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MASTER

THE REGIONAL DEMAND

FORECASTING MODEL

1977 and 1978 VERSIONS

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INTRODUCTION

The Regional Demand Forecasting Model (RDFOR) is an econometric and simulation system designed to forecast annual consumption of various fuels by region from 1976 through 1990. Its purposes are to (1) provide the demand side of the Project Independence Evaluation System (PIES); (2) enhance our empirical insights into the structure of U.S. energy demand; and (3) assist policy-makers in their decisions on and formulations of various energy policies and/or scenarios. The latter two purposes can be performed independent of PIES.

PIES is intended to provide policy-makers in various energy fields of the U.S. Government with a comprehensive, analytical tool of measurement--comprehensive in that it considers the complex interactions of energy in all its varied forms and analytical in that statistical and econometric techniques are used to obtain quantitative assessments of various proposed policy scenarios.

In addition to RDFOR, which provides the demand side of the PIES, a set of supply representations exists for each of the various fuels modeled. These supply representations are developed through the use of linear programming techniques. The link between supply and demand for various energy forms is provided by an integrating mechanism {1} which, through an iterative process, estimates market clearing prices and quantities consumed of various fuels for the years 1980, 1985, and 1990.

The purpose of this report is to document the demand forecasting model, RDFOR. Chapter I presents an overview of the structure of RDFOR as well as its linkages with other models within the PIES model. An important link between RDFOR and PIES is the Demand Interface System (DFACE) which prepares the output of RDFOR for input into PIES. Chapter II provides an in-depth analysis of the data bases used in the estimation and simulation of RDFOR. It presents an analysis of trends in energy data by fuel and by sector for both the United States as a whole and for each of the 10 DOE regions. A detached appendix to this Chapter presents actual historical time series utilized in the estimation and simulation of the model.

Chapter III provides a detailed analysis of the theoretical structure of RDFOR. Both the specifications of the equations and their relationships to other econometric demand models are examined. In addition, Chapter III analyzes a transportation sector model and a minor fuels sector model which differ in structure from the other sectors within RDFOR. This chapter also

examines the econometric implementation of RDFOR. Much emphasis is placed on an analysis of the error structure and its implications for the estimated parameters of the model. The econometric and statistical methods employed to estimate the model are evaluated and the implications of the various restrictions imposed by the specification are pointed out. Finally, the results of the estimation procedure are evaluated in light of theoretical expectations. These results are compared with the results of similar studies in order to place the entire RDFOR model in the proper perspective for energy forecasting.

Chapter IV describes the simulation of RDFOR and its resultant forecasts. Emphasis is placed on the various restrictions and transformations performed prior to and during the simulation. A description of scenario implementation is also included. An analysis of the changes made in the simulation equations from the specification of the estimation equations is an important part of this chapter.

Ensuing to this report is a self-contained User's Manual which provides information on the interpretation, utilization and implementation of RDFOR simulation software packages. This manual is essentially a "how to" document and is intended to enable the user to implement the RDFOR system and evaluate its results.

{1}

Documentation of the integrating mechanism is provided by Logistics Management Institute, The Integrating Model of the Project Independence Evaluation System, Washington, D.C.: LMI, September 1977.

I. PIES AND RDFOR

To prepare the reader for the detailed description of RDFOR in later chapters, an overview is presented here of the entire Project Independence Evaluation System (PIES), the role of RDFOR within PIES, and the scope of the RDFOR model. Section One summarizes PIES and its relation to RDFOR. This summary is condensed, and the interested reader is encouraged to refer to {1} and {2} for further details. Section Two gives an overview of the RDFOR model.

1. The Project Independence Evaluation System (PIES)

PIES forecasts the state of the nation's energy system for 1980, 1985, and 1990. The model predicts energy consumption levels in each of the United States' ten DOE regions {3} and portrays the distribution of this consumption among ten fuel products:

(1) Distillate oil	(6) Residual oil
(2) Electricity	(7) Steam coal
(3) Gasoline	(8) Other petroleum products
(4) Metallurgical coal	(9) Liquid gases
(5) Natural gas	(10) Jet fuel

The model further determines the sources of these fuels by DOE regions. Conversion of fuels into energy suitable for final consumption and transportation of fuel or energy from one part of the country to another is also determined. An iterative process of forcing demand and supply toward equilibrium determines the most efficient energy use.

PIES is composed of various models: a collection of supply representations, an econometric demand model (RDFOR) and an integrating model. The supply representations are developed through the use of a linear programming model. The econometric demand model (RDFOR) provides the demand side of the overall system. The integrating model provides the framework for analysis and combines the output of the other models to estimate future market clearing prices and supply and demand quantities. This report documents only the econometric demand model (RDFOR).

The structure of PIES as well as the function of RDFOR within the overall model are depicted in Figures 1 and 2. The system consists of several different computer programs which are run at different times, the output of one being the input for the next.

Figure 1. Process Schematic of PIES

Insert Fig. 1

Figure 2. Structure of PIES and Place of RDFOR

Insert Fig. 2

Raw data are submitted in widely varying formats from many offices within and outside DOE. These raw data first are formatted uniformly across sectors before introduction into the integrating model. The results of this uniform formatting are known as the "Standard Tables." There are three categories of Standard Tables: facilities, materials and transportation. These tables store the data in a form which can be used by a matrix generator routine (described below) to form a linear programming matrix suitable for use by the equilibrating routine without further arithmetical changes. Separate programs permit the Standard Tables to be printed out either in full or in part.

The matrix generator converts the Standard Tables to the required linear programming matrix format to generate the transportation linkages. Data can be altered through the use of a separate routine which has the ability to change the formatted matrices before they are used by the equilibrating routine. At this point, prices and estimates of quantities for the various DOE energy regions are entered into a control program, where the equilibration process occurs. This control program reads the demand files--the projected quantities, prices and associated elasticities of the various fuel products by region--and constructs the demand function approximations required by the integrating model. The equilibration process--matching demand and supply--takes place, and a test is made to determine if another iteration should be performed. When no further iterations are necessary, a number of different output writers are available to report the final solution.

2. An Overview of the Regional Demand Forecasting Model (RDFOR)

RDFOR is an econometric model which forecasts annual energy demand by fuel, sector and DOE regions from 1977 through 1990. It is a major component of PIES and is based on the premise that a rich set of historical data exists which can be used to devise parameters relevant to the future conditions being simulated by the overall PIES model.

The RDFOR model estimates and predicts demand for 14 fuels:

(1) Asphalt	(8) Metallurgical Coal
(2) Coal	(9) Natural Gas
(3) Distillate Fuel	(10) Oil
(4) Electricity	(11) Petroleum Coke
(5) Gasoline	(12) Petroleum Products
(6) Jet Fuel	(13) Residual Fuel
(7) Liquid Gases	(14) Total Fuels.

These fuels are spread over four sectors:

- (1) Commercial
- (2) Industrial
- (3) Residential
- (4) Transportation.

In addition, feedstocks and raw materials comprise two smaller sectors, which are modeled within RDFOR and PIES by DOE region.

RDFOR provides estimates of the prices, demands and elasticities for 30 fuel/sector pairs for the ten DOE regions. A fuel/sector pair consists of a fuel allocated over a specific sector of the economy. For example, natural gas is a fuel while natural gas-household and natural gas-industrial are fuel/sector pairs. In addition to these pairs RDFOR provides information on eight fuels totals; four sector fuels totals; and a total for all fuels. These give 43 fuel choices for analysis. Table 1 represents these choices in a grid pattern. Table 2 lists the fuel/sector pairs and their codes. Table 3 lists the eight fuels totals and their codes. Table 4 lists sector fuels totals and a grand total for all fuels, and their codes. The column labeled "Price Paths Exist" in Table 2 will be explained in a later chapter.

Within RDFOR fuel choices are price-sensitive and price induced substitution is uninhibited. Moreover, dynamic adjustments to changing fuel prices and economic conditions are incorporated into the model. Figure 3 depicts the structure and flow of RDFOR. The preprocessors shown near the top of the figure transform regionally specific raw data for macroeconomic forecasts, initial quantities and prices into standard format files which can be read directly by RDFOR.

In addition to macro variables, prices, quantities and particular conservation programs' effects on the transportation sector, regional parameter values are also preprocessed as input to RDFOR. These values determine how responsive demand is to prices and economic conditions.

Within RDFOR the demands for and the prices of the 30 fuel/sector pairs combine to define points on a demand surface. The slopes of the various demand curves are obtained by perturbing prices and recording the new demands. The log-linearity of the equations permits a single perturbation to derive elasticities. The derived elasticities are intertemporal and fit well within the PIES framework where price changes are 'rolled-in' over time.

Table 1. Fuels and Fuel Sectors of the RDFOR Model

Fuels	Sector				Total**
	1	2	3	4	
1. Asphalt		X			
2. Coal		X	X	X	X
3. Distillate	X	X	X	X	X
4. Electricity	X	X	X	X	X
5. Gasoline				X	
6. Jet Fuel				X	
7. Liquid Gases	X	X	X	X(3)	X
8. Metallurgical Coal			X		
9. Natural Gas	X	X	X		X
10. Oil					X
11. Other Pet. Products					X
12. Petroleum Coke			X		
13. Residual		X	X	X	X
14. Total*	X	X	X	X	X

* Total of all fuels in one sector

**Total of one fuel across all sectors

Legend:

1=Residential

2=Commercial

3=Industrial

4=Transportation, Feedstock and Raw Material

Table 2. 30 Fuel/Sector Pairs

Fuel Description	Fuel Code	Price Paths Exist
Coal		
Household/Commercial Coal	CLHC	
Industrial Coal	CLIN	x
Transportation Coal	CLTR	
Commercial Asphalt	ASCM	
Distillate		
Commercial Distillate	DFCM	x
Industrial Distillate	DFIN	x
Residential Distillate	DFRS	x
Transportation Distillate	DFTR	x
Electricity		
Commercial Electricity	ELCM	x
Industrial Electricity	ELIN	x
Residential Electricity	ELRS	x
Transportation Electricity	ELTR	
Gas--Natural		
Commercial Natural Gas	NGCM	x
Industrial Natural Gas	NGIN	x
Raw Material Natural Gas	NGRM	
Residential Natural Gas	NGRS	x
Gases--Liquid		
Commercial Liquid Gases	LGCM	
Feedstock Liquid Gases	LGFS	
Industrial Liquid Gases	LGIN	x
Raw Materials Liquid Gases	LGRM	
Residential Liquid Gases	LGRS	x
Transportation Liquid Gases	LGTR	
Gasoline		
Transportation Gasoline	GSTR	x
Jet Fuel		
Transportation Jet Fuel	JFTR	x
Metallurgical Coal		
Industrial Metallurgical Coal	MCIN	
Oil		
Raw Material Oil	OLRM	
Petroleum Coke		
Industrial Petroleum Coke	PCIN	

Residual

Commercial Residual	RFCM	X
Industrial Residual	RFIN	X
Transportation Residual	RFTR	X

Table 3. Eight Fuels Totals

Fuel Description	Fuel Code
Total Coal	CLTT
Total Distillate	DFTT
Total Electricity	ELTT
Total Liquid Gases	LGTT
Total Natural Gas	NGTT
Total Oil	OLTT
Total Other Petroleum Products	OPTT
Total Residual	RFTT

Table 4. Sector Fuel Totals

Fuel Description	Fuel Code
Commercial--All Fuels	TTCM
Industrial--All Fuels	TTIN
Residential--All Fuels	TTRS
Transportation--All Fuels	TTTR
Total--All Fuels	TTTT

Figure 3. DEMAND MODEL SCHEMATIC

Insert Fig. 3

The intermediate files containing regional demand points for each price path perturbation are combined with unperturbed prices in RDFOR and control is transferred to the Demand Interface Program (DFACE). Elasticities are calculated and are adjusted for specific scenario demand shifts. The adjusted demand points and elasticity arrays produced by DFACE serve as model inputs to the PIES integrating mechanism. RDFOR and DFACE also produce their own formal reports.

RDFOR draws on a relatively huge data base. In addition to data on prices and quantities of fuels demanded, other inputs to RDFOR are:

- (1) The projection path of fuel prices by sector and region from 1976 to 1990
- (2) Forecasts of population, income, and industrial activity through 1990
- (3) Impacts of nonprice conservation programs, and
- (4) Availability of natural gas markets.

As output, RDFOR provides:

- (1) Forecasts of demands for the 30 fuel/sector pairs.
- (2) The prices of the following fuels:
 - Distillate fuel
 - Gasoline
 - Household electricity
 - Household natural gas
 - Industrial bituminous coal
 - Industrial electricity
 - Industrial natural gas
 - Residual fuel, and
 - Other petroleum products (kerosene) and liquid gases.
- (3) The elasticities of each of the 30 fuel/sector pairs with respect to the prices of the fuels products listed in (2) above.

PIES determines supply-demand equilibrium for prices and quantities of the fuels denoted above. Using estimates of price-elasticities, the demand curve for each fuel is established through a step function approximation. For each of the fuels the price-elasticity of the predominant fuel/sector pair component is selected from an elasticity matrix. The elasticities used are for:

- (1) gasoline in transportation
- (2) household distillate fuel
- (3) household residual fuel
- (4) household kerosene
- (5) household electricity
- (6) industrial natural gas
- (7) industrial bituminous coal
- (8) metallurgical coal.

RDFOR constructs demand curves for each fuel by first computing elasticities through the use of perturbed prices and quantity responses and then combining the elasticities with unperturbed prices. Furthermore, DFACE aggregates and transforms the demand curve estimates into a format for use in PIES.

Certain fuels, e.g., metallurgical coal, are not treated in the same way as other more important fuels by RDFOR. RDFOR provides estimates of demands for these minor fuels, but the demand is then considered to be wholly elastic. Further, no interfuel substitution is permitted. These constraints are achieved within the demand model which provides estimates of zero for self and cross-price elasticities for these fuels. For example, the price of metallurgical coal is set arbitrarily at \$30/ton within the equilibrating routine and thereafter metallurgical coal is treated by the model in precisely the same way as the other price-sensitive fuels. When demand curves are calculated for these fuels, they are horizontal and quantities consumed are determined by supply.

{1}

U.S. Department of Energy, 1977 National Energy Outlook, Washington, D.C.: DOE, 1977.

{2}

Logistics Management Institute, The Integrating Mechanism of The Project Independence Evaluation System, Washington, D.C.: LMI, September 1977.

{3}

See Figure 4, Chapter II.

II. RDFOR DATA BASE

In this chapter, the data used in the RDFOR model are analyzed and documented. Quantity and price data are analyzed for the three major consuming sectors of the U.S. economy: residential, commercial, and industrial. Data used in the minor fuels (except naphthas and liquid gas) and transportation sub-models are not covered here. These data are at the national level and since these files are no longer available they cannot be replicated for documentation.

The first section analyzes historical quantity and price data for the residential, commercial, and industrial (RCI) sectors. The second section documents some of the changes that have occurred since 1977 in RDFOR, particularly in its data base. The last section documents (1) the sources of these data, (2) the macroeconomic variables used in the demand estimation, and (3) projected values used in the simulation forecasts. Historical price and quantity data by fuel/sector and by DOE region are compiled in a separate appendix to this report.

1. Data Analysis

The quantity and price data are annual time series from 1960 to 1975 for the United States and the ten DOE regions. The quantity data analyzed are in trillions of Btu and include sales of electricity, distillate, liquid gas and residual fuels; the distribution of coal; and the consumption of natural gas. In this section, all quantity data are referred to as "consumption". Prices are delivered prices including taxes in constant 1975 dollars per million Btu.

The data are analyzed for each sector using graphs, growth rates, means, and standard deviations. The graphs are time series plots of U.S. total and fuel sector quantities and prices. The U.S. total in this instance and throughout the discussion of historical data in this chapter indicates only the total of fuels modeled by RDFOR. The growth rates are average annual percentage rates, calculated by fitting a trend line over the period 1960-1975 to the logarithmic values of each fuel series. The means represent arithmetic averages for the 16-year period, and provide measures of the average magnitudes of prices and quantities. The standard deviations indicate the levels of fluctuation within fuel prices and quantities during 1960-1975.

Table 5. Department of Energy Regions

DOE Region	State	State Abbreviation	DOE Region	State	State Abbreviation
1	Connecticut	CT	6	Arkansas	AR
	Massachusetts	MA		Louisiana	LA
	Maine	ME		New Mexico	NM
	New Hampshire	NH		Oklahoma	OK
	Rhode Island	RI		Texas	TX
2	New Jersey	NJ	7	Iowa	IA
	New York	NY		Kansas	KS
				Missouri	MO
3	Delaware	DE	8	Colorado	CO
	District of			Montana	MT
	Columbia	DC		North Dakota	ND
	Maryland	MD		South Dakota	SD
	Pennsylvania	PA		Utah	UT
	Virginia	VA		Wyoming	WY
	West Virginia	WV			
4	Alabama	AL	9	Arizona	AZ
	Florida	FL		California	CA
	Georgia	GA		Hawaii	HA
	Kentucky	KY		Nevada	NV
	Mississippi	MS	10	Alaska	AK
	North Carolina	NC		Idaho	ID
	South Carolina	SC		Oregon	OR
	Tennessee	TN		Washington	WA
5	Illinois	IL			
	Indiana	IN			
	Michigan	MI			
	Minnesota	MN			
	Ohio	OH			
	Wisconsin	WI			

NOTE:

Northeast = DOE Regions 1, 2, 3
 Southeast = DOE Region 4
 Midwest = DOE Regions 5, 7
 Southwest = DOE Region 6
 Mountain = DOE Region 8
 West = DOE Region 9, 10

Figure 4. FEA REGIONS

Insert Fig. 4

Two different breakdowns of states within the United States are referenced in the analysis. One is the DOE regional breakdown shown in Table 5 and on the map in Figure 4. The other is a more general arbitrary breakdown designated in the text by name (See footnote to Table 5).

A. Energy Consumption

Consumption statistics are presented in Tables 6 through 9. Table 6 presents the growth rates by fuel/sector and by region. Tables 7, 8, and 9 present the means and standard deviations by region and by fuel for the residential, commercial, and industrial (RCI) sectors, respectively. The "Total" columns of these tables represent the sum across fuel quantities for each region.

Time series plots for the U.S. RCI total and fuel/sector quantities are presented in Figures 5 through 8. For the fuel/sector plots, petroleum products consumption is summed for each sector with the total series represented by the prefix 'PP'.

Total U.S. RCI Energy Consumption. Total RCI energy consumption in the United States increased at an average rate of 3.6 percent per year from 19,545 trillion Btu in 1960 to 29,694 trillion Btu in 1975. It showed an increasing trend from 1960 to 1973 (reaching a high of 33,029 trillion Btu in 1973) and a declining one thereafter (see Figure 5). The 1973-1975 declining trend was mainly due to the 1973 Arab oil embargo and the OPEC price increases.

The U.S. industrial sector was the largest user of energy (see Table 9). This sector consumed an average of 13,410 trillion Btu per year over the 1960-1975 period, and was the hardest hit by the 1973 oil embargo. Over 1973-1975 energy consumption in this sector declined by almost 17 percent from 16,403 trillion Btu in 1973 to 13,538 trillion Btu in 1975.

Energy consumption in the residential and commercial sectors averaged 8,652 trillion Btu and 4,944 trillion Btu, respectively, over the period. (See Tables 7 and 8.) Although affected by the 1973 embargo, the decline in consumption in these two sectors since 1973 was much less than in the industrial sector. Consumption in both sectors declined by not more than 5 percent from 1973 to 1975.

A sectoral analysis of energy consumption by fuel and region follows.

Figure 5. Time Series Plots of U.S. Total Sector Energy Consumption--1960 to 1975. (Trillions of Btu)

Insert Figure 5

Figure 6. Time Series Plots of U.S. Residential Sector Energy Consumption--1960 to 1975 (Trillions of Btu)

Insert Figure 6

U.S. Residential Sector. U.S. energy consumption in the residential sector increased at an annual rate of 3.1 percent from 6,510 trillion Btu in 1960 to 9,878 trillion Btu in 1975 (see Tables 6 and 7).

Over half of total residential consumption was in natural gas (see Figure 6), with the Midwest the largest consuming region. During the 1960-1975 period, electricity consumption increased two and one-half times as fast as total U.S. residential consumption. Although consumption of electricity after 1973 still increased, its rate of growth declined somewhat. Continuation of the increasing pattern of electricity consumption over this period was partly due to the increase in U.S. electricity reserve capacity and partly due to the increase in the nuclear share of electricity production, which is insensitive to oil price changes.

The sensitivity of U.S. energy consumption to the events following the 1973 embargo is largely reflected in the residential consumption of petroleum products, distillate and liquid gas fuels. Domestic demand declined by about 12 percent from 1973 to 1975. Average distillate sales were 2,436 trillion Btu over the 1960-1975 period. The highest average distillate sales occurred in Region 2, which was the second largest residential user of energy.

U.S. Commercial Sector. The Northeast section of the United States was the greatest commercial user of energy fuel (see Tables 6 and 8). Average consumption for Regions 2 and 5 were 860 trillion Btu and 1,112 trillion Btu, respectively. The annual rate of increase in commercial energy consumption was almost twice the annual rate of increase in residential consumption during the 1960-1975 period (see Table 6). However, energy consumption patterns in the commercial sector were quite similar to those of the residential sector (see Figure 7).

U.S. commercial consumption of electricity increased the fastest over the period at 8.4 percent per year but averaged less than natural gas consumption. For the period, natural gas consumption averaged 1,965 trillion Btu, while electricity consumption averaged 1,040 trillion Btu.

Consumption of distillate and residual fuels showed wide variation throughout the 16-year period and experienced sharp declines after 1973 as a result of the oil embargo. For the period, commercial consumption of distillate and residual fuel averaged 934 trillion Btu and 1,003 trillion Btu, respectively. The great demand for residual fuel since the mid-sixties may be in response to its demand as a source of electric power in some regions, particularly the Northwest.

Table 6. Average Annual Growth Rates in Energy Quantities by Fuel/Sector and by Region--1960 to 1975 (percent)

Fuel/Sector	DOE Region				
	1	2	3	4	5
Residential:					
Distillate	-0.05	1.2	0.7	-0.8	-0.4
Electricity	7.7	6.6	7.9	9.0	6.8
Liquid Gas	2.2	2.3	3.9	5.2	6.1
Natural Gas	4.6	3.0	2.0	3.2	3.5
Total	1.6	2.4	2.4	4.1	3.1
Commercial:					
Distillate	1.2	1.3	1.5	4.9	0.3
Electricity	9.4	8.0	8.8	9.5	7.3
Natural Gas	10.2	7.2	6.3	5.5	8.3
Residual	3.7	3.2	1.9	10.2	0.3
Total	3.7	4.1	4.4	7.1	5.5
Industrial:					
Coal	-19.2	-9.7	-2.8	0.2	-3.2
Distillate	2.9	-1.1	2.3	6.9	1.8
Electricity	4.0	2.8	5.4	4.4	5.0
Liquid Gas	9.6	9.6	9.1	4.5	2.1
Natural Gas	5.6	3.6	2.7	4.8	5.8
Residual	-0.7	-3.6	-0.8	-1.4	-2.4
Total	0.06	-1.6	0.8	3.6	2.0
Total U.S.	2.0	1.9	2.0	4.2	3.0

Table 6. Average Annual Growth Rates in Energy
Quantities by Fuel/Sector and by Region--
1960 to 1975 (percent) (Continued)

Fuel/Sector	DOE Region					
	6	7	8	9	10	U.S.
Residential:						
Distillate	8.7	-2.9	-1.1	3.0	-1.1	0.2
Electricity	9.7	6.9	6.2	8.1	6.3	7.8
Liquid Gas	2.9	4.4	4.6	0.7	4.3	4.3
Natural Gas	2.4	2.3	4.5	3.7	11.0	3.2
Total	4.2	2.5	3.9	4.3	4.7	3.1
Commercial:						
Distillate	7.7	-0.2	4.8	2.7	-1.0	1.4
Electricity	8.5	7.1	8.4	9.4	7.3	8.4
Natural Gas	6.3	6.4	5.0	5.9	12.7	6.9
Residual	19.3	1.2	-0.6	0.1	1.8	2.9
Total	7.4	5.5	5.0	6.6	4.4	5.3
Industrial:						
Coal	-0.4	-2.7	3.3	2.7	-2.2	-3.1
Distillate	5.5	7.9	7.1	5.4	7.3	4.0
Electricity	8.9	5.5	5.7	3.9	4.9	5.0
Liquid Gas	4.8	7.6	5.1	8.9	-0.5	5.4
Natural Gas	6.2	3.4	4.6	5.0	6.6	5.3
Residual	3.7	-0.02	0.2	-0.5	2.7	-0.7
Total	6.2	2.7	4.2	4.4	4.9	3.3
Total U.S.	6.0	3.2	4.3	4.8	4.8	3.6

Figure 7. *Time Series Plots of U.S. Commercial Sector Energy Consumption--1960 to 1975 (Trillions of Btu)

- (*) = Commercial Distillate Fuel (DFCMQUS) plus Residual Fuel (RFCMQS), (PPCMQUS)
- (\) = Commercial Electricity, (ELCMQUS)
- (~) = Commercial Natural Gas, (NGCMQUS)
- (@) = Commercial - All Fuels, (TTCMQUS)

*Points exceeding the scale of the graph and points where two or more variables have the same value are plotted with (\$). The variable(s) concerned are indicated on the far right hand side of the graph.

U.S. Industrial Sector. Most industrial energy was consumed in the Midwest and Southwest areas, which together accounted for over 50 percent of the nation's industrial energy consumption.

Industrial natural gas consumption averaged 7,588 trillion Btu, or 56 percent of total natural gas consumption, and increased at an annual rate of 5.3 percent from 1960 to 1975 (see Tables 6 and 9). Average consumption of natural gas in Regions 5 and 6 over the 1960-1975 period were 1,340 trillion Btu and 3,355 trillion Btu respectively. On the average, these two regions consumed the greatest amount of natural gas during the 1960-1975 period.

Industrial coal consumption declined during the 16 year period at a rate of 3.1 percent per year (see Figure 8). This was primarily due to the regulated price of interstate natural gas, the removal of import controls on residual fuel oil and its cheap imported price until the embargo, and the continued development of nuclear power. Also, over a good portion of this period, coal consumption was discouraged by the uncertainty about environmental issues and state and local air pollution regulations.

Residual fuel was the only petroleum product that showed a declining trend in industrial consumption over the 1960-1975 period. The highest average consumption of this fuel occurred in Region 5. Other regions with the highest average consumption were Region 6 for liquid gas, and Region 5 for distillate fuel.

To recapitulate, energy consumption in the United States was concentrated in the industrial sector but increased faster in the commercial sector during the 1960-1975 period. Overall, most energy was used in the Northeast section of the United States, and the fuel most used was natural gas.

Figure 8. Time Series Plots of U.S. Industrial Sector Energy Consumption--1960 to 1975 (Trillions of Btu)

Insert Fig. 8

Table 7. Residential Sector: Means and Standard Deviations
for Energy Quantities by Region and by Fuel--
1960 to 1975 (Trillions of Btu)

DOE Region	Fuel*				
	Distillate	Electricity	Liquid Gas	Natural Gas	Total**
1	410.44 (20.38)	59.32 (20.82)	12.92 (1.54)	114.79 (23.94)	597.47 (50.99)
2	610.02 (49.98)	104.86 (31.23)	14.47 (1.97)	442.54 (65.55)	1171.91 (141.50)
3	336.43 (26.13)	130.14 (46.14)	18.90 (3.47)	461.96 (48.44)	947.45 (112.33)
4	245.74 (34.44)	278.66 (110.93)	101.65 (25.72)	325.78 (52.02)	951.85 (183.59)
5	571.18 (22.88)	253.73 (78.52)	125.79 (35.07)	1453.93 (237.65)	2404.63 (340.36)
6	51.53 (21.39)	137.22 (58.97)	113.51 (19.48)	440.51 (52.69)	742.79 (144.50)
7	76.81 (10.68)	70.69 (22.22)	87.50 (18.36)	370.77 (42.71)	605.79 (71.73)
8	46.55 (7.87)	31.03 (9.17)	32.13 (7.35)	171.92 (35.21)	281.65 (49.70)
9	14.08 (3.92)	120.72 (42.88)	25.10 (3.97)	569.22 (98.01)	729.13 (143.33)
10	73.85 (7.15)	85.36 (24.80)	8.95 (2.51)	51.59 (23.48)	219.77 (46.71)
U.S.**	2436.69 (136.08)	1271.77 (445.15)	540.95 (113.59)	4403.02 (669.64)	8652.44 (1267.75)

*Figures in Parentheses are Standard Deviations.

**Total and U.S. Averages May Differ from Sum of Fuel
and Regional Averages Due to Errors in Rounding.

Table 8. Commercial Sector: Means and Standard Deviations
for Energy Quantities by Region and by Fuel--
1960 to 1975 (Trillions of Btu)

DOE Region	Fuel*				
	Distillate	Electricity	Liquid Gas	Natural Gas	Total**
1	191.00 (14.53)	45.27 (18.40)	42.10 (18.37)	219.17 (51.38)	497.56 (93.78)
2	202.24 (17.34)	120.28 (40.33)	151.72 (48.96)	386.28 (77.42)	860.53 (172.93)
3	128.17 (11.18)	102.16 (38.84)	163.50 (48.57)	155.20 (28.38)	549.05 (115.34)
4	46.20 (10.70)	154.12 (64.99)	206.65 (52.63)	30.25 (16.64)	437.23 (141.56)
5	210.30 (6.96)	194.81 (63.42)	590.25 (206.59)	117.13 (12.72)	1112.51 (274.22)
6	26.41 (14.63)	128.97 (47.68)	248.41 (76.77)	6.56 (9.90)	410.37 (134.63)
7	34.61 (2.22)	53.45 (16.98)	199.81 (58.11)	12.04 (2.27)	299.93 (74.88)
8	22.24 (5.66)	32.74 (12.18)	104.52 (23.95)	15.32 (5.54)	174.83 (41.12)
9	11.43 (4.86)	155.62 (59.66)	218.59 (57.99)	20.38 (6.31)	406.04 (118.97)
10	62.26 (5.50)	52.93 (17.76)	40.16 (21.66)	41.27 (7.01)	196.64 (41.17)
U.S.**	934.90 (68.71)	1040.39 (377.94)	1965.77 (602.76)	1003.64 (161.08)	4944.70

*Figures in Parentheses are Standard Deviations.

**Total and U.S. Averages May Differ from Sum of Fuel
and Regional Averages Due to Errors in Rounding.

Table 9. Industrial Sector: Means and Standard Deviations
for Energy Quantities by Region and by Fuel--
1960 to 1975 (Trillions of Btu)

DOE Region	Fuel*						Total**
	Coal	Dist.	Elec.	Lig. Gas	Nat. Gas	Residual	
1	27.39 (20.33)	16.47 (3.29)	55.62 (10.32)	6.74 (2.81)	45.44 (11.54)	158.27 (16.56)	309.96 (18.17)
2	187.06 (71.87)	38.64 (7.74)	131.96 (18.15)	7.21 (3.08)	181.84 (40.14)	204.43 (45.59)	751.16 (90.21)
3	513.44 (87.46)	50.53 (9.18)	198.92 (49.05)	10.33 (4.52)	485.01 (83.21)	217.49 (28.34)	1475.75 (130.25)
4	283.30 (28.86)	58.45 (20.21)	395.44 (82.69)	18.03 (4.24)	763.36 (169.71)	154.78 (25.09)	1673.38 (282.61)
5	1082.07 (196.93)	87.06 (9.83)	413.45 (96.18)	28.99 (3.51)	1340.16 (350.44)	225.22 (38.28)	3176.97 (354.00)
6	41.35 (3.07)	55.05 (20.73)	181.63 (70.56)	54.65 (13.30)	3355.86 (987.14)	46.96 (30.52)	3735.54 (1083.07)
7	102.63 (13.76)	13.93 (6.16)	64.43 (15.98)	12.04 (4.26)	374.90 (63.36)	16.81 (2.65)	584.77 (77.06)
8	37.40 (7.13)	19.08 (7.34)	34.98 (8.96)	5.99 (1.55)	242.68 (52.48)	41.88 (6.65)	382.04 (74.04)
9	3.26 (1.92)	42.77 (10.57)	144.85 (27.58)	12.66 (7.13)	655.14 (152.76)	101.04 (15.59)	959.74 (192.89)
10	25.15 (3.81)	22.97 (7.90)	120.36 (26.35)	1.94 (0.45)	159.23 (45.80)	46.53 (9.06)	376.21 (83.15)
U.S.**	2303.09 (384.78)	405.00 (82.36)	1741.68 (401.92)	158.62 (40.71)	7588.51 (1903.01)	1213.44 (86.52)	13410.40 (2154.35)

*Figures in Parentheses are Standard Deviations.

**Total and U.S. Averages May Differ from Sum of Fuel
and Regional Averages Due to Errors in Rounding.

B. Energy Prices

Price statistics are presented in Tables 10, 11, 12 and 13. Table 10 presents the average annual growth rates over the 1960-1975 period by fuel/sector and by region, including the entire U.S. Tables 11 through 13 provide the means and standard deviations for the three sectors by region and by fuel. Time series plots of fuel/sector prices are presented in Figures 9 through 12. Due to diversity in scale, consumption of electricity by the three sectors is plotted in one graph. As in the case of quantity consumption, average prices for petroleum products were calculated for each sector and are represented by the prefix 'PP'.

U.S. RCI Energy Prices. Falling domestic energy supplies and higher noncompetitive foreign prices led to substantial increases in domestic energy prices in the first half of the 1970s. Average U.S. RCI (residential, commercial, industrial) energy prices increased fastest during this period and were highest in those regions where demand was substantial and supply was limited, i.e., Northeast and West (see footnote to Table 5 for definition of these areas).

Since 1973, average real prices--particularly industrial petroleum products--increased considerably across both sectors and regions. Electricity prices in the Northeast increased by over 20 percent in the three sectors from 1973 to 1975, while natural gas prices showed only slight increases after 1973. Coal prices also increased significantly in this period, partly because of the coal strike anticipated in 1974 and partly because of the increasing demand brought about by switching from other energy sources to coal.

The trend and patterns of these energy prices across regions for each sector are examined next.

U.S. Residential Sector. Residential sector average real prices declined throughout the sixties but increased rapidly thereafter. Prices for petroleum products showed significant increase after 1973, largely because of the oil embargo. The prices for other energy fuels in the residential sector also increased after 1973; however, the rise was not as fast as for petroleum products, and these prices never reached their previous highs of the early sixties (see Figures 9 and 10).

Despite a declining trend in electricity prices over 1960-1975, they remained the highest average prices paid for energy fuels in

the residential sector. This was caused by higher fuel and operating costs as well as new provisions for capacity expansion. Electricity prices averaged as much as \$13.50/million Btu in Region 1. The lowest average electricity price of \$5.42/million Btu in Region 10 was still twice as much as the average U.S. prices paid for other residential fuels (see Table 11).

Natural gas price reversed its declining trend in 1970. This could be partially attributed to declining total supplies and the shifting of new gas supplies to the unregulated intrastate market. Over the 1960-1975 period the average real price of natural gas in the U.S. was \$1.64/million Btu. In Region 1 average prices were as much as \$3.02/million Btu.

Average real prices of petroleum products increased at an annual rate of 1.4 percent over 1960 to 1975 and showed wide variation throughout this period. The most significant increases occurred from 1973 to 1975, when average real prices for distillate and liquid gas fuels both increased by over 30 percent. Over the 1960-1975 period, real prices for each of these two fuels averaged around \$2.00/million Btu across all regions.

U.S. Commercial Sector. Commercial real prices of energy showed a pattern similar to that of the residential sector. The highest average energy prices paid by the commercial sector during 1960-1975 occurred in the Northeast, with the highest average electricity prices in Region 2--\$13.20/million Btu and \$12.65/million Btu, respectively (see Table 12).

Real prices of electricity began to increase in 1970 after the steady decline throughout the sixties. They showed a slight decline in 1972, which could be attributed to the increase in the nuclear share of electricity production which was almost 100 percent higher in 1973 than it was in 1972.

Commercial natural gas prices rose faster than residential natural gas prices during the early seventies. The big rise in real natural gas prices in 1974 and 1975 was partially due to a significant decline in supply during this period. Over the 1960-1975 period natural gas real prices averaged \$1.16/million Btu and were highest in Region 1.

U.S. commercial residual fuel prices increased two and one-half times faster than commercial distillate prices over the 1960-1975 period. Residual fuel prices averaged \$1.11/million Btu, while distillate prices averaged \$1.77/million Btu for the period. The commercial sectors of the Western states were affected most by the higher oil prices experienced in 1973. In these states the prices for residual and distillate fuels averaged around \$1.34/million Btu and \$1.80 million Btu respectively.

Figure 9. Time Series Plots of U.S. Electricity Prices
for the Residential, Commercial and Industrial
Sectors--1960 to 1975 (Dollars per Million Btu)

Insert Fig. 9

Figure 10. *Time Series Plots of U.S. Residential Sector
Energy Prices--1960 to 1975 (Dollars per Million Btu)

Figure 11. Time Series Plots of U.S. Commercial Sector
Energy Prices--1960 to 1975 (Dollars per Million Btu)

Insert Fig. 11

Figure 12. *Time Series Plots of U.S. Industrial Sector Energy Prices
over the Period--1960 to 1975 (Dollars per Million Btu)

- (*) = Average Price of Industrial Distillate Fuel Oil, (DFINPUS), Industrial Liquid Gases, (LGINPUS), and Industrial Residual Fuel Oil, (RFINPUS), All (PPINPUS)
- (~) = Industrial Natural Gas, (NGINPUS)
- (#) = Industrial Coal, (CLINPUS)

Insert Fig. 12

U.S. Industrial Sector. Compared with the other sectors, U.S. industrial coal and petroleum prices increased at the fastest rates over the 1960-1975 period (see Table 10). For the period, coal and average petroleum products prices increased at a rate of roughly 3 percent most regions. Average industrial electricity prices were the only prices that showed an overall decline over the 1960-1975 period.

Regions 1 and 2 had the highest average industrial prices for electricity, liquid gas and natural gas, while Region 9 had the highest average prices for distillate and residual fuels (see Table 13). Coal prices averaged \$.53/million Btu in the U.S. and reached \$.92/million Btu in Region 6.

To recapitulate, in the U.S. the highest energy prices paid were in the residential sector. The highest average energy prices were for electricity, and the lowest average prices were for industrial coal. For all sectors over 1960-1975, Northeast consumers paid the highest average price.

Table 10. Average Annual Growth Rates in Energy Prices
by Fuel/Sector and by Region--1960 to 1975
(Percent)

Fuel/Sector	DOE Region				
	1	2	3	4	5
Residential:					
Distillate	1.6	1.7	1.7	1.3	1.0
Electricity	-2.9	-1.7	-2.5	-2.5	-3.3
Liquid Gas	0.3	0.5	1.2	2.6	0.4
Natural Gas	-1.8	-2.1	-1.2	-1.7	-1.5
Commercial:					
Distillate	1.7	1.7	1.7	1.0	1.1
Electricity	-3.3	-1.0	-2.5	-3.2	-3.1
Natural Gas	-1.7	-2.2	-1.2	-0.3	-1.2
Residual	4.3	3.4	5.1	4.5	3.2
Industrial:					
Coal	2.8	2.9	2.9	3.6	2.6
Distillate	2.0	1.9	1.9	1.2	1.4
Electricity	-0.7	0.3	-0.1	1.6	-0.5
Liquid Gas	0.5	0.8	1.3	2.7	0.8
Natural Gas	-0.3	-1.5	-0.3	-0.01	-0.08
Residual	4.5	4.1	5.0	4.7	3.3

Table 10. Average Annual Growth Rates in Energy
Prices by Fuel/Sector and by Region--
1960 to 1975 (Percent) (Continued)

Fuel/Sector	DOE Region					
	6	7	8	9	10	U.S.
Residential:						
Distillate	1.6	1.0	1.1	0.8	0.8	1.4
Electricity	-4.8	-4.0	-4.0	-3.0	-3.5	-3.1
Liquid Gas	3.6	0.5	0.5	0.6	0.5	1.4
Natural Gas	-0.7	-0.8	-1.0	-1.6	-2.2	-1.4
Commercial:						
Distillate	1.6	1.1	1.2	1.2	1.1	1.4
Electricity	-4.0	-3.9	-4.4	-3.0	-4.0	-2.9
Natural Gas	0.9	-0.2	-0.02	-0.5	-2.9	-0.8
Residual	3.6	3.5	2.3	2.4	2.2	3.5
Industrial:						
Coal	2.8	4.3	2.0	3.6	1.8	2.8
Distillate	2.0	1.4	1.3	1.4	1.3	1.6
Electricity	-2.6	-1.6	-2.5	-1.0	-2.1	-0.4
Liquid Gas	4.1	0.8	1.1	1.2	1.1	2.2
Natural Gas	3.1	-0.9	0.3	-0.07	1.0	0.5
Residual	4.5	3.7	2.5	2.6	2.5	3.8

Table 11. Residential Sector: Means and Standard Deviations for Energy Prices by Region and by Fuel--
1960 to 1975 (Dollars per Million Btu in Constant 1975 Dollars)

DOE Region	Fuel*			
	Distillate	Electricity	Liquid Gas	Natural Gas
1	2.04 (0.36)	13.50 (2.21)	2.24 (0.42)	3.02 (0.34)
2	2.03 (0.32)	13.90 (1.71)	2.20 (0.31)	2.45 (0.30)
3	1.97 (0.32)	11.15 (1.66)	1.99 (0.38)	1.88 (0.14)
4	1.97 (0.31)	8.14 (1.15)	1.65 (0.45)	1.63 (0.15)
5	1.91 (0.31)	11.26 (1.82)	1.80 (0.27)	1.52 (0.13)
6	1.88 (0.33)	10.67 (2.39)	1.51 (0.40)	1.26 (0.06)
7	1.90 (0.31)	11.54 (2.14)	1.75 (0.28)	1.27 (0.06)
8	2.02 (0.31)	11.21 (2.08)	1.99 (0.28)	1.15 (0.06)
9	2.24 (0.30)	10.51 (1.69)	2.12 (0.30)	1.52 (0.15)
10	2.23 (0.25)	5.42 (0.87)	2.11 (0.28)	2.22 (0.25)
U.S.	1.99 (0.32)	10.38 (1.65)	1.76 (0.32)	1.64 (0.13)

*Figures in Parentheses are Standard Deviations.

Table 12. Commercial Sector: Means and Standard Deviations
for Energy Prices by Region and by Fuel--
1960 to 1975 (Dollars per Million Btu in Constant
1975 Dollars)

DOE Region	Fuel*			
	Distillate	Electricity	Natural Gas	Residual
1	1.78 (0.34)	13.20 (2.53)	2.35 (0.27)	1.05 (0.48)
2	1.79 (0.31)	12.65 (1.70)	1.97 (0.26)	1.12 (0.42)
3	1.76 (0.32)	10.00 (1.56)	1.47 (0.13)	0.99 (0.47)
4	1.77 (0.27)	8.92 (1.52)	1.09 (0.05)	0.88 (0.39)
5	1.71 (0.32)	10.52 (1.65)	1.19 (0.10)	1.27 (0.44)
6	1.65 (0.33)	8.42 (1.65)	0.68 (0.07)	0.95 (0.35)
7	1.72 (0.32)	10.20 (1.90)	0.87 (0.05)	1.22 (0.46)
8	1.84 (0.33)	9.30 (1.90)	0.85 (0.05)	1.34 (0.42)
9	1.89 (0.33)	8.46 (1.49)	1.06 (0.08)	1.35 (0.44)
10	1.89 (0.32)	5.84 (1.14)	1.67 (0.25)	1.34 (0.42)
U.S.	1.77 (0.32)	9.73 (1.55)	1.16 (0.08)	1.11 (0.43)

*Figures in Parentheses are Standard Deviations.

Table 13. Industrial Sector: Means and Standard Deviations
for Energy Prices by Region and by Fuel--
1960 to 1975 (Dollars per Million Btu in
Constant 1975 Dollars)

DOE Region	Fuel*					
	Coal	Dist.	Elec.	Liq. Gas	Nat. Gas	Residual
1	0.73 (0.16)	1.90 (0.31)	7.93 (0.87)	2.08 (0.31)	1.70 (0.22)	1.10 (0.46)
2	0.59 (0.14)	1.90 (0.27)	6.21 (0.78)	2.06 (0.25)	1.27 (0.17)	1.16 (0.41)
3	0.47 (0.10)	1.86 (0.27)	5.79 (0.66)	1.94 (0.29)	0.96 (0.06)	1.05 (0.43)
4	0.50 (0.13)	1.89 (0.22)	3.76 (0.44)	1.57 (0.38)	0.68 (0.06)	0.93 (0.38)
5	0.53 (0.12)	1.81 (0.27)	5.34 (0.26)	1.72 (0.23)	0.86 (0.07)	1.33 (0.40)
6	0.92 (0.25)	1.73 (0.29)	4.43 (0.60)	1.39 (0.37)	0.37 (0.10)	0.98 (0.36)
7	0.61 (0.19)	1.82 (0.27)	5.98 (0.50)	1.67 (0.24)	0.58 (0.06)	1.28 (0.42)
8	0.49 (0.11)	1.99 (0.27)	4.21 (0.51)	1.84 (0.25)	0.46 (0.43)	1.39 (0.38)
9	0.66 (0.28)	2.02 (0.28)	5.25 (0.64)	1.91 (0.27)	0.70 (0.12)	1.43 (0.40)
10	0.45 (0.18)	2.01 (0.26)	1.83 (0.20)	1.91 (0.25)	0.72 (0.88)	1.42 (0.39)
U.S.	0.53 (0.13)	1.87 (0.27)	4.83 (0.35)	1.65 (0.31)	0.60 (0.07)	1.17 (0.40)

*Figures in Parentheses are Standard Deviations.

2. Data Updates

This section documents some of the changes that have occurred since 1977 in the Regional Demand Forecasting Model (RDFOR). Subsection A presents an overview of all these changes. Subsection B discusses and documents new changes in the data base. A detailed description of the techniques used to obtain and/or update new estimates of data, as well as the sources of these data, are included in this section. A discussion of other changes, i.e., recent modifications to the structure of the model, the estimation procedure utilized and the empirical results obtained, are covered in Subsection 3.F of the following chapter.

A. An Overview of Updates

Due to a requirement to prepare new forecasts for the Director's Report to Congress, it was necessary to update the 1977 version of the RDFOR model. Such updating mostly involved changes in the following:

- Benchmarking procedure
- Data base
- Equation structure
- Estimation procedure, and
- Forecast of macro variables.

New benchmarking was inevitable for the Director's Report. It was necessary to benchmark the model to 1977 data. However, data were, in most cases, only available through 1975. This necessitated estimating the missing data.

Initial "quantities" data were estimated by using growth rates of fuel aggregates obtained from DOE's short-run models. The data were then shared out into sub-categories. Some initial monthly "price" data were available through mid-1977. Price data not available were also estimated.

Another aspect of data revision involved correcting some known errors in the existing data base. These corrections mostly involved distillate fuel in the residential sector and all fuels in the industrial sector. The affected equations due to these data corrections were re-estimated and the new coefficients obtained were substituted for the old ones. The equation structures in these instances remained the same.

There were also a few re-estimations as well as changes in the equation structure due to the availability of new and/or more disaggregated data. New data were obtained for the jet fuel equations and these equations were re-estimated. Industrial

naptha was broken out of the liquid gas minor fuels equation and these two new equations were estimated. These modifications are discussed in the next chapter.

The new RDFOR forecasts were based on new macro forecasts obtained from Data Resources, Inc. Heating/cooling degree days and refinery consumption data were also updated.

B. New Data Base

This section describes the techniques used to update initial quantity, initial price, and macro data needed to prepare new forecasts for the Director's Report to Congress. These new forecasts were benchmarked to 1977. However, much of the data were not available past 1975 and had to be estimated.

Initial Quantities Data. Initial quantities data were based, whenever possible, on the forecasts of the short-run forecasting models within DOE. Data on natural gas and petroleum products were estimated using short-run forecasts of DOE forecasting demand models for natural gas and petroleum products, respectively. Coal and electricity data were estimated using the results of the short-term National Coal Model{1}.

The techniques used to forecast the data for 1976 and 1977 are described below.

The ten fuel aggregates forecast by the short-run models (SR aggregates hereafter) were:

1. ELTT (Electricity Total)
2. NGRS (Natural Gas Residential)
3. NGCM (Natural Gas Commercial)
4. NGIN (Natural Gas Industrial)
5. DFTT (Distillate Fuel Total)
6. RFTT (Residual Fuel Total)
7. OPTT (Other Petroleum Total)
8. GSTR (Gasoline Transportation)
9. CLRI (Retail/Industrial Coal)
10. MCIN (Metallurgical Coal)

These ten fuels had to be broken down into the thirty fuel/sector combinations used by RDFOR. Corresponding to the ten SR aggregates were forecasts of ten annual regional growth rates by the short-run models. A description on how the 30 fuel/sector combinations were derived from the SR aggregates and their corresponding SR growth rates are given below.

- (1) To keep the new estimates consistent with the RDFOR data base, corresponding SR aggregates were formed in the long-run model by adding sub-categories of RDFOR fuels.
- (2) The historical aggregate data in the long-run model were grown at the growth rates forecast by the short-run models for 75-76 and 76-77.
- (3) Shares for the 76 and 77 forecast years were formed for each of the 25 sub-categories in the long-run model by dividing the fuel sub-categories by their corresponding SR aggregates (e.g., forecast LR residential distillate (1976)/forecast LR total distillate (1976)).
- (4) These shares were used to share out the adjusted totals generated in (2) above.

This is equivalent to imposing RDFOR sectoral distribution forecast upon the SR aggregates from the short-run models. The RDFOR growth rate is thus (1) equal to the growth rate forecast by the short-run models for fuel aggregates, and (2) consistent with the 1975 historical data used in the long-run model.

Estimates of regional growth rates forecast by the short-run models for the ten aggregate fuels are given in Tables 14 and 15.

Table 16 contains national quantities and quantity growth rates for selected fuel aggregates for 1975-1977.

Initial Prices Data. Initial price data for 1976 and 1977 came from many diverse sources. Some of the data were available for these years but others had to be estimated from 1975 prices from the Federal Energy Data System (FEDS) historical data base plus regionally (and fuel) specific growth rates.

Electricity. Electricity prices for 1976 were derived from average revenue data available in Edison Electric, 1976 Statistical Yearbook {2}. Average revenue data for 1977 were not available and had to be generated by applying some growth rates to the 76 figures. State-by-state growth rates in typical monthly electric bills were chosen for this purpose. These rates were available from Federal Power Commission, Typical Electric Bills, 1977{3}. The 77 average revenue data used were for 500KWH "residential" service, 4,000 KWH-10,000 KWH "commercial" service, and 10,000 KWH-20,000 KWH "industrial" services.

Table 14. Growth Rates in Quantities by Region
1975-1976

Fuel/Sector Code	DOE Region				
	1	2	3	4	5
ELTT	.085	.028	.076	.079	.054
NGRS	.047	.019	.027	.051	.022
NGCM	.040	.027	.028	.027	.034
NGIN	.052	.047	.030	.027	.000
DFTT	.124	.124	.124	.094	.132
RFTT	.125	.125	.125	.141	.123
OPTT	.039	.019	.041	.026	.050
GSTR	.078	.078	.078	.037	.053
CLRI	-.327	.090	-.057	-.061	-.041
MCIN	.000	.477	.066	-.063	-.087

Table 14. Growth Rates in Quantities by Region
1975-1976 (Continued)

Fuel/Sector Code	DOE Region				
	6	7	8	9	10
ELTT	.052	.049	.151	.004	.094
NGRS	.059	.020	.050	.010	.050
NGCM	.014	.010	-.004	-.030	-.040
NGIN	.045	.002	-.020	.018	.003
DFTT	-.007	.132	.074	.159	.117
RFTT	.216	.123	.119	.193	.189
OPTT	.048	.042	.145	.052	.077
GSTR	-.033	.053	.061	.067	.068
CLRI	.183	.167	.149	1.341	.247
MCIN	-.357	.040	.007	.024	.000

Table 15. Growth Rates in Energy Quantities by Region
1976-1977

Fuel/Sector Code	DOE Region				
	1	2	3	4	5
ELTT	.007	.049	.052	.071	.046
NGRS	.032	.008	.015	.050	.011
NGCM	.032	.001	.021	.026	.017
NGIN	.042	.027	.029	.027	.003
DFTT	.051	.051	.051	.071	.112
RFTT	.036	.036	.036	.065	.040
OPTT	.065	.063	.049	.044	.049
GSTR	.012	.012	.012	.032	.025
CLRI	-.128	-.068	.001	.118	.019
MCIN	.000	-.202	-.068	.005	.032

Table 15. Growth Rates in Energy Quantities by Region
1976-1977 (Continued)

Fuel/Sector Code	DOE Region				
	6	7	8	9	10
ELTT	.079	.077	.148	.004	.094
NGRS	.059	.024	.004	.009	.005
NGCM	.008	.006	-.004	-.020	-.043
NGIN	.036	.002	-.021	.022	.004
DFTT	.080	.112	.067	.033	.033
RFTT	.178	-.040	-.035	.103	.096
OPTT	.072	.059	.122	.017	.051
GSTR	.065	.025	.019	.016	.015
CLRI	.147	.015	.416	.191	.117
MCIN	.123	.035	-.066	-.012	.000

Table 16. National Quantities and Quantity Growth Rates
For Selected Fuel Aggregates
1975-1977

Fuel	Fuel/ Sector Code	Quantities (Trillion BTU)			Growth Rates (Percent)	
		1975	1976	1977	75-76	76-77
Electricity	ELTT	5913	6267	6631	6.0	5.8
Natural Gas	NGTT	16583	17010	17343	2.6	2.0
Distillate Fuel	DFTT	6029	6673	7147	10.7	7.1
Residual	RFTT	2769	3179	3397	14.8	6.9
Liquid Gas ^{1/}	LGTT	1053	1167	1260	10.8	8.0
Coal	CLTT	3860	3809	3916	-1.3	2.8
Gasoline	GSTR	13029	13652	14007	4.8	2.6
Jet Fuel	JRTR	1809	1782	1793	-1.5	0.6
Other Petroleum Products	OPTT	3109	3223	3392	3.7	5.2
Total ^{2/}	TTIT	54154	57872	58886	4.7	3.7
Residential	TTRS	10052	10451	10792	4.0	3.3
Commercial	TTCM	7288	7537	7702	3.4	2.2
Industrial	TTIN	18860	2001.4	21001	6.1	4.9
Transportation	TTTR	17954	18760	19391	4.5	3.4

^{1/} Excludes feedstocks.

^{2/} Total does not include industrial still gas, industrial petroleum coke, natural gas, pipeline fuel and utility fuel.

Natural Gas. Natural gas prices for 1976 were based upon regional/sectoral growth rates from 1975-1976 in average revenue data from the American Gas Association's Gas Facts{4}. These growth rates were applied to 1975 average revenue data from the Bureau of Mines in the FEDS data base. Since there were significant differences in average price data for natural gas from AGA and BOM, the 1976 Gas Facts data had to be somewhat modified. The 1977 data for natural gas was obtained through an interpolation between estimated 1976 price data and 1985 natural gas prices from the Project Independence Evaluation System (PIES) runs.

A note on the right concept of regional "price" for natural gas is in order. The relevant price for industrial decision making in regions dominated by intrastate markets is the new contract price of intrastate gas. The inconsistency between the average revenue data for the historical end-point of the RDFOR price trajectories and the PIES equilibrium prices for 1985 produces exceptionally steep price paths in Region 6, which drives industrial gas consumption down by almost a quad. The PIES 1985 price is the average well head price plus \$.10 distribution charge to the industrial sector. It is assumed that all old contracts have rolled over by 1985 so no credit is given to account for marginal to average differences. The price of industrial gas has been changed to \$1.73 in Region 6 and 9 for 1977 to account for the marginal to average price differences. This price is more representative of the marginal price to industrial users in those regions. The 1975 price for industrial gas in Region 6 was also changed to \$1.20.

Coal. No data were available on estimated rates of growth in coal prices over the period 1975-1977, so coal prices for the years 1976 and 1977 were interpolations between 1975 prices from the FEDS historical data base and 1985 coal prices from last year's PIES runs.

Oil. Gasoline, distillate oil, residual oil, and kerosene (jet fuel) prices for 1975-1977 were based upon actual prices available for 1975-1976, and the first seven months of 1977. Gasoline prices were from Platt's Oilmanac{5} and Lundberg Survey, Inc.{6}. Distillate oil, residual oil and kerosene prices were from Platt's Oilmanac.

Liquid gas prices were estimated using growth rates in wholesale propane prices over the period 1975-1977. These rates were obtained from the DOE short-term petroleum model. Constant 1975 retailer markups from the FEDS data base were applied to the estimated wholesale liquid gas prices.

The following four tables summarize the 1976 and 1977 estimates of fuel prices which were used in RDFOR. Table 17 shows the estimates for fuel/sectoral national prices and price growth

rates for 1975-1977. Tables 18 through 20 show the complete fuel/sectoral detail of the regional prices used in RDFOR.

Table 17. National Prices and Price Growth Rates
by Fuel Sector

Sector	Fuel	Fuel Sector Code	Prices (1975 Dollars/MMB)			Growth Rate (Percent)	
			1975	1976	1977	75-76	76-77
Residential	Electricity	ELRS	9.402	9.547	9.780	1.5	2.4
	Natural Gas	NGRS	1.655	1.821	1.900	10.0	4.3
	Distillate	DFRS	2.700	2.720	2.930	0.7	7.7
	Liquid Gas	LGRS	2.480	2.580	2.600	4.0	0.8
Commercial	Electricity	ELCM	9.251	9.490	9.790	2.6	3.2
	Natural Gas	NGCM	1.308	1.488	1.580	13.8	6.2
	Distillate	DFCM	2.430	2.320	2.450	-4.5	5.6
	Residual	DFCM	2.010	1.850	2.020	-8.0	9.2
Industrial	Electricity	ELIN	5.630	5.654	5.940	0.4	5.1
	Natural Gas	NGIN	1.080	1.390	1.510	29.0	15.0
	Distillate	DFIN	2.420	2.310	2.420	-4.5	4.8
	Residual	RFIN	1.920	1.740	1.910	-9.4	9.8
	Liquid Gas	LGIN	2.340	2.420	2.430	4.3	0.4
	Coal	CLIN	.889				
Transport- tation	gasoline	GSTR	4.580	4.390	4.380	-4.1	-0.2
	Distillate (Diesel)	DFTR	3.410	3.320	3.410	-2.6	2.7
	Jet Fuel	JFTR	3.370	3.260	3.380	3.3	3.7
	Residual	RFTR	1.780	1.630	1.780	-8.4	9.2

Table 18. Estimated 1975 Prices for Fuel/Sector by Region
(Dollars per Million BTU in Constant 1975 Dollars)

Fuel/Sector Code	DOE Region					
	1	2	3	4	5	6
ELRSP	13.21	14.84	11.13	8.19	9.69	7.91
NGRSP	3.06	2.50	1.93	1.49	1.53	1.35
DFRSP	2.81	2.77	2.68	2.63	2.57	2.50
LGRSP	3.75	2.93	2.64	2.49	2.86	2.43
ELCMP	12.86	14.92	10.35	8.58	9.48	6.91
NGCMP	2.54	2.03	1.65	1.18	1.29	.91
DFCMP	2.48	2.50	2.42	2.38	2.34	2.38
RFCMP	2.21	2.03	2.06	1.89	2.07	1.63
ELINP	9.41	8.08	7.29	5.28	5.87	4.24
NGINP	2.14	1.51	1.08	.83	1.07	1.20
DFINP	2.48	2.50	2.42	2.88	2.34	2.88
RFINP	2.21	2.03	2.06	1.89	2.07	1.63
LGINP	2.83	2.65	2.49	2.30	2.22	2.25
CLINP	1.15	.96	.74	.88	.88	1.70
GSTRP	4.55	4.66	4.54	4.47	4.66	4.46
JFTRP	3.04	2.99	2.99	2.82	2.73	2.71
DFTRP	3.45	3.47	3.39	3.35	3.31	3.35
RFTRP	2.21	2.03	2.06	1.89	2.07	1.63

Table 18. Estimated 1975 Prices for Fuel/Sector by Region
 (Dollars per Million BTU in Constant 1975 Dollars)
 (Continued)

Fuel/Sector Code	DOE Region				
	7	8	9	10	US
ELRSP	8.90	8.20	9.85	4.24	9.40
NGRSP	1.30	1.17	1.53	2.09	1.66
DFRSP	2.59	2.83	2.83	2.80	2.70
LGRSP	2.83	2.61	2.79	2.70	2.48
ELCMP	8.26	6.89	8.29	4.44	9.25
NGCMP	.97	.98	1.25	1.57	1.31
DFCMP	2.32	2.52	2.50	2.50	2.43
RFCMP	1.89	1.56	1.56	1.56	2.01
ELINP	5.67	3.72	6.33	1.64	5.63
NGINP	.67	.60	.99	1.04	1.08
DFINP	2.32	2.52	2.50	2.50	2.42
RFINP	1.89	1.56	1.56	1.56	1.92
LGINP	2.22	2.43	2.56	2.49	2.34
CLINP	1.09	.83	1.64	.97	.89
GSTRP	4.63	4.66	4.68	4.58	4.58
JFTRP	2.81	3.05	3.02	3.02	3.37
DFTRP	3.29	3.49	3.47	3.47	3.41
RFTRP	1.89	1.56	1.56	1.56	1.78

Table 19. Estimated 1976 Prices for Fuel/Sector by Region
(Dollars per Million BTU in Constant 1975 Dollars)

Fuel/Sector Code	DOE Region					
	1	2	3	4	5	6
ELRSP	12.63	14.91	10.65	8.48	9.87	8.55
NGRSP	3.32	2.78	2.07	1.56	1.69	1.66
DFRSP	2.84	2.77	2.70	2.66	2.61	2.36
LGRSP	3.30	2.98	2.68	2.56	2.49	2.51
ELCMP	12.23	14.74	10.38	8.48	9.70	7.57
NGCMP	3.10	2.17	1.82	1.81	1.47	1.17
DFCMP	2.39	2.39	2.23	2.23	2.23	2.23
RFCMP	1.99	1.91	1.89	1.79	1.85	1.45
ELINP	8.91	7.60	6.82	5.66	5.70	4.81
NGINP	2.25	1.77	1.16	1.00	1.27	1.63
DFINP	2.39	2.39	2.23	2.23	2.23	2.23
RFINP	1.99	1.91	1.89	1.79	1.85	1.45
LGINP	2.88	2.69	2.53	2.37	2.35	2.33
CLINP	1.20	1.01	.80	.94	.93	1.66
GSTRP	4.44	4.86	4.45	4.42	4.40	4.14
JFTRP	3.04	2.96	2.96	2.82	2.75	2.55
DFTRP	3.36	3.36	3.20	3.20	3.20	3.20
RFTRP	1.99	1.91	1.89	1.79	1.85	1.45

Table 19. Estimated 1976 Prices for Fuel/Sector by Region
 (Dollars per Million BTU in Constant 1975 Dollars)
 (Continued)

Fuel/Sector Code	DOE Region				
	7	8	9	10	US
ELRSP	9.51	8.47	9.87	4.28	9.55
NGRSP	1.41	1.35	1.59	2.37	1.82
DFRSP	2.60	2.79	2.79	2.96	2.72
LGRSP	2.51	2.73	2.70	2.71	2.58
ELCMP	8.77	7.05	9.35	4.87	8.49
NGCMP	1.08	1.09	1.42	1.84	1.49
DFCMP	2.23	2.50	2.50	2.50	2.32
RFCMP	1.69	1.43	1.43	1.43	1.85
ELINP	5.93	2.91	6.67	1.66	5.65
NGINP	.83	.75	1.80	1.28	1.39
DFINP	2.23	2.50	2.50	2.50	2.31
RFINP	1.69	1.43	1.43	1.43	1.74
LGINP	2.35	2.55	2.47	2.50	2.42
CLINP	1.12	.86	1.62	1.01	.95
GSTRP	4.31	4.39	4.56	4.44	4.39
JFTRP	2.79	2.98	3.16	3.16	3.26
DFTRP	3.20	3.47	3.47	3.47	3.32
RFTRP	1.69	1.43	1.43	1.43	1.63

Table 20. Estimated 1977 Prices for Fuel/Sector by Region
(Dollars per Million BTU in Constant 1975 Dollars)

Fuel/Sector Code	DOE Region					
	1	2	3	4	5	6
ELRSP	12.39	15.01	10.94	8.62	10.45	9.13
NGRSP	3.37	2.85	2.16	1.65	1.77	1.69
DFRSP	2.99	2.99	2.88	2.84	2.88	2.84
LGRSP	3.35	3.03	2.73	2.59	2.50	2.54
ELCMP	12.06	15.92	10.69	8.68	10.20	8.07
NGCMP	3.12	2.25	1.90	1.39	1.54	1.25
DFCMP	2.53	2.53	2.41	2.36	2.41	2.36
RFCMP	2.19	2.07	2.07	2.01	2.01	1.57
ELINP	8.79	8.05	7.06	5.88	6.17	5.80
NGINP	2.30	1.83	1.25	1.08	1.39	1.73
DFINP	2.53	2.53	2.41	2.36	2.41	2.36
RFINP	2.19	2.07	2.07	2.01	2.01	1.57
LGINP	2.93	2.74	2.58	2.40	2.36	2.36
CLINP	1.25	1.06	.85	1.00	.98	1.62
GSTRP	4.41	4.31	4.46	4.42	4.40	4.16
JFTRP	3.14	3.14	3.04	2.99	3.04	2.99
DFTRP	3.50	3.50	3.38	3.36	3.38	3.33
RFTRP	2.19	2.07	2.07	2.01	2.01	1.57

Table 20. Estimated 1977 Prices for Fuel/Sector by Region
(Dollars per Million BTU in Constant 1975 Dollars)
(Continued)

Fuel/Sector Code	DOE Region				
	7	8	9	10	US
ELRSP	10.04	9.81	9.62	4.53	9.81
NGRSP	1.45	1.37	1.73	2.44	1.90
DFRSP	2.88	2.97	2.97	2.97	2.93
LGRSP	2.52	2.74	2.67	2.69	2.66
ELCMP	9.06	6.95	9.30	4.81	9.79
NGCMP	1.21	1.20	1.54	1.91	1.58
DFCMP	2.41	2.45	2.45	2.45	2.45
RFCMP	1.86	1.59	1.59	1.59	2.02
ELINP	6.33	2.88	6.66	1.69	5.94
NGINP	.95	.84	1.73	1.34	1.51
DFINP	2.41	2.45	2.45	2.45	2.42
RFINP	1.86	1.59	1.59	1.59	1.91
LGINP	2.36	2.56	2.44	2.48	2.43
CLINP	1.15	.89	1.60	1.05	1.00
GSTRP	4.31	4.38	4.53	4.44	4.38
JFTRP	3.04	3.12	3.12	3.12	3.38
DFTRP	3.38	3.42	3.42	3.42	3.41
RFTRP	1.86	1.59	1.59	1.59	1.78

Naptha and Liquid Gas Data. Estimation of separate equations for industrial naphthas and liquid gas feedstocks required new data on these materials. These data were available at the national level by the Bureau of Mines, and at the state level by Synergy, Inc. The methodology used by Synergy in sharing out the national data is described below.

Industrial Naptha. The national data were shared out to states by the productive capacities of refineries which consume naphthas. The data were available for individual refineries from World Naptha Survey, 1976{7}. The primary uses of naphthas, i.e., in etnylene, aromatics and SWG production, were included in the state shares computed by Synergy.

Liquid Gas Feedstocks. Liquid gas feedstocks include raw materials usages of LPG and LRG, raw materials still gas, and miscellaneous raw materials. Synergy shared out LPG and LRG by using the IR&T data on consumption of ethane and propane for petrochemical uses{8}. Ethane and propane cover about 90% of LPG + LRG for petrochemical feedstocks. Most of the remaining portion is butane which is assumed to be used by the same petrochemical manufacturers.

Still gas raw materials and miscellaneous raw materials were shared out by Synergy using the same shares.

Macro Data. This section describes the update of heating/cooling degree day data and the update of refinery fuel consumption.

Heating/Cooling Degree Days. The 1976 heating/cooling degree day data were from the National Oceanic and Atmospheric Administration. It was weighted by current population to arrive at DOE regional totals. The 1977 data were from Data Resources and complete only through June, and in some cases, July. Thirty-year average temperatures were assumed in the months for which data were not available. No data were available for the District of Columbia, Alaska, and Hawaii, so these states were left out of the population weighted regional totals.

Refinery Consumption. Fuels burned by refineries were not modeled in the Regional Demand Forecasting Model (RDFOR) since they were included in the PIES Refinery Model. This necessitated that refinery consumption be subtracted from demand model initial quantities to avoid double counting of these fuels.

Previously RDFOR was benchmarked for 1975 with 1974 refinery consumption data. Following the same procedure then required the 75 and 76 data only. Preliminary data are now available through 1976 in Tables 24 and 25 of the Bureau of Mines Petroleum Statement{9}. Some states are listed in groups for disclosure reasons. Where states from more than one region were grouped together, 1977 refinery capacity by state was used to share out the data.

4

2. Data Sources

This section documents the sources of (1) the price and quantity data analyzed in the previous section and (2) the macroeconomic variables used in the three sectors of the RDFOR Model. Also included in this section is a brief discussion of the projected data used in the forecast simulations of the RDFOR Model.

All historical data on prices, quantities and macroeconomic variables are compiled from published sources. The principal sources of the first two groups are listed in Tables 14 and 15. The macroeconomic variables include (1) disposable income, used in the demand equations for the residential and commercial sectors; (2) value added in manufacturing, used in the industrial sector; (3) heating degree days, cooling degree days, gas service customers and population. The sources of these data are displayed in Table 16.

Projected data include forecasts of prices, quantities and macro economic variables. Initial price and quantity estimates are discussed in detail in Chapter 4. Projections for some of the macroeconomic variables, i.e. population, income and value added, were obtained from the DRI model. The weather variables--heating degree days and cooling degree days--were projected to maintain their average historical values.

Table 21. Price Data Sources

Fuel	Fuel Abbreviation	Data Source
Coal	CL	U.S. Department of Commerce, "Fuels and Electric Supplement," <u>Annual Survey of Manufacturers.</u> Data Resources Inc., <u>National Coal Price Series.</u>
Distillate	DF	Platts Oilgram Service. Foster Associates, <u>Energy Prices, 1960-1973.</u> Federal Energy Administration, <u>Monthly Energy Review,</u> March 1976.
Electricity	EL	Edison Electric Institute, <u>Statistical Yearbook.</u> Federal Energy Administration, <u>Monthly Energy Review,</u> March 1976.
Liquid Gas	LG	Platts Oilgram Service. Foster Associates, <u>Energy Prices, 1960-1973.</u> Federal Energy Administration, <u>Monthly Energy Review,</u> March 1976.
Natural Gas	NG	U.S. Bureau of Mines, <u>Minerals Industrial Survey.</u>
Residual	RF	Platts Oilgram Service. Foster Associates, <u>Energy Prices, 1960-1973.</u> Federal Energy Administration, <u>Monthly Energy Review,</u> March 1976.

Table 22. Quantities Data Sources

Fuel	Fuel Abbreviation	Data Source
Anthracite and Bituminous Coal	CL	U.S. Bureau of Mines, <u>Minerals Industry Surveys.</u>
Distillate	DF	U.S. Bureau of Mines, <u>Minerals Industry Surveys.</u>
Electricity	EL	Edison Electric Institute, <u>Statistical Yearbook of Electric Utility Industry.</u>
Liquid Petroleum Gas	LG	U.S. Bureau of Mines, <u>Minerals Industry Surveys.</u>
Natural Gas	NG	U.S. Bureau of Mines, <u>Minerals Industry Surveys.</u>
Residual Oil	RF	U.S. Bureau of Mines, <u>Minerals Yearbook.</u>

Table 23. Macroeconomic Variables

Variable	Variable Abbreviation	Data Source
Non-Institutional Population {16 Years and Over}	POP	U.S. Department of Commerce, Bureau of Economic Analysis, <u>Census of Population.</u>
Value Added (1)	VA i	U.S. Department of Commerce, Bureau of Economic Analysis, <u>Census of Manufactures.</u>
Gas Service Customers (2)	GSC j	American Gas Association. U.S. Bureau of Mines, <u>Minerals Yearbook.</u>
Heating Degree Days	HDD	Weather Bureau.
Cooling Degree Days	CDD	Weather Bureau.
Disposable Income	YP58N	U.S. Department of Commerce, Bureau of Economic Analysis, <u>National Income Accounts.</u>

(1)

i=1--Food Processing
=2--Paper and Pulp
=3--Chemicals
=4--Refineries
=5--Stone, Clay, and Glass
=6--Primary Metals
=7--Machinery
=8--Total Less Refinery
=9--Total

(2)

j=1--Residential
=2--Commercial
=3--Industrial

{1}

ICF, The National Coal Model, Washington, D.C., 1977.

{2}

Edison Electric Institute, 1976 Statistical Yearbook,
New York: EEI, 1976.

{3}

Federal Power Commission, Typical Electric Bills, 1977,
Washington, D.C.: U.S. Government Printing Office, 1977.

{4}

American Gas Association, Gas Facts, Arlington , Va.:
AGA, 1977.

{5}

Platt's Oilmanac, New York: McGraw-Hill.

{6}

Lundberg Survey, Inc.

{7}

Hyplan Associates, World Naptha Survey, 1976, Houston,
Texas: Hyplan Associates.

{8}

IR&T, Industrial Energy Study of the Industrial Chemicals
Group: IR&T, 1974. Table VIII-7, P. 144.

{9}

Bureau of Mines, Petroleum Statement, Washington, D.C.:
U.S. Government Printing Office. Annual 1956-76 issues.

III. STRUCTURE OF RDFOR, 1977

This chapter provides a detailed analysis of the RDFOR model. Section One presents the theoretical structure of this model and examines the functional specifications of the equations and their relationship to other economic models of demand. In addition, this Section analyzes a transportation sector model and a minor fuels sector model which differ in structure from the other sector models within RDFOR. Section Two discusses the estimation methods utilized and concentrates on an analysis of the error terms and their implications for the estimated parameters of the model. These are coupled with a discussion of the regional disaggregation of the model and the disaggregation among fuel types. Section Three reports the empirical results obtained and evaluates them in light of theoretical expectations. The last section compares the results with the findings of similar studies in order to place the entire RDFOR model in a proper perspective for energy forecasting.

1. Theoretical Structure of RDFOR

RDFOR is broken down into three submodels:

- (1) Demand relationships for the residential, commercial, and industrial sectors of the U.S. economy.
- (2) Demand for fuel in the transportation sector.
- (3) Demand equations which cover the remaining fuel consumption categories.

Each of these submodels is analyzed separately.

A. Residential, Commercial and Industrial Sector Fuel Demands (Submodel 1)

In this submodel, a system of demand relationships is developed which captures the basic elements of consumer and producer demand

theory. However, the functional relationships used are not directly related to the underlying theory, and the exact specifications are not directly deducible. In part, this is due to the high level of aggregation employed in the model, which makes it difficult to impose theoretical structures on the demand relationships. Thus, specifications should be interpreted as the reduced forms of underlying but unspecified structures.

There are two basic demand relationships. The first relates the total use of fuel to the other goods and services in the economy. The second analyzes the distribution of this total fuel demand between different types of fuels. This type of structure has implications for the extent to which different types of fuel and non-fuel goods interact as well as how changes in the rest of the economy affect various types of fuels demanded.

Aggregate Per Capita Fuel Demand. Aggregate per capita energy consumption depends on (1) a measure of the price of energy (2) the level of per capita economic activity--which represents either the per capita income of consumers or value added in manufacturing and (3) the number of heating degree days and cooling degree days--which reflect shifts over time and across regions in aggregate energy demand. These latter two variables serve as proxies for variations in temperatures.

The demand function is written as:

$$(III-1) \quad TQ = f(TP, Y, HDD, CDD)$$

where TQ is a value weighted geometric index of per capita fuel types, TP is a value weighted geometric index of individual fuel prices, Y is either disposable income per capita (for the residential and commercial sector) or value added in manufacturing (VA in the industrial sector), HDD is the heating degree days, and CDD is cooling degree days.

Since both TQ and TP are "total" indices based only on the prices and quantities of various fuels, the substitutability or complementarity of non-fuel goods and services with fuels are not directly modeled by this formulation. In particular, this specification does not directly account for the effects of changes in the prices of non-fuel goods and services upon energy demand.

Specific Per Capita Fuel Demand. The per capita quantity demanded of a specific fuel type relative to the per capita aggregate fuel demand (Q/TQ) is modeled to depend on (1) the price of the fuel in question relative to a price index for all fuels, and (2) the availability of natural gas in a region.

$$(III-2) \quad Q/TQ = g(P/TP, GSC)$$

where GSC is the availability of natural gas as measured by gas service customers.

This specification limits the price sensitivity of the specific fuel demand to the index of fuel prices. Since the value weight of fuel prices in the index is determined by the shares of the fuels in the total price index, the substitution effects are dominated by the share of a fuel in total fuel demand. The change in price of a fuel that has a low weight in the total price index will have a smaller effect on demand relative to the change in the price of a fuel that has a large weight.

The total price index (TP) and the total quantity index (TQ) are Divisia indices and are calculated by:

$$(III-3) \ln TP = \sum (\ln P(k) * W(k))$$

$$(III-4) \ln TQ = \sum (\ln Q(k) * W(k))$$

where $P(k)$ and $Q(k)$ are the price and the quantity of the k th fuel, respectively, and $W(k)$ is the weight. The summation (SUM) is over k and the weights are computed by:

$$(III-5) W(k) = (S(k,t) * S(k,t-1))^{**0.5} / \sum (S(k,t) * S(k,t-1))^{**0.5}$$

where

$$(III-6) S(k,t) = P(k,t) * Q(k,t) / \sum (P(k,t) * Q(k,t))$$

These weights vary over time, altering the relative importance of various fuels as demand conditions change. Note also that current TP and TQ depend on both current and lagged prices and quantities. Dependency of current TP on current TQ imposes some problem when simulating the model for future forecasts. This point will be discussed in detail in the next chapter.

To examine an important implication of the above scheme, we assume the weight is fixed. Let the percentage changes in Q/TQ and TQ for a one percent change in P/TP and TP be b and b' , respectively. Then a one percent change in $P(j)$ induces a percentage change in $Q(i)/TQ$. When i and j are not equal, the magnitude of this change is derived below. Assume that the specifications (III.1) and (III.2) are multiplicative and that they can be written in log form as (III.1a) and (III.2a), respectively:

$$(III.1a) \ln TQ = a' + b' \ln TP + \dots$$

$$(III.2a) \ln (q(i)/TQ) = a(i) + b(i) \ln (P(i)/TP) + \dots$$

From (III.2a):

$$\ln Q(i) = a(i) + b(i) \ln (P(i)/TP) + \ln TQ + \dots$$

Substituting for TQ and TP from (III.1a) and (III.3), respectively yields:

$$\ln Q(i) = a(i) + b(i) \ln P(i) - b(i) [\sum (\ln P(i) * W(i))] + a' + b' [\sum (\ln P(i) * W(i))] + \dots$$

which, after simplification, yields:

$$(III.2b) \ln Q(i) = (a(i) + a') + b(i) \ln P(i) + (b' - b(i)) \sum (W(i) \ln P(i)) + \dots$$

The cross price elasticity, i.e., when i is not equal to j , is given by:

$$(III-7) \frac{d \ln Q(i)}{d \ln P(j)} = (b' - b(i)) W(j)$$

where d in the right handside of (III-7) designates "fastest" derivatives.

Since all weights are positive by definition, this specification limits the interaction of fuels to being all substitutes or complements in demand. Since $(b' - b(i))$ remains constant as $P(j)$ changes, any complementary fuel inputs will be swamped by the substitution effects of other fuels and show up as substitutes in demand as well.

The relative cross price elasticities of one fuel with all other fuel types depend only on the weights of the fuels in the total price index. The larger the value weight of a fuel in this index, the larger (in absolute terms) is the cross price elasticity.

The weighting scheme has implications for the own price elasticities of demand also. Using (III.2b) again, a one percent change in $P(j)$ induces a percentage change in $(Q(j)/TQ)$ of:

$$(III-8) \quad b(j) + (b' - b(j)) W(j) \quad i = j$$

The larger the weight of the fuel in total fuel value, the more inelastic is the demand for the fuel.

The availability of natural gas is used as a proxy to incorporate into the model the regional variations in the natural gas market. Essentially, the specification of this variable in the demand equation assumes that the demand for natural gas is constant across all regions while the supply curve shifts up and down depending on the region. These fluctuations in this variable represent shifts in the price of obtaining natural gas in a region. When the supply of a fuel in a region increases, the price decreases so as to reflect substitution away from other substitute fuels {1}.

The dynamic behavior of the model is provided by the lag structure of the variables. The specific adjustment mechanism utilized is a geometric distributed lag. However, the underlying lag structure for each variable is not constrained to be the same, and in some cases variables are not lagged at all.

The model allows income and price variables to have different lag structures. To account for these differences, the income variable is modified to represent a form of permanent income. Temporary fluctuations in the income of a region will not affect the permanent demand for fuel. Therefore, when a sector experiences a temporary reduction in income, the quantity of a fuel demanded will not change as dramatically as when the region experiences a permanent reduction in income.

The permanent income (YPERM) is generated by imposing an arbitrary geometric lag structure on current and past disposable incomes, i.e.:

$$(III-9) \quad YPERM(t) = 4/7 Y(t) + 2/7 Y(t-1) + 1/7 Y(t-2)$$

The effect of lagged period prices on current period consumption is also assumed to follow a geometric lag distribution. It is through this lagged adjustment process that the dynamics of demand adjustment are captured.

Using the permanent income variable generated in equation III-9 and a geometric lag structure of the total price index, a stochastic version of equation III-1 is expressed linearly in the logs of the variables as:

$$(III-10) \quad TQ(t) = a + b \sum_i [(g^i) TP(t-i)] + \\ c \text{ PERM}(t) + d \text{ HDD}(t) + e \text{ CDD}(t) + \\ h (TQ(t-1)) + u(t)$$

where i goes from zero to infinity; t represents time period; $u(t)$ is the stochastic error term; a , b , c , d , and e are parameters of the specification, and all the other variables are as defined previously.

Applying the Koyck transformation (assuming $|g| < 1$) to Equation III-10, we have,

$$\begin{aligned} \text{(III-11)} \quad TQ(t) = & a (1-g) + g TQ(t-1) + b TP(t) + c YPERM(t) - \\ & c g YPERM(t-1) + d HDD(t) - d g HDD(t-1) + \\ & e CDD(t) - e g CDD(t-1) + (u(t) - g u(t-1)) \end{aligned}$$

There are two points which should be noted regarding the transformed equation III-11. First, this equation is overidentified in some of its parameters. Second, its error term is characterized by an autoregressive structure with g as the autoregressive parameter. The issues surrounding these two points are discussed in the next section.

A similar dynamic procedure is used for the relationship specifying the demand for the share of an individual fuel in total fuel consumption. The effects of past period prices are assumed to follow a geometric lag structure while the availability of natural gas is assumed to be effective only in the current period. Equation III-2 is specified linearly in the logs of the variables as :

$$\begin{aligned} \text{(III-12)} \quad (Q(t)/TQ(t)) = & a + b (\text{SUM}((g^*i) P(t-i)/TP(t-i))) + \\ & c GSC(t) + u(t) \end{aligned}$$

where i goes from zero to infinity; $u(t)$ is the stochastic error term; and a , b , and c are parameters of the specification. Again applying the Koyck transformation to Equation III-12, we obtain:

$$\begin{aligned} \text{(III-13)} \quad (Q(t)/TQ(t)) = & a (1-g) + b (P(t)/TP(t)) + c GSC(t) - \\ & c g (GSC(t-1)) + g (Q(t-1)/TQ(t-1)) + \\ & u(t) - g u(t-1) \end{aligned}$$

The two points mentioned earlier in relation to the transformed Equation III-11, i.e., overidentification of some parameters and autoregressive lag structure, are also applicable to the transformed equation III-13.

The relationships in Equations III-11 and III-13 provide the structure of the econometric demand model. They provide the basis for obtaining estimates of demand parameters for different fuels across regions. A specification similar to Equation III-11 is estimated for each region, while Equation III-13 is estimated for each major fuel type in each region. The exact form of these specifications, which are finally empirically estimated, are given below:

$$\begin{aligned}
 \text{(III-14)} \quad TQ(t) = & a (1-g) (1-p) + (g-p) TQ(t-1) - \\
 & g p (TQ(t-2)) + b TP(t) - b p TP(t-1) + \\
 & c YPERM(t) - c (p+g) YPERM(t-1) - \\
 & c g p YPERM(t-2) + d HDD(t) - d (g+p) HDD(t-1) - \\
 & d g p HDD(t-2) + e CDD(t) - \\
 & e (g+p) CDD(t-1) - e s p CDD(t-2) + u(t) - \\
 & (g+p) u(t-1) - s p u(t-2)
 \end{aligned}$$

$$\begin{aligned}
 \text{(III-15)} \quad (Q(t)/TQ(t)) = & a (1-g) (1-p) + (g-p) (Q(t-1)/ \\
 & TQ(t-1)) - g p (Q(t-2)/TQ(t-2)) + \\
 & b (P(t)/TP(t)) - b p (P(t-1)/ \\
 & TP(t-1)) + c GSC(t) - c (g+p) \\
 & GSC(t-1) - c g p GSC(t-2) + u(t) - \\
 & (g+p) u(t-1) - g p u(t-2).
 \end{aligned}$$

The parameters in III-14 and III-15 are not related although the same notations are utilized.

B. Transportation Sector Fuel Demands (Submodel 2)

For the most part, the demand for fuel in the transportation sector is modeled by end use. Interfuel substitution is assumed to be less significant in the transportation sector than in the commercial, residential, or manufacturing sectors.

The major components of demand for fuel in the transportation sector are auto highway gasoline use, non-auto highway gasoline and diesel fuel use, rail diesel fuel use, and commercial jet fuel. A summary of the transportation fuel relationships is presented in Table 24.

The demand for automobile gasoline is determined by modeling vehicle and fleet average miles per gallon separately. Vehicle miles is specified as a function of per capita income, I ; the cost of vehicle operation (including both fuel and time costs), C ; and the unemployment rate, U :

$$\text{(III-16)} \quad VM = VM(I, C, U).$$

Automobile demand for gasoline is determined by taking the ratio of automobile vehicle miles to average fleet efficiency. The fleet efficiency is specified as a weighted average of the efficiency of automobiles of various age, assuming new cars are driven more than older cars. Exponential scrapping of the existing fleet is also specified.

Given the desired vehicle miles, the demand for new cars depends on the capital stock of automobiles. The efficiency of new automobiles is determined by the price of gasoline in the current year. This assumes that future prices of gasoline are expected not to affect current demand.

For trucks and buses, total fuel is estimated as a function of vehicle miles and fleet efficiency without a vintaging effect. Combined automobile, truck, and bus fuel is split between gasoline and diesel fuel on the basis of the relative prices of the fuels, an industrial production index, total vehicle miles, and a measure of the size of the truck stock. This relationship is not dynamic in character although the automobile and truck stocks do imply a short adjustment process. Interfuel substitution is allowed in the truck and bus demand specifications.

Total rail ton miles is specified as a function of diesel fuel price and capital expenditures in the railroad industry. The demand for rail diesel fuel is then specified as a function of rail ton miles.

Commercial jet fuel is a function of air passenger miles adjusted by an airplane load factor in order to account for excess capacity of air flights. Air passenger miles are a function of

Table 24. Summary of Transportation Fuel Relationships

Dependent Variables	Independent Variables
1. Cost of auto driving	Price of gasoline; Time-cost of wages foregone
2. Auto vehicle miles (VM) per capita demanded	Cost; Per capita income; Unemployment rate
3. New car sales	VM; Unemployment rate; Per capita income; VM capacity of last period's existing stock
5. Average mpg of entire stock of autos	Weighted geometric mean of mpg's from current and past vintages
6. Auto gasoline demanded	Auto VM divided by average mpg of auto stock
7. Truck VM	Weighted average of prices of gasoline and diesel fuel; GNP; Industrial Production Index
8. Truck mpg	Interest rate; Unemployment rate; Industrial production index.
9. Truck fuel	Truck VM divided by truck mpg
10. Bus VM	Weighted average of prices of gasoline and diesel fuel; Per capita income
11. Bus mpg	Unemployment rate; Average speed of buses
12. Bus fuel	Bus VM divided by bus mpg
13. Ratio of truck & bus gasoline to truck & bus diesel fuel	Ratio of gasoline to diesel fuel price; Industrial production index; Ratio of single-unit to combination trucks.
14. Rail ton miles	Diesel fuel price (not including highway taxes); Capital expenditures in the railroad industry.

15. Rail diesel fuel	Rail ton miles; Index of employee compensation (nonfarm).
16. Air passenger miles	Cost per passenger mile of aircraft operation (part of which is the price of jet fuel); Per capita income.
17. Commercial jet fuel	Air passenger miles adjusted by CAB load factor.
18. Non-highway gasoline	Gross national product.
19. Military jet fuel	Constant at 1975 level
20. Liquid gases	Liquid gases lagged one period; FRB index for manufacturing.
21. Residual oil	Residual oil lagged one period; Contemporaneous and lagged rail diesel fuel; Diesel-residual fuel price ratio.
22. Coal	Time

operating costs, including the price of jet fuel, per capita income, and the price of military type jet fuel.

C. Minor Fuel Categories (Submodel 3)

Separate models for fuel categories not considered thus far make up the third submodel of RDFOR. These include the demand for natural gas, liquid gas and coal in the raw materials sector; commercial demand for asphalt, and liquid gas; industrial demand for petroleum gases and metallurgical coal; and the household/commercial demand for coal.

Except for the commercial demand for liquid gas, price variables are not included in these specifications. Instead, the consumption of these fuels is a function of industrial value added, time trends, lagged consumption variables, and in the case of asphalt, gasoline consumption. The exact specifications, which are estimated in the logs of the variables, are given in Table 25.

Table 25. Summary of Minor Fuel Relationships

Fuel Category	Explanatory Variables
Raw Materials Natural Gas	VA28*
Commercial Liquid Gases	Industrial Liquid Gas Price, Lagged Quantity
Feedstocks Liquid Gases	VA28, Lagged VA28, Lagged Quantity
Raw Materials Liquid Gases	Time Trends, Lagged Quantity
Raw Materials Coal	Time Trends, Lagged Quantity
Industrial Petroleum Gases	VA28*, Lagged VA28, Lagged Quantity
Commercial Asphalt	Gasoline Consumption, Lagged Output
Household/Commercial Coal	Time, Lagged Quantity
Industrial Metallurgical Coal	VA33, Lagged VA33, Lagged Quantity

*VA28=Value added in SIC 28 (chemicals).

*VA33=Value added in SIC 33 (primary metals).

2. Estimation Methods

This section discusses the statistical techniques used to empirically estimate the three submodels presented in Section 1. Implications of the structural specifications and appropriateness of the techniques used are also examined.

The first submodel--containing the residential, commercial and industrial sectors--is estimated using a pooled cross-section of time series data. Each fuel equation is estimated making use of the non-diagonal covariance matrix of the regional error terms. Information in the data concerning sectoral variation is then used to obtain parameter estimates. This type of analysis allows

correlations between sectors that are not explicitly included in the structural specifications to be incorporated into the parameter estimates through the covariance matrix of the error terms.

The second submodel--fuel demand in the transportation sector--uses a single equation time series technique. No joint equation estimation method is used here, in contrast to the technique used in the first submodel.

The third submodel--which estimates a collection of equations for the remaining fuel demands--uses an estimation technique similar to the one used in the second submodel group.

The specific cases are considered below.

A. Residential, Commercial and Industrial Submodel

The major fuel demand specifications in the residential, commercial and industrial sectors are estimated using a pooled cross-section of time series. Different states and DOE regions constitute the source of cross-section variation in the data.

The theoretical design of this submodel is three dimensional in that there is variation in demand (1) between different types of fuels, (2) over time, and (3) across regions. However, to pool all three of these elements into one large system to estimate all the parameters is computationally infeasible. The alternative chosen is to pool data across consuming regions and over time and estimate an interrelated system of aggregate as well as individual fuel equations.

For each fuel, variations in data across regions as well as over time are used to estimate the relationship between the variables. To illustrate the nature of the cross-section of time series model, we ignore the lagged variables in the following discussion {2}. The general specification of such equations is:

$$(III-17) \quad TQ(i,t) = a(i) + b(i) TP(i,t) + c(i) Y(i,t) + u(i,t)$$

where the subscripts i and t refer to region and time, respectively. Note that each parameter is subscripted to represent shifts in parameters between regions. Essentially, this structure allows slope coefficients as well as intercept coefficients to differ among regions. With error terms independent over time, but with a non-diagonal contemporaneous covariance matrix across regions, this system represents a simple Zellner seemingly unrelated regression {3}. This also requires that there be no correlation between error terms over time, either within or between regions. However, correlations between

the errors of different regions in a single time period is allowed.

Each region has coefficients that are particular to it, while information gained by estimating regions jointly comes from the fact that variables not explicitly included in the econometric specifications affect demand in each region so as to correlate the errors of the demand equations. These correlations are captured in the covariance matrix of the error terms of all regions. For example, national emergencies such as wars may affect fuel demand even though variables have been left out that would take explicit account of such factors. Making use of the contemporaneous covariance of the error terms allows the estimation procedure to make use of information in one region to gain information about another.

A further restriction is imposed on the general specification in (III-17). Specifically, the model assumes that the slope coefficients are no longer subscripted, i.e.:

$$(III-18) \quad TQ(i,t) = a(i) + b TP(i,t) + c Y(i,t) + u(i,t)$$

This specification means that response of quantity demanded to changes in variables does not differ across regions. However, the aggregate level of demand can differ by region, as illustrated through the differences in the shift terms among regions.

Assuming that the error structure in (III-18) is such that error terms are independent over time while they have a non-diagonal contemporaneous covariance matrix, the system (III-18) reduces to a constrained Zellner seemingly unrelated regression framework. The constraint is that the slope coefficient of each regional demand equation is the same. This specification may be empirically examined through imposition of a set of linear homogeneous constraints on the set of parameter estimates in (III-17). Specifically, (III-18) implies that the parameters in the general specification (III-17) are constrained by:

$$(III-19) \quad \begin{array}{ll} b(i) = b & \text{for all } i \\ c(i) = c. & \end{array}$$

An F-test of the constraint will indicate whether or not the data is consistent with the constraints in (III-19).

The structure, as it is represented in (III-18), is efficiently estimated using a Zellner minimum distance algorithm, which is a member of the class of iterative generalized least squares techniques. In this specific case, the structure of (III-18) is estimated using a full information maximum likelihood procedure which reduces to the iterative Zellner technique, but takes advantage of the computational efficiency of the package containing the full information maximum likelihood technique.

An important assumption under the Zellner seemingly unrelated regression technique is that error terms are not correlated over time. Preliminary estimates of (III-18), particularly in terms of the Durbin-Watson statistics, indicate that this assumption is not fully satisfied. Although the Durbin-Watson statistic is biased when there are lagged dependent variables on the right hand side of an estimating equation, the large Durbin-Watson statistics for the untransformed equations in (III-18) suggest that the error terms are serially correlated.

To correct for this, a first order auto-regressive process on the error terms is imposed on the system. Although higher order auto-regressive processes may be involved, a direct method of analyzing time series processes of the error terms is through the imposition of this first order auto-regressive scheme. A plot of residuals from these estimated equations could be used to check the appropriateness of this transformation. Using the Koyck transformation, the estimating equations are adjusted to incorporate this auto-regressive error structure, leaving the transformed system in a form more appropriate for estimation.

A few points with respect to the adequacy of the above transformation are in order. Serial correlation in the error structure of estimating equations could be due to a number of factors including (a) errors in measurement, (b) omission of variables, and (c) misspecification of the model. The underlying assumption in this transformation stems from the first factor and, to the extent that b and c are present, the transformation is inadequate. The auto-regressive adjustment is made in order to correct for errors in measurement of variables during the sample period. This is useful because it allows simulations of future period fuel demands to ignore the auto-regressive transformation (but not those in the historical period).

Using this serial correlation adjustment, specifications in (III-11) and (III-13) of the preceding section are transformed to obtain the final forms of equations for estimation. These transformed structures are already presented in (III-14) and (III-15) in Section 1.

The assumption made in the estimation procedure is that the error terms in (III-14) and (III-15) are not serially correlated. Therefore, it is assumed that $u(t) - (g+p) u(t-1) - g p u(t-2)$ of the two systems are not correlated over time.

After (III-14) and (III-15) are econometrically estimated, values of "individual" parameters can be determined. For example, in (III-14) the coefficients on $TP(t)$ and $TP(t-1)$ are sufficient to identify the parameter p . The estimate of g may then be obtained from the coefficients on $TP(t-1)$, $TQ(t-1)$, $YPERM(t-1)$, $YPERM(t-2)$, $HDD(t-1)$, $HDD(t-2)$, $CDD(t-1)$, and $CDD(t-2)$. In (III-15) the identification of p from the coefficients on the price variables permits multiple estimates of g . This means that the model derived from (III-1) and (III-2) and culminating in

specifications (III-14) and (III-15) in the previous section imposes restrictions on the coefficients (namely that all estimates of g are the same). This may be directly tested making use of the nonlinear restrictions on the coefficients in (III-14) and (III-15). The likelihood ratio test of the restrictions will indicate whether or not the data support these parameter restrictions.

Note that in (III-14) and (III-15) both the intercept terms and the auto-regressive parameters are regionally variable. Subscripts denoting these geographical variations are omitted for simplicity in presentations (see (III-18)). The assumption that historical data contains measurement errors which are not geographically neutral indicates that the auto-regressive parameters might be different across geographical regions.

B. Transportation Submodel

Single equation time series estimation techniques are used to obtain parameter estimates for the transportation sector demand model. The presence of simultaneity in the structure of this sector is regarded insignificant. To the extent that this may not hold, the assumptions underlying the estimation technique used may not be satisfied.

In the rail diesel fuel and auto vehicle miles equations endogenous variables are included as explanatory variables. Although there are other equations consisting only of exogenous variables that determine these variables, thereby suggesting a block diagonal system of simultaneous equations, the use of ordinary least squares might still be questionable. Specifically, it is necessary that the error structure of these equations be diagonal. Otherwise, inconsistent parameter estimates will be obtained. The appropriateness of the non-simultaneity assumption may be examined by analyzing the off-diagonal elements of the error covariance matrix.

C. Minor Fuels Submodel

The minor fuel demand models are also estimated using single equation time series econometric techniques. Serial correlation in the error terms are adjusted by assuming a first order auto-regressive process and using the Koyck transformation to modify the specifications into an estimable form. All equations are estimated in logs of variables. The final specifications used for estimating are presented in Table 25, Section 1.

Appropriateness of the auto-regressive transformation in this instance is again subject to the same qualifications expressed earlier in conjunction with the first submodel. It is assumed that the system presented in Table 25, Section 1, is correctly specified.

3. RDFOR Empirical Results and Their Evaluation

This section reports and evaluates the results of estimation of the three RDFOR demand submodels. The analysis concentrates on the implications of the parameter estimates for energy demand.

A. Residential Demand Results

The coefficient estimates for residential demand for major fuels are presented in Table 26. The short-run price elasticity of demand for all fuels is relatively low, ranging from $-.064$ to $-.184$. The long-run price elasticities are about double the short-run estimates but still remain inelastic. The short-run income term is less than unity for all the DOE regions--ranging from $.863$ to $.568$. However, when the adjustment process is taken into account, these figures also double, resulting in long-run income elasticities greater than unity.

The short-run price elasticities for electricity, natural gas, distillate oil, and liquid gas are all larger than the total fuel price elasticity. This is consistent with prior expectations that there are greater substitution possibilities within more disaggregated product classifications than between aggregate product groupings.

In general, coefficients on lag terms are also larger, which increases the size of the long-run price elasticities of the various fuel categories relative to the total fuel long-run elasticity. Table 27 presents the long-run price elasticities in the total and component fuel categories.

Table 26. Residential Major Fuels Estimations

Coefficient	DOE Regions				
	1	2	3	4	5
TOTAL					
Price	-.184	-.184	-.092	-.139	-.064
Lag Term	.400	.400	.535	.638	.519
Income	.769	.769	.652	.863	.568
Heat. Deg. Days	.098	.098	.302	.207	.132
Cool. Deg. Days	.060	.060	.020	.188	.0
DISTILLATE OIL					
Price	-.704	-.704	-.246	-.539	-.185
Lag Term	.638	.638	.806	.662	.826
Income	.0	.0	.0	.0	.0
Gas Ser. Cust.	.0	.0	.0	-.318	-.339
ELECTRICITY					
Price	-.290	-.290	-.318	-.259	.180
Lag Term	.852	.852	.845	.731	.914
Income	.0	.0	.0	.101	.0
Gas Ser. Cust.	-.016	-.016	-.158	.0	.0
LIQUID GAS					
Price	-.432	-.432	-.184	-.337	-.460
Lag Term	.541	.541	.3229	.579	.310
Gas Ser. Cust.	-.047	-.047	-.416	.0	.0
NATURAL GAS					
Price	-.221	-.221	-.221	-.253	-.234
Lag Term	.774	.774	.774	.855	.470
Income	.0	.0	.0	.0	-.024
Gas Ser. Cust.	.0	.0	.0	.0	.163

Table 26. Residential Major Fuels Estimations (Continued)

Coefficient	DOE Regions				
	6	7	8	9	10
TOTAL					
Price	-.064	-.064	-.064	.064	-.064
Lag Term	.519	.519	.519	.519	.519
Income	.568	.568	.568	.568	.568
Heat. Deg. Days	.132	.132	.132	.132	.132
Cool. Deg. Days	.0	.0	.0	.0	.0
DISTILLATE OIL					
Price	-.765	-.765	-.460	-.700	-.700
Lag Term	.610	.610	.696	.271	.271
Income	.555	.0	.0	.0	.0
Gas Serv. Cust.	-.230	-.230	-.434	-.118	-.118
ELECTRICITY					
Price	-.382	-.382	-.519	-.538	-.538
Lag Term	.677	.677	.300	.250	.250
Income	.0	.0	.0	-.003	-.003
Gas Ser. Cust.	.0	.0	.0	.0	.0
LIQUID GAS					
Price	-.221	-.221	-.460	-.454	-.454
Lag Term	.667	.667	.310	.839	.839
Gas Ser. Cust.	-.039	-.039	.0	-.091	-.091
NATURAL GAS					
Price	-.407	-.407	-.633	-.421	-.421
Lag Term	.417	.417	.100	.628	.628
Income	.0	.0	.317	.0	.0
Gas Ser. Cust.	.320	.320	.336	.115	.115

The coefficients on gas service customers (GSC) are negative (or constrained to zero in some cases) for electricity, distillate oil, and liquid gas demand. This is in accordance with our prior expectations. The inclusion of this variable in the demand for natural gas equation, however, is not readily justifiable, since it is supposed to represent a supply shifting variable. In addition, since this variable is also determined by price of natural gas, its role as an exogenous variable is unclear. However, GSC has a positive coefficient for natural gas, confirming that the number of gas service customers is positively associated with consumption of natural gas. In sum, the significance as well as the interpretation of this variable turns out to be more complex. It is highly possible that GSC picks up some of the sensitivity of demand not captured by the price variable.

B. Commercial Demand Results

The coefficient estimates for the commercial demand for major fuels are presented in Table 28. The short-run price elasticities of demand for fuel totals, $-.162$, is less than unity although larger than that for residential demand. The lag term coefficient is larger than that in the residential sector, thereby increasing the long-run price elasticities substantially. The long-run total fuel price elasticity jumps to $-.602$.

Table 27. Long-Run Price Elasticities for Residential Demand for Major Fuels

Coefficient	DOE Regions				
	1	2	3	4	5
Total	-.307	-.307	0.198	-.384	-.133
Distillate Oil	-1.945	-1.945	-1.268	-1.595	-1.063
Electricity	-1.960	-1.960	-2.052	-.963	-2.093
Liquid Gas	-.941	-.941	-.274	-.801	-.667
Natural Gas	-.978	-.978	-.978	-1.745	-.442

Table 27. Long-Run Price Elasticities for Residential Demand for Major Fuels (Continued)

Coefficient	DOE Regions				
	6	7	8	9	10
Total	-.133	-.133	-.133	-.133	-.133
Distillate Oil	-1.962	-1.962	-1.513	-.960	-.960
Electricity	-1.183	-1.183	-.741	-.717	-.717
Liquid Gas	-.664	-.664	-.667	-2.82	-2.82
Natural Gas	-.698	-.698	-.703	-1.132	-1.132

Table 28. Commercial Major Fuel Estimations

Coefficient	DOE Regions					
	1	2	3	4	5	6
Total						
Price	-.162	-.162	-.162	-.162	-.162	-.162
Lag Term	.731	.731	.731	.731	.731	.731
Income	.734	.734	.734	.734	.734	.734
Heat. D. D.	.243	.243	.243	.243	.243	.243
Cool. D. D.	.209	.209	.209	.209	.209	.209
Electricity						
Price	-.323	-.323	-.297	-.662	-.373	-.337
Lag Term	.656	.656	.704	.500	.757	.639
Income	.0	.0	.0	.0	.0	.0
Gas Sv. Cs.	-.031	-.031	-.004	-.063	.0	.0
Distillate Oil						
Price	-.190	-.190	-.360	-.360	-.360	-.360
Lag Term	.787	.787	.478	.478	.478	.478
Gas Sv. Cs.	-.038	-.038	-.339	-.339	-.339	-.339
Natural Gas						
Price	-.317	-.317	-.317	-.317	-.317	-.317
Lag Term	.700	.700	.700	.700	.700	.700
Gas Sv. Cus.	.380	.380	.380	.380	.380	.380
Residual Oil						
Price	-.220	-.220	-.220	-.220	-.220	-.220
Lag Term	.777	.777	.777	.777	.777	.777

Figure 13.

Table 28. Commercial Major Fuel Estimations (Continued)

Coefficient	DOE Regions			
	7	8	9	10
Total				
Price	-.162	-.162	-.162	.162
Lag Term	.731	.731	.731	.731
Income	.734	.734	.734	.734
Heating Degree Days	.243	.243	.243	.243
Cooling Degree Days	.209	.209	.209	.209
Electricity				
Price	-.337	-.405	-.609	-.609
Lag Term	.639	.639	.593	.476
Income	.0	.0	.0	.073
Gas Service Customers	.0	-.121	.0	.0
Distillate Oil				
Price	-.360	-.360	-.360	-.360
Lag Term	.478	.478	.478	.478
Gas	-.339	-.339	-.339	-.339
Natural Gas				
Price	-.317	-.317	-.317	-.317
Lag Term	.700	.700	.700	.700
Gas Service Customers	.380	.380	.380	.380
Residual Oil				
Price	-.220	-.220	-.220	-.220
Lag Term	.777	.777	.777	.777

The income elasticity is .734 in the short-run, not much larger than estimates for the residential sector. However, due to the large coefficient on the lag term, long-run income elasticities are greater than two, substantially larger than those for the residential sector.

The price elasticities of demand for the four component fuels are all larger than those for total fuels. As in the residential sector, this illustrates the increased price sensitivity within general consumption categories relative to between-category price sensitivity. The lag terms for these separate fuels is about the same magnitude as that for total fuel, except for distillate oil in DOE regions 3-10. The largest difference between residential and commercial sector price elasticities is in distillate oil. The commercial sector elasticities are generally twice as large as those in the residential sector. The long-run price elasticities for the commercial fuel demands are presented in Table 29.

The coefficient associated with gas service customers is negative (or zero) in the electricity and distillate oil categories while it is positive in the natural gas equation. The same problems exist with the interpretation of this variable in the commercial natural gas equation as in residential demand for natural gas.

C. Industrial Demand Results

The coefficient estimates for industrial demand for major fuels are presented in Table 30. The short-run price elasticities for total fuel demand, $-.049$, are lower than those for either the commercial or residential sectors.

Table 29. Long-Run Price Elasticities for Commercial Demand for Major Fuels

Coefficient	DOE Regions				
	1	2	3	4	5
Total	-.602	-.602	-.602	-.602	-.602
Distillate Oil	-.892	-.892	-.690	-.690	-.690
Electricity	-.939	-.939	-1.003	-1.324	-1.535
Natural Gas	-1.057	-1.057	-1.057	-1.057	-1.057
Residual Oil	-.987	-.987	-.987	-.987	-.987

Table 29. Long-Run Price Elasticities for Commercial Demand for Major Fuels (Continued)

Coefficient	DOE Regions				
	6	7	8	9	10
Total	-.602	-.602	-.602	-.602	-.602
Distillate	-.690	-.690	-.690	-.690	-.690
Electricity	-.934	-.934	-.995	-1.162	-1.162
Natural Gas	-1.057	-1.057	-1.057	-1.057	-1.057
Residual Oil	-.987	-.987	-.987	-.987	-.987

Table 30. Industrial Major Fuel Estimations

Coefficient	DOE Regions					
	1	2	3	4	5	6
Total						
Price	-.049	-.049	-.049	-.049	-.049	-.049
Lag Term	.381	.381	.381	.381	.381	.381
Heating Deg. Days	.174	.174	.174	.174	.174	.174
Cooling Deg. Days	.252	.252	.252	.252	.252	.252
Coal						
Price	-.281	-.281	-.281	-.281	-.281	-.281
Lag Term	.575	.575	.575	.575	.575	.575
Distillate Oil						
Price	-.215	-.215	-.215	-.215	-.215	-.215
Lag Term	.599	.599	.599	.599	.599	.599
Electricity						
Price	-.170	-.170	-.170	-.170	-.170	-.170
Lag Term	.772	.772	.772	.772	.772	.772
Liquid Gas						
Price	-.165	-.165	-.165	-.165	-.165	-.165
Lag Term	.603	.603	.603	.603	.603	.603
Natural Gas						
Price	-.211	-.211	-.211	-.211	-.211	-.211
Lag Term	.528	.528	.528	.528	.528	.528
Residual Oil						
Price	-.133	-.133	-.133	-.133	-.133	-.133
Lag Term	.817	.817	.817	.817	.817	.817

Table 30. Industrial Major Fuel Estimations (Continued)

Coefficient	DOE Regions					
	7	8	9	10	Mean	Avg. L-R Elast.
Total						
Price	-.049	-.049	-.049	-.049	-.049	-.079
Lag Term	.381	.381	.381	.381		
Heat. D.D.	.174	.174	.174	.174		
Cool. D.D.	.252	.252	.252	.252		
Coal						
Price	-.281	-.281	-.281	-.281	-.281	-.489
Lag Term	.575	.575	.575	.575		
Distillate Oil						
Price	-.215	-.215	-.215	-.215	-.215	-.536
Lag Term	.599	.599	.599	.599		
Electricity						
Price	-.170	-.170	-.170	-.170	-.170	-.746
Lag Term	.772	.772	.772	.772		
Liquid Gas						
Price	-.165	-.165	-.165	-.165	-.165	-.416
Lag Term	.603	.603	.603	.603		
Natural Gas						
Price	-.211	-.211	-.211	-.211	-.211	-.447
Lag Term	.528	.528	.528	.528		
Residual Oil						
Price	-.133	-.133	-.133	-.133	-.133	-.727
Lag Term	.817	.817	.817	.817		

In addition, the coefficient on the lag term, .381, is lower than the other sectors so the long-run price elasticities remain very low, around -.79.

The short-run price elasticities for electricity, natural gas, distillate oil, residual oil, liquid gas, and coal are all larger than that for the total, although still low relative to the other sector fuel demands. The lag term coefficients range from .528 for natural gas to .817 in residual oil so that long-run price elasticities are all less than unity, ranging from -.416 in

liquid gas to $-.746$ in electricity. Long-run price elasticities for the industrial fuel demands are summarized in the last column of Table 30.

D. Transportation Demand Results

The price and income elasticities of demand for fuel in the transportation sector are summarized in Table 31. The price elasticities are all less than unity implying that the demand for fuel is not very sensitive to changes in the prices of fuels. The income elasticities for auto, airline, and truck fuel demands are all larger than unity, implying that as future incomes go up there will be a relatively larger demand for fuel in these transportation sectors than in the bus and rail diesel fuel sectors. These two sectors have low income elasticities of $.285$ and $.144$, respectively.

Table 31. Transportation Model Elasticities (Long-Run)

	Price Elasticities	Income Elasticities
Airline Passenger Miles	$-.245$	1.457
Auto Vehicle Miles	$-.480$	1.190
Bus Fuel Demand	$-.474$	$.285$
Rail Diesel Fuel Demand	$-.368$	$.144$
Truck Fuel Demand	$-.545$	1.740

E. Minor Fuel Demand Results

Some of the parameter estimates for the minor fuel demand specifications are presented in Table 32. Coefficients on lag terms are all less than unity--the lowest being those for raw materials demand for liquid gases and feedstocks demand for liquid gases. This implies that the ability to adjust in these sectors is large relative to the others.

The short-run and the long-run price elasticities of demand by the commercial sector for liquid gases are inelastic and range from $-.047$ to $-.084$ and $-.134$ to $-.187$, respectively.

Table 32. Parameter Estimates for Minor Fuel Demand Functions

	Value Added*	Lagged Term*	Price/ Gas Cons.
Com. Asphalt	--	--	.648 to 1.622
Com. Liq. Gases	--	.549 to .655	-.047 to -.084
Feedstocks Liq. Gas	.341	.241	--
Ind. Pet. Gases	1.323	.631	--
Metal. Coal	.329 to .366	--	--
Raw Mat. Coal	.034	.735	--
Raw Mat. Liq. Gases	1.515	.371	--

*Ranges of Coefficients are over 10 DOE Regions

F. New Equation Estimates

This subsection describes revised equation structure and estimates for jet fuel, naptha and liquid gas. These new estimates were prepared for the 1978 Director's Report to Congress (see subsections 2.A and 2.B of the previous chapter).

Jet Fuel Equation. The former version of the jet fuel equation in the RDFOR model was based on a 1975 analysis by Mark Rodekoher and Lew Rubin. In that version of the model, commercial jet fuel consumption was estimated as a function of per capita air passenger miles adjusted by an airplane load factor to account for excess capacity of the planes. Per capita air passenger miles were estimated as a function of operating costs (a part of which is the price of jet fuel) and per capita income. Military naptha type jet fuel was modeled as an exogenous variable.

Forecasts with these equations resulted in growth rates for jet fuel substantially above current trends. To improve the forecasting results, the data were updated past 1972 and the model was reestimated.

No attempt was made to modify the basic structural form of the model, i.e., per capita air passenger miles was still made a function of average total passengers revenues per revenue passenger mile and real per capita personal income; and commercial jet fuel was made a function of per capita passenger miles.

Since it was not possible to simply update the old file containing the air transportation data, new data covering the 1950-1976 period were collected. The data on jet fuel

consumption used in the new estimations came from the Civil Aeronautics Board's (CAB) Handbook of Airline Statistics{4} and monthly updates. The data represent consumption of jet fuel, all services, for total certified route air carriers. This series approximates "shipments for commercial use of kerosene type jet fuel to airlines." While these data are roughly 5-10 percent higher than the data used in the original estimations, the data nevertheless are internally consistent. In addition, the data are lower than the comparable jet fuel series used in the short-term model.

The equations were estimated in double logarithmic form using two-stage least squares with a Cochrane-Orcutt auto-regressive technique{5}. The estimation results are reported in Tables 33-35 and indicate substantially lower rates of growth in jet fuel consumption. These rates range from 1.07 to 4.39 percent/year, depending on the specific form and the sample period over which the equations were estimated.

The first two equations in Table 33 were selected for inclusion. The results of the per capita air passenger miles were an elasticity on average total passenger revenues per passenger mile of -1.3 and an income elasticity of .54 with an R-square of .98 and a DW of 1.53. The coefficient of the Jet Fuel equation was .93 for air passenger miles with an R-square of .97 and a DW of 1.78.

Table 33. Jet Fuel Equation Estimates

Years	Jet Fuel = Constant + TDMLS/Pop		
Estimated			
1956-1976	9.007 (4.47) *	.932 (1.18)	$R^2 = .97$ DW = 1.78
1957-1976	11.561 (4.19)	-.945 (-.75)	$R^2 = .96$ DW = 2.19
1958-1976	10.173 (4.49)	-.373 (-.84)	$R^2 = .95$ DW = 1.88
1959-1976	6.373 (30.35)	1.26 (15.30)	$R^2 = .99$ DW = 2.01
1960-1976	6.054 (59.96)	1.407 (28.18)	$R^2 = .99$ DW = 1.58
1961-1976	6.113 (52.62)	1.380 (24.40)	$R^2 = .98$ DW = 1.58
1962-1976	6.256 (40.48)	1.316 (17.96)	$R^2 = .98$ DW = 1.62
1963-1976	7.013 (18.85)	.963 (5.75)	$R^2 = .99$ DW = 1.07
1964-1976	6.686 (21.02)	1.053 (7.215)	$R^2 = .99$ DW = 1.38

(All equations were estimated in double logarithmic form)

*T-Statistics

Jet Fuel = Commercial Jet Fuel

TDMLS = Air passenger miles

Pop = Population

Table 33. Jet Fuel Equation Estimates (Continued)

Years Estimated	TDMLS /Pop=Constant + ARPMAR + YD72/Pop			Growth Rate For Jet Fuel Consumption	
1956-1976	3.583 (2.79) *	-1.30 (-2.92)	.540 (1.07)	$R^2 = .98$ DW = 1.53	1.07
1957-1976	3.61 (2.65)	-1.31 (-2.84)	.530 (1.21)	$R^2 = .97$ DW = 1.52	
1958-1976	3.21 (1.92)	-1.19 (-2.85)	.85 (1.03)	$R^2 = .97$ DW = 1.41	
1959-1976	3.33 (1.89)	-1.21 (-2.21)	.616 (.85)	$R^2 = .97$ DW = 1.36	2.13
1960-1976	3.43 (1.93)	-1.32 (-2.57)	.665 (.89)	$R^2 = .92$ DW = 1.44	2.40
1961-1976	3.53 (1.91)	-1.31 (-2.23)	.572 (.72)	$R^2 = .99$ DW = 1.42	2.11
1962-1976	3.621 (1.93)	-1.179 (-1.90)	.376 (.45)	$R^2 = .96$ DW = 1.35	1.52
1963-1976	3.547 (1.77)	-1.104 (-1.43)	.345 (.40)	$R^2 = .95$ DW = 1.28	
1964-1976	4.736 (2.16)	-1.209 (1.68)	-.319 (.33)	$R^2 = .94$ DW = 1.57	

(All equations were estimated in double logarithmic form)

*T-Statistics

Jet Fuel = Commercial Jet Fuel

TDMLS = Air passenger miles

ARPMAR = Average total passenger revenue per revenue passenger
mile

YD72 = Real personal income (1972 dollars)

Pop = Population

Table 34. Jet Fuel Equations

Years

Estimated Jet Fuel = Constant + TDMLS

1956-1976	1.612 (.35) *	.997 (1.57)	$R^2 = .97$ DW = 1.76
1957-1976	14.66 (1.80)	-.690 (-.65)	$R^2 = .96$ DW = 2.17
1958-1976	10.729 (1.60)	-1.84 (-.20)	$R^2 = .95$ DW = 1.87
1959-1976	.765 (1.56)	1.113 (16.58)	$R^2 = .99$ DW = 1.99
1960-1976	-.110 (.380)	1.229 (31.45)	$R^2 = .99$ DW = 1.80
1961-1976	.184 (.541)	1.190 (25.13)	$R^2 = .99$ DW = 1.39
1962-1976	.559 (1.21)	1.148 (18.26)	$R^2 = .99$ DW = 1.46
1963-1976	1.833 (1.86)	.975 (7.97)	$R^2 = .99$ DW = .985
1964-1976	1.215 (1.44)	1.055 (9.62)	$R^2 = .99$ DW = 1.22

(All equations were estimated in double logarithmic form)

*T-Statistics

Jet Fuel = Commercial Jet Fuel

TDMLS = Air passenger miles

Table 34. Jet Fuel Equation Estimates (Continued)

Years Estimated	TDMLS=Constant + ARPMAR + YD72				Growth Rate For Jet Fuel Consumption
1956-1976	5.975 (1.82)*	-1.340 (-3.04)	.559 (1.57)	$R^2 = .98$ DW = 1.60	2.00
1957-1976	6.072 (1.78)	-1.367 (-2.97)	.551 (1.30)	$R^2 = .98$ DW = 1.58	
1958-1976	5.341 (1.20)	-1.282 (-2.35)	.639 (1.16)	$R^2 = .98$ DW = 1.57	
1959-1976	5.939 (1.25)	-1.325 (-2.33)	.561 (.694)	$R^2 = .98$ DW = 1.95	2.47
1960-1976	5.668 (1.13)	-1.394 (-2.45)	.616 (.96)	$R^2 = .98$ DW = 1.47	2.91
1961-1976	6.250 (1.18)	-1.374 (-2.32)	.526 (.77)	$R^2 = .97$ DW = 1.49	2.56
1962-1976	7.174 (1.34)	-1.243 (-1.99)	.360 (.51)	$R^2 = .97$ DW = 1.42	1.85
1963-1976	7.231 (1.30)	-1.152 (-1.50)	.331 (.45)	$R^2 = .96$ DW = 1.34	
1964-1976	11.262 (1.86)	-1.324 (1.70)	-.215 (.28)	$R^2 = .95$ DW = 1.66	

(All equations were estimated in double logarithmic form)

*T-Statistics

Jet Fuel = Commercial Jet Fuel

TDMLS = Air passenger miles

ARPMAR = Average total passenger revenue per revenue passenger mile

YD72 = Real personal income (1972 dollars)

Table 35. Jet Fuel Equation Estimates

Years	Jet Fuel = Constant + PRM/Pop		
Estimated			
1956-1976	3.316 (1.42) *	.927 (2.36)	$R^2 = .97$ DW = 1.72
1957-1976	9.676 (2.48)	-.046 (-.07)	$R^2 = .97$ DW = 2.03
1958-1976	8.434 (2.43)	.137 (.24)	$R^2 = .95$ DW = 1.82
1959-1976	4.216 (9.71)	.783 (10.80)	$R^2 = .99$ DW = 1.09
1960-1976	3.795 (9.34)	.830 (12.59)	$R^2 = .99$ DW = .70
1961-1976	4.988 (7.80)	.663 (6.36)	$R^2 = .99$ DW = .90
1962-1976	5.926 (5.09)	.519 (2.81)	$R^2 = .98$ DW = 1.06
1963-1976	7.565 (2.28)	.277 (.54)	$R^2 = .97$ DW = .83
1964-1976	6.643 (2.72)	.411 (1.08)	$R^2 = .97$ DW = .96

(All equations were estimated in double logarithmic form)

*T-Statistics

Jet Fuel = Commercial Jet Fuel

PRM = Passenger revenue miles

Pop = Population

Table 35. Jet Fuel Equation Estimates (Continued)

Years Estimated	PRM/Pop=Constant + ARPMAR + YD72 /Pop			Growth Rate For Jet Fuel Consumption	
1956-1976	6.002 (4.81)*	-.936 (-2.44)	1.446 (2.67)	$R^2 = .99$ DW = 2.58	4.39
1957-197	5.504 (4.49)	-1.008 (-2.45)	1.783 (3.60)	$R^2 = .91$ DW = 2.69	
1958-1976	5.626 (3.77)	-1.203 (-2.49)	2.035 (3.60)	$R^2 = .99$ DW = 2.07	
1959-1976	7.017 (4.95)	-1.788 (-3.69)	1.64 (3.44)	$R^2 = .99$ DW = 2.64	3.02
1960-1976	7.636 (5.5)	-2.01 (-4.24)	1.46 (3.12)	$R^2 = .99$ DW = 2.40	3.01
1961-1976	9.006 (7.48)	-2.48 (-6.00)	1.00 (2.45)	$R^2 = .99$ DW = 2.17	2.09
1962-1976	9.870 (2.11)	-2.751 (-8.50)	.687 (2.11)	$R^2 = .99$ DW = 1.96	1.44
1963-1976	9.868 (10.65)	-2.746 (8.24)	.682 (2.04)	$R^2 = .98$ DW = 1.85	
1964-1976	9.868 (9.680)	-2.729 (-7.90)	.661 (1.90)	$R^2 = .98$ DW = 2.00	

(All equations were estimated in double logarithmic form)

*T-Statistics

Jet Fuel = Commercial Jet Fuel

PRM = Passenger revenue miles

ARPMAR = Average total passenger revenue per revenue passenger mile

YD72 = Real personal income (1972 dollars)

Pop = Population

Naptha and Liquid Gas Minor Fuels. Naptha and liquid gas, originally estimated as a single minor fuel, have been separated into different categories. Liquid gas feedstocks now include only raw materials usages of LPG and LRG, raw materials still gas, and miscellaneous raw materials.

An account of the data required for these new equation estimates is given in Section 2.B of the previous chapter