
STANDARD DEVIATION	=	183102.
R^2	=	0.950912
ADJUSTED R^2	=	0.945069
DURBIN-WATSON STATISTIC	=	1.6858
F-STATISTIC	=	162.719
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.41499E+06	0.19848E+06	-2.0908
RSGSUT(-4)	0.53795	0.83318E-01	6.4565
RAPINST	-37.758	24.241	-1.5576
RPIGSUT	0.68430E+06	0.28493E+06	2.4016
RCDDINST	0.11933E-02	0.20428E-03	5.8415
RHDDINST	0.12097E-02	0.22685E-03	5.3325

2SLS ESTIMATION

EQUATION 2: NON-TEXAS RESIDENTIAL SALES

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

SUM OF SQUARED RESIDUALS = 0.844752E+11

STANDARD ERROR OF THE REGRESSION = 44847.7

MEAN OF DEPENDENT VARIABLE = 757523.

STANDARD DEVIATION = 217809.

R^2 = 0.962275

ADJUSTED R^2 = 0.957784

DURBIN-WATSON STATISTIC = 1.8276

F-STATISTIC = 213.317

NUMBER OF OBSERVATIONS = 48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-40190.	0.14028E+06	-0.28650
RSGSUN(-4)	0.81990	0.16823	4.8736
RAPINSN	-23.625	20.372	-1.1596
RPIGSUN	0.11979E+06	0.13982E+06	0.85675
RCDDINSN	0.51524E-03	0.40121E-03	1.2842
RHDDINSN	0.41097E-03	0.28716E-03	1.4311

2SLS ESTIMATION

EQUATION 3: TEXAS COMMERCIAL SALES

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

SUM OF SQUARED RESIDUALS	=	0.100901E+11
STANDARD ERROR OF THE REGRESSION	=	15318.4
MEAN OF DEPENDENT VARIABLE	=	465038.
STANDARD DEVIATION	=	78092.0
R^2	=	0.964796
ADJUSTED R^2	=	0.961522
DURBIN-WATSON STATISTIC	=	1.4805
F-STATISTIC	=	294.617
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.35444E+06	49674.	-7.1354
CSGSUT(-1)	0.35256	0.39920E-0	8.8317
POPGSUT	654.51	76.424	8.5643
CCDDINST	0.54077E-0	0.31615E-03	17.105
CHDDINST	0.31608E-02	0.47744E-03	6.6203

2SLS ESTIMATION

EQUATION 4: NON-TEXAS COMMERICAL SALES

CSGSUN = d0 + d1*CSGSUN(-1) + d2*POPGSUN + d3*CCDDINSN + d4*CHDDINSN

SUM OF SQUARED RESIDUALS	=	0.263990E+11
STANDARD ERROR OF THE REGRESSION	=	24777.6

MEAN OF DEPENDENT VARIABLE	=	662225.
STANDARD DEVIATION	=	104316.
R^2	=	0.948383
ADJUSTED R^2	=	0.943582
DURBIN-WATSON STATISTIC	=	1.8665
F-STATISTIC	=	197.516
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.30546E+06	92301.	-3.3094
CSGSUN(-1)	0.33416	0.44742E-01	7.4686
POPGSUN	499.33	99.042	5.0416
CCDDINSN	0.68813E-02	0.44385E-03	15.504
CHDDINSN	0.35748E-02	0.59188E-03	6.0398

2SLS ESTIMATION USING COCHRANE-ORCUTT ITERATIVE TECHNIQUE

EQUATION 5: TEXAS INDUSTRIAL SALES

ISGSUT = e0 + e1*IAPINST + e2*NAGGSUT + e3*CDDGSUT + e4*ISTDUM

FINAL VALUE OF RHO	=	0.754778
STANDARD ERROR OF RHO	=	0.956845E-01
T-STATISTIC FOR RHO	=	7.88819
SUM OF SQUARED RESIDUALS	=	0.921513E+11
STANDARD ERROR OF THE REGRESSION	=	46841.0
MEAN OF DEPENDENT VARIABLE	=	365108.
STANDARD DEVIATION	=	53536.6
R^2	=	0.302290
ADJUSTED R^2	=	0.235841
DURBIN-WATSON STATISTIC	=	1.7584
LOG OF LIKELIHOOD FUNCTION	=	-569.509

NUMBER OF OBSERVATIONS = 47

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.90746E+06	0.65504E+06	1.3854
IAPINST	-0.51781E+07	0.89177E+07	-0.58066
NAGGSUT	2418.4	2509.2	0.96379
CDDGSUT	32.817	9.4302	3.4800
ISTDUM	70379.	38812.	1.8133

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 6: TEXAS RESIDENTIAL AVERAGE PRICE

RAPGSUT = f0 + f1*AQTGSU + f2*AFCGSU

FINAL VALUE OF RHO = 0.879918

STANDARD ERROR OF RHO = 0.637417E-01

T-STATISTIC FOR RHO = 13.8044

SUM OF SQUARED RESIDUALS = 0.115688E-02

STANDARD ERROR OF THE REGRESSION = 0.507034E-02

MEAN OF DEPENDENT VARIABLE = 0.895538E-02

STANDARD DEVIATION = 0.544691E-02

R^2 = 0.215678

ADJUSTED R^2 = 0.180819

DURBIN-WATSON STATISTIC = 1.7850

LOG OF LIKELIHOOD FUNCTION = 186.344

NUMBER OF OBSERVATIONS = 48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.30437E-01	0.12111E-01	2.5133
AQTGSU	0.69924	0.24470	2.8575
AFCGSU	0.70575	0.42621	1.6559

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 7: NON-TEXAS RESIDENTIAL AVERAGE PRICE

RAPGSUN = g0 + g1*AQTGSU + g2*AFCGSU

FINAL VALUE OF RHO	=	0.641496
STANDARD ERROR OF RHO	=	0.111175
T-STATISTIC FOR RHO	=	5.77013
SUM OF SQUARED RESIDUALS	=	0.863969E-03
STANDARD ERROR OF THE REGRESSION	=	0.438170E-02
MEAN OF DEPENDENT VARIABLE	=	0.216263E-01
STANDARD DEVIATION	=	0.631669E-02
R^2	=	0.547218
ADJUSTED R^2	=	0.527094
DURBIN-WATSON STATISTIC	=	1.9060
LOG OF LIKELIHOOD FUNCTION	=	193.830
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.18719E-01	0.49765E-02	3.7614
AQTGSU	0.71463	0.22474	3.1798
AFCGSU	0.92370	0.18495	4.9944

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 8: TEXAS COMMERCIAL AVERAGE PRICE

CAPGSUT = h0 + h1*AQTGSU + h2*AFCGSU

FINAL VALUE OF RHO	=	0.833385
STANDARD ERROR OF RHO	=	0.780474E-01
T-STATISTIC FOR RHO	=	10.6779
SUM OF SQUARED RESIDUALS	=	0.466898E-03

STANDARD ERROR OF THE REGRESSION	=	0.322110E-02
MEAN OF DEPENDENT VARIABLE	=	0.108012E-01
STANDARD DEVIATION	=	0.438421E-02
R^2	=	0.498644
ADJUSTED R^2	=	0.476362
DURBIN-WATSON STATISTIC	=	1.9258
LOG OF LIKELIHOOD FUNCTION	=	208.272
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.24177E-01	0.62057E-02	3.8959
AQTGSU	0.68051	0.15690	4.3372
AFCGSU	0.78949	0.22290	3.5420

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 9: NON-TEXAS COMMERCIAL AVERAGE PRICE

CAPGSUN = i0 + i1*AQTGSU + i2*AFCGSU

FINAL VALUE OF RHO	=	0.774103
STANDARD ERROR OF RHO	=	0.909160E-01
T-STATISTIC FOR RHO	=	8.51449
SUM OF SQUARED RESIDUALS	=	0.417608E-03
STANDARD ERROR OF THE REGRESSION	=	0.304634E-02
MEAN OF DEPENDENT VARIABLE	=	0.125672E-01
STANDARD DEVIATION	=	0.439358E-02
R^2	=	0.550965
ADJUSTED R^2	=	0.531008
DURBIN-WATSON STATISTIC	=	1.7837
LOG OF LIKELIHOOD FUNCTION	=	211.086
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.17521E-01	0.46436E-02	3.7731
AQTGSU	0.67564	0.15303	4.4150
AFCGSU	0.76302	0.17261	4.4206

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 10: TEXAS INDUSTRIAL AVERAGE PRICE

IAPGSUT = j0 + j1*AQTGSU + j2*AFCGSU

FINAL VALUE OF RHO	=	0.759495
STANDARD ERROR OF RHO	=	0.945495E-01
T-STATISTIC FOR RHO	=	8.03278
SUM OF SQUARED RESIDUALS	=	0.265599E-03
STANDARD ERROR OF THE REGRESSION	=	0.242944E-02
MEAN OF DEPENDENT VARIABLE	=	0.918011E-02
STANDARD DEVIATION	=	0.336535E-02
R^2	=	0.511541
ADJUSTED R^2	=	0.489832
DURBIN-WATSON STATISTIC	=	2.1724
LOG OF LIKELIHOOD FUNCTION	=	221.974
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.16192E-01	0.36400E-02	4.4484
AQTGSU	0.60342	0.12276	4.9155
AFCGSU	0.25168	0.13359	1.8840

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 11: NON-TEXAS INDUSTRIAL AVERAGE PRICE

IAPGSUN = k0 + k1*AQTGSU + k2*AFCGSU

FINAL VALUE OF RHO	=	0.694078
STANDARD ERROR OF RHO	=	0.104402
T-STATISTIC FOR RHO	=	6.64812
SUM OF SQUARED RESIDUALS	=	0.341114E-03
STANDARD ERROR OF THE REGRESSION	=	0.275324E-02
MEAN OF DEPENDENT VARIABLE	=	0.116733E-01
STANDARD DEVIATION	=	0.407171E-02
R^2	=	0.568916
ADJUSTED R^2	=	0.549757
DURBIN-WATSON STATISTIC	=	1.6960
LOG OF LIKELIHOOD FUNCTION	=	216.070
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.84012E-02	0.34360E-02	2.4451
AQTGSU	0.60990	0.13906	4.3858
AFCGSU	0.56164	0.12830	4.3775

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 12: TOTAL FUEL EXPENSE & PURCHASED POWER COST

QTGSU = l0 + l1*TVCGSU

FINAL VALUE OF RHO	=	0.284976
STANDARD ERROR OF RHO	=	0.139661
T-STATISTIC FOR RHO	=	2.04049
SUM OF SQUARED RESIDUALS	=	0.172297E+11
STANDARD ERROR OF THE REGRESSION	=	19353.5

MEAN OF DEPENDENT VARIABLE	=	116600.
STANDARD DEVIATION	=	34297.4
R^2	=	0.688604
ADJUSTED R^2	=	0.681835
DURBIN-WATSON STATISTIC	=	2.0204
LOG OF LIKELIHOOD FUNCTION	=	-540.920
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	22985.	13498.	1.7028
TVCGSU	1.0236	0.95703E-01	10.696

A-4 CENTRAL POWER AND LIGHT COMPANY

MODEL: CPL

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCCPL	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AQTCPL	-	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
GRPPNU	-	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

PPNUC - CONDITIONAL VARIABLE

QTCPL - TOTAL FUEL EXPENSE AND PURCAHSED POWER COST ESTIMATE:000'S OF $

RAPCPL - RESIDENTIAL AVERAGE PRICE:000'S OF $ PER MWH

RAPINST - INSTRUMENT FOR RAPCPL

RSCPL - RESIDENTIAL SALES:MWH

TSCPL - TOTAL SYSTEM SALES:MWH

TVCCPL - TOTAL FUEL AND PURCHASED POWER EXPENSE REQUIREMENTS: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 $

VCPPNU - PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $

WAPCPL - WHOLESALE AVERAGE PRICE:000'S OF $ PER MWH

WAPINST - INSTRUMENT FOR WAPCPL

WSCPL - WHOLESALE SALES:MWH

EXOGENOUS:

C - CONSTANT TERM

CCCPL - COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS

CCDDINST - INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS

CDDCPL - COOLING DEGREE DAYS:NUMBER OF DAYS

CPITX - TEXAS CONSUMER PRICE INDEX

GCPLNTA - GENERATION CAPABILITY OF PLANT A: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
GCPPNU	-	GENERATION CAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
GNPD	-	GROSS NATIONAL PRODUCT DEFLATOR
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 $
OAPDUM	-	OTHER AVERAGE PRICE DUMMY
PNGCOM	-	PRICE OF NATURAL GAS TO COMMERCIAL CUSTOMERS: $ PER MCF
PNGIND	-	PRICE OF NATURAL GAS TO INDUSTRIAL CUSTOMERS: $ PER MCF
POPCPL	-	POPULATION DATA:000'S OF PERSONS
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 KWH 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 $

UFCPPNU	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $
WAPDUM1	-	WHOLESALE AVERAGE PRICE DUMMY # 1
WAPDUM2	-	WHOLESALE AVERAGE PRICE DUMMY # 2
WSDUM	-	WHOLESALE SALES DUMMY

IDENTITIES

RAPINST	=	(RAPCPL(-4)/CPITX(-4))*RCCPL
CAPINST	=	(CAPCPL(-2)/PNGCOM(-2))*CCCPL
IAPINST	=	IAPCPL/PNGIND
WAPINST	=	WAPCPL/GNPD
OAPINST	=	OAPCPL/GNPD
TSCPL	=	RSCPL+CSCPL+ISCPL+WSCPL+OSCPL
AQTCPL	=	QTCPL/TSCPL
AFCCPL	=	MATFCCPL/(TSCPL+TSCPL(-1)+TSCPL(-2)+ TSCPL(-3))
GENRCPL	=	RSCPL*ILFRSCPL+CSCPL*ILFCSCPL+ISCPL* ILFISCPL+WSCPL*ILFWSCPL+OSCPL*ILFOSCPL
PPNUC	=	GENRCPL-GCPPNU
PLNTAC	=	PPNUC-GCPLNTA
PLNTBC	=	PLNTAC-GCPLNTB
PLNTCC	=	PLNTBC-GCPLNTC
PLNTDC	=	PLNTCC-GCPLNTD
PLNTEC	=	PLNTDC-GCPLNTE
PLNTFC	=	PLNTEC-GCPLNTF
PLNTGC	=	PLNTFC-GCPLNTG
GRPPNU	=	(PPNUC>0)*GCPPNU+(PPNUC<0)*GENRCPL
VCPPNU	=	GRPPNU*UFCPPNU
GRPLNTA	=	(PPNUC>0)*((PLNTAC>0)*GCPLNTA+(PLNTAC<0)* PPNUC)
VCPLNTA	=	GRPLNTA*UFCPLNTA
GRPLNTB	=	(PPNUC>0)* (PLNTAC>0)*((PLNTBC>0)*GCPLNTB+ (PLNTBC<0)*PLNTAC)
VCPLNTB	=	GRPLNTB*UFCPLNTB
GRPLNTC	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*((PLNTCC>0)* GCPLNTC+(PLNTCC<0)*PLNTBC)
VCPLNTC	=	GRPLNTC*UFCPLNTC

GRPLNTD	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)* ((PLNTDC>0)*GCPLNTD+(PLNTDC<0)*PLNTCC)
VCPLNTD	=	GRPLNTD*UFCPLNTD
GRPLNTE	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)* (PLNTDC>0)*((PLNTEC>0)*GCPLNTE+(PLNTEC<0)*PLNTDC)
VCPLNTE	=	GRPLNTE*UFCPLNTE
GRPLNTF	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0) *(PLNTEC>0)*((PLNTFC>0)*GCPLNTF+(PLNTFC<0)*PLNTEC)
VCPLNTF	=	GRPLNTF*UFCPLNTF
GRPLNTG	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)* (PLNTDC>0)*(PLNTEC>0)*(PLNTFC>0)*((PLNTGC>0)* GCPLNTG+ (PLNTGC<0)*PLNTFC)
VCPLNTG	=	GRPLNTG*UFCPLNTG
GRNG	=	(PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)* (PLNTDC>0)*(PLNTEC>0)*(PLNTFC>0)*(PLNTGC>0)*PLNTGC
VCNG	=	GRNG*UFCNG
TVCCPL	=	VCPPNU+VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+ VCPLNTE+VCPLNTF+VCPLNTG+VCNG

EQUATION ESTIMATES

2SLS ESTIMATION USING COCHRANE-ORCUTT ITERATIVE TECHNIQUE

EQUATION 1: RESIDENTIAL SALES

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

FINAL VALUE OF RHO	=	-0.959796
STANDARD ERROR OF RHO	=	0.413867E-01
T-STATISTIC FOR RHO	=	-23.1909
SUM OF SQUARED RESIDUALS	=	0.112636E+12
STANDARD ERROR OF THE REGRESSION	=	53065.0
MEAN OF DEPENDENT VARIABLE	=	0.204532E+07
STANDARD DEVIATION	=	409040.
R^2	=	0.985040
ADJUSTED R^2	=	0.983170

DURBIN-WATSON STATISTIC = 1.2390

LOG OF LIKELIHOOD FUNCTION = -562.503

NUMBER OF OBSERVATIONS = 46

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.27235E+06	0.13489E+06	-2.0191
RSCPL(-1)	0.56771	0.50345E-01	11.276
RAPINST	-8.5426	4.4132	-1.9357
RPICPL	0.22994E+06	0.15349E+06	1.4981
RCDDINST	0.12083E-02	0.82339E-04	14.675
RHDDINST	0.80097E-03	0.19094E-03	4.1949

2SLS ESTIMATION USING COCHRANE-ORCUTT ITERATIVE TECHNIQUE

EQUATION 2: COMMERCIAL SALES

CSCPL = b0 + b1*CSCPL(-4) + b*CAPINST + b3*POPCPL + b4*CCDDINST

FINAL VALUE OF RHO = 0.436480

STANDARD ERROR OF RHO = 0.132656

T-STATISTIC FOR RHO = 3.29032

SUM OF SQUARED RESIDUALS = 0.233065E+11

STANDARD ERROR OF THE REGRESSION = 23842.2

MEAN OF DEPENDENT VARIABLE = 485795.

STANDARD DEVIATION = 124266.

R^2 = 0.966625

ADJUSTED R^2 = 0.963369

DURBIN-WATSON STATISTIC = 1.9294

LOG OF LIKELIHOOD FUNCTION = -526.268

NUMBER OF OBSERVATIONS = 46

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	2358.6	99039.	0.23815E-01
CSCPL(-4)	0.93915	0.60635E-01	15.489
CAPINST	-116.69	85.390	-1.3665
POPCPL	109.66	82.150	1.3349
CCDDINST	0.23267E-03	0.14956E-03	1.5557

2SLS ESTIMATION

EQUATION 3: INDUSTRIAL SALES

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

SUM OF SQUARED RESIDUALS = 0.224120E+12

STANDARD ERROR OF THE REGRESSION = 73049.3

MEAN OF DEPENDENT VARIABLE = 0.132002E+07

STANDARD DEVIATION = 178068.

R^2 = 0.850003

ADJUSTED R^2 = 0.832146

DURBIN-WATSON STATISTIC = 2.1575

F-STATISTIC = 47.4556

NUMBER OF OBSERVATIONS = 48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.52912E+06	0.22527E+06	2.3489
ISCPL(-1)	0.47143	0.13530	3.4842
IAPINST	-0.12747E+08	0.93349E+07	-1.3655
POPCPL	201.67	126.16	1.5985
CDDCPL	66.131	17.717	3.7326
ISDUM	-0.19620E+06	60972.	-3.2180

2SLS ESTIMATION

EQUATION 4: WHOLESALE SALES

WSCPL = d0 + d1*WAPINST + d2*POPCPL + d3*CDDCPL + d4*HDDCPL + d4*WSDUM

SUM OF SQUARED RESIDUALS	=	0.276795E+10
STANDARD ERROR OF THE REGRESSION	=	8118.11
MEAN OF DEPENDENT VARIABLE	=	100366.
STANDARD DEVIATION	=	38938.9
R^2	=	0.961159
ADJUSTED R^2	=	0.956535
DURBIN-WATSON STATISTIC	=	2.1098
F-STATISTIC	=	207.865
NUMBER OF OBSERVATIONS	=	48

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-0.15190E+06	32937.	-4.6120
WAPINST	-78009.	49259.	-1.5836
POPCPL	138.34	16.350	8.4614
CDDCPL	19.302	4.4991	4.2901
HDDCPL	23.562	9.9658	2.3643
WSDUM	58842.	4058.2	14.499

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 5: OTHER SALES

OSCPL = e0 + e1*OAPINST + e2*POPCPL + e3*CDDCPL + e4*HDDCPL

FINAL VALUE OF RHO	=	0.215916
STANDARD ERROR OF RHO	=	0.153081
T-STATISTIC FOR RHO	=	1.41047

SUM OF SQUARED RESIDUALS = 0.566358E+10

STANDARD ERROR OF THE REGRESSION = 11612.4

MEAN OF DEPENDENT VARIABLE = 91427.6

STANDARD DEVIATION = 27199.5

R^2 = 0.833814

ADJUSTED R^2 = 0.817987

DURBIN-WATSON STATISTIC = 1.7868

LOG OF LIKELIHOOD FUNCTION = -503.983

NUMBER OF OBSERVATIONS = 47

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-61070.	33531.	-1.8213
OAPINST	-62001.	48708.	-1.2729
POPCPL	72.064	18.677	3.8585
CDDCPL	54.259	6.1460	8.8282
HDDCPL	42.418	14.193	2.9887

2SLS ESTIMATION

EQUATION 6: RESIDENTIAL AVERAGE PRICE

RAPCPL = f0 + f1*AQTCPL + f2*AFCCPL

SUM OF SQUARED RESIDUALS = 0.402266E-03

STANDARD ERROR OF THE REGRESSION = 0.329728E-02

MEAN OF DEPENDENT VARIABLE = 0.654761E-01

STANDARD DEVIATION = 0.704432E-02

R^2 = 0.794512

ADJUSTED R^2 = 0.783404

DURBIN-WATSON STATISTIC = 1.6697

F-STATISTIC = 70.5024

NUMBER OF OBSERVATIONS = 40

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.66401E-02	0.53366E-02	1.2442
AQTCPL	1.0614	0.88286E-01	12.023
AFCCPL	0.95371	0.12555	7.5960

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 7: COMMERCIAL AVERAGE PRICE

CAPCPL = g0 + g1*AQTCPL + g2*AFCCPL

FINAL VALUE OF RHO	=	0.150623
STANDARD ERROR OF RHO	=	0.164336
T-STATISTIC FOR RHO	=	0.916557
SUM OF SQUARED RESIDUALS	=	0.361483E-03
STANDARD ERROR OF THE REGRESSION	=	0.316878E-02
MEAN OF DEPENDENT VARIABLE	=	0.584557E-01
STANDARD DEVIATION	=	0.542482E-02
R^2	=	0.679876
ADJUSTED R^2	=	0.662091
DURBIN-WATSON STATISTIC	=	1.8625
LOG OF LIKELIHOOD FUNCTION	=	170.633
NUMBER OF OBSERVATIONS	=	39

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.15457E-01	0.67635E-02	2.2853
AQTCPL	0.96169	0.10423	9.2267
AFCCPL	0.84280	0.15953	5.2830

2SLS ESTIMATION USING MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

EQUATION 8: INDUSTRIAL AVERAGE PRICE

IAPCPL = h0 + h1*AQTCPL + h2*AFCCPL

FINAL VALUE OF RHO	=	0.343343
STANDARD ERROR OF RHO	=	0.154096
T-STATISTIC FOR RHO	=	2.22811
SUM OF SQUARED RESIDUALS	=	0.413165E-03
STANDARD ERROR OF THE REGRESSION	=	0.338774E-02
MEAN OF DEPENDENT VARIABLE	=	0.338252E-01
STANDARD DEVIATION	=	0.462829E-02
R^2	=	0.506175
ADJUSTED R^2	=	0.478741
DURBIN-WATSON STATISTIC	=	1.9008
LOG OF LIKELIHOOD FUNCTION	=	167.976
NUMBER OF OBSERVATIONS	=	39

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.27796E-02	0.87561E-02	0.31745
AQTCPL	0.88214	0.13490	6.5392
AFCCPL	0.75386	0.21038	3.5833

2SLS ESTIMATION

EQUATION 9: WHOLESALE AVERAGE PRICE

WAPCPL = i0 + i1*AQTCPL + i2*AFCCPL + i3*WAPDUM1 + i4*WAPDUM2

SUM OF SQUARED RESIDUALS	=	0.811097E-02
STANDARD ERROR OF THE REGRESSION	=	0.152231E-01

MEAN OF DEPENDENT VARIABLE	=	0.106988
STANDARD DEVIATION	=	0.403001E-01
R^2	=	0.872035
ADJUSTED R^2	=	0.857410
DURBIN-WATSON STATISTIC	=	1.7486
F-STATISTIC	=	59.5802
NUMBER OF OBSERVATIONS	=	40

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.53694E-01	0.37738E-01	1.4228
AQTCPL	0.89072	0.67453	1.3205
AFCCPL	1.0639	1.0628	1.0010
WAPDUM1	0.65036E-01	0.11691E-01	5.5630
WAPDUM2	-0.44506E-01	0.11895E-01	-3.7416

2SLS ESTIMATION

EQUATION 10: OTHER AVERAGE PRICE

OAPCPL = j0 + j1*AQTCPL + j2*AFCCPL + j3*OAPDUM

SUM OF SQUARED RESIDUALS	=	0.254909E-01
STANDARD ERROR OF THE REGRESSION	=	0.266098E-01
MEAN OF DEPENDENT VARIABLE	=	0.304743E-01
STANDARD DEVIATION	=	0.602930E-01
R^2	=	0.823031
ADJUSTED R^2	=	0.808283
DURBIN-WATSON STATISTIC	=	2.0074
F-STATISTIC	=	54.7413
NUMBER OF OBSERVATIONS	=	40

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	0.78455E-03	0.45255E-01	0.17336E-01
AQTCPL	0.59610	0.72096	0.82681
AFCCPL	1.9690	1.1506	1.7112
OAPDUM	-0.12753	0.12515E-01	-10.190

2SLS ESTIMATION

EQUATION 11: TOTAL FUEL EXPENSE & PURCHASED POWER COST

QTCPL = k0 + k1*TVCCPL

SUM OF SQUARED RESIDUALS	=	0.239059E+10
STANDARD ERROR OF THE REGRESSION	=	7931.60
MEAN OF DEPENDENT VARIABLE	=	109964.
STANDARD DEVIATION	=	27030.3
R^2	=	0.917584
ADJUSTED R^2	=	0.915416
DURBIN-WATSON STATISTIC	=	2.0496
F-STATISTIC	=	414.945
NUMBER OF OBSERVATIONS	=	40

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	T-STATISTIC
C	-4759.1	5767.1	-0.82521
TVCCPL	1.0968	0.53819E-01	20.380

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MODEL: CPSB/SA

SYMBOL DECLARATIONS

ENDOGENOUS:

AFCSA	-	AVERAGE FIXED COSTS:000'S OF $ PER MWH
AQTSA	-	AVERAGE FUEL EAND PURCHASED POWER COSTS: 000'S OF $ PER MWH
CAPINST	-	INSTRUMENT FOR CAPSA
CAPSA	-	COMMERCIAL AVERAGE PRICE :000'S OF $ PER MWH
CSSA	-	COMMERCIAL SALES:MWH
GENRSA	-	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
GRPPNU	-	GENERATION REQUIREMENTS FROM PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
IAPSA	-	INDUSTRIAL AVERAGE PRICE:000'S OF $ PER MWH
MATSSA	-	FOUR-QUARTER MOVING AVERAGE OF TOTAL SALES:MWH
PLNTAC	-	CONDITIONAL VARIABLE
PLNTBC	-	CONDITIONAL VARIABLE
PLNTCC	-	CONDITIONAL VARIABLE
PLNTDC	-	CONDITIONAL VARIABLE
PLNTEC	-	CONDITIONAL VARIABLE
PLNTFC	-	CONDITIONAL VARIABLE
PLNTGC	-	CONDITIONAL VARIABLE
PPNUC	-	CONDITIONAL VARIABLE
QTSA	-	TOTAL FUEL EXPENSE AND PURCHASED POWER COST ESTIMATE:000'S OF $

RAPINST	-	INSTRUMENT FOR RAPSA
RAPSA	-	RESIDENTIAL AVERAGE PRICE:000'S OF PER MWH
RSSA	-	RESIDENTIAL SALES:MWH
TSSA	-	TOTAL SYSTEM SALES:MWH
TVCSA	-	TOTAL FUEL AND PURCHASED POWER EXPENSE REQUIREMENTS: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 $
VCPPNU	-	PURCHASED POWER COST FROM NON-UTILITY SOURCES: 000'S OF $

EXOGENOUS:

C	-	CONSTANT TERM
CCDDINST	-	INSTRUMENT FOR COMMERCIAL COOLING DEGREE DAYS
CCSA	-	COMMERCIAL CUSTOMERS:NUMBER OF CUSTOMERS
CHDDINST	-	INSTRUMENT FOR COMMERCIAL HEATING DEGREE DAYS
CPITX	-	TEXAS CONSUMER PRICE INDEX
GCPLANTA	-	GENERATION CAPABILITY OF PLANT A:MWH
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
GCPPNU	-	GENERATIONCAPABILITY OF PURCHASED POWER FROM NON-UTILITY SOURCES:MWH
ILFSA	-	SYSTEM LOSS FACTOR
ISSA	-	INDUSTRIAL SALES:MWH
MATFCSA	-	FOUR QUARTER MOVING SUM TOTAL FIXED COSTS: 000'S OF $

NAGCPS	-	NON-AGRICULTURAL EMPLOYMENT IN CPS SERVICE AREA:000'S OF$
OSSA	-	OTHER SALES:MWH
PPIF	-	PRODUCER PRICE INDEX:FINISHED GOODS
RCDDINST	-	INSTRUMENT FOR RESIDENTIAL COOLING DEGREE DAYS
RCSA	-	RESIDENTIAL CUSTOMERS:NUMBER OF CUSTOMERS
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
UFCPPNU	-	UNIT COST OF PURCHASED POWER FROM NON-UTILITY SOURCES:000'S OF $ PER MWH

IDENTITIES:

RAPINST	=	(RAPSA(-4)/CPITX(-4))*RCSA
CAPINST	=	(CAPSA(-2)/PPIF(-2))*CCSA
TSSA	=	RSSA+CSSA+ISSA+OSSA
MATSSA	=	(TSSA+TSSA(-1)+TSSA(-2)+TSSA(-3))/4
AQTSA	=	QTSA/TSSA
AFCSA	=	MATFCSA/MATSSA
GENRSA	=	TSSA * ILFSA
PPNUC	=	GENRSA-GCPPNU
PLNTAC	=	PPNUC-GCPLNTA
PLNTBC	=	PLNTAC-GCPLNTB
PLNTCC	=	PLNTBC-GCPLNTC

PLNTDC = PLNTCC-GCPLNTD

PLNTEC = PLNTDC-GCPLNTE

PLNTFC = PLNTEC-GCPLNTF

PLNTGC = PLNTFC-GCPLNTG

GRPPNU = (PPNUC>0)*GCPPNU+(PPNUC<0)*GENRSA

VCPPNU = GRPPNU*UFCPPNU

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

VCPLNTA = GRPLNTA*UFCPLNTA

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

VCPLNTB = GRPLNTB*UFCPLNTB

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

VCPLNTC = GRPLNTC*UFCPLNTC

GRPLNTD = (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*((PLNTDC>0)* GCPLNTD+(PLNTDC<0)*PLNTCC)

VCPLNTD = GRPLNTD*UFCPLNTD

GRPLNTE = (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)* ((PLNTEC>0)*GCPLNTE+(PLNTEC<0)*PLNTDC)

VCPLNTE = GRPLNTE*UFCPLNTE

GRPLNTF = (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)* (PLNTEC>0)*((PLNTFC>0)*GCPLNTF+(PLNTFC<0)*PLNTEC)

VCPLNTF = GRPLNTF*UFCPLNTF

GRPLNTG = (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)* (PLNTEC>0)*(PLNTFC>0)*((PLNTGC>0)*GCPLNTG+(PLNTGC<0)*PLNTFC)

VCPLNTG = GRPLNTG*UFCPLNTG

GRNG = (PPNUC>0)*(PLNTAC>0)*(PLNTBC>0)*(PLNTCC>0)*(PLNTDC>0)* (PLNTEC>0)*(PLNTFC>0)*(PLNTGC>0)*PLNTGC

VCNG = GRNG*UFCNG

TVCSA = VCPPNU+VCPLNTA+VCPLNTB+VCPLNTC+VCPLNTD+VCPLNTE+ VCPLNTF+VCPLNTG+VCNG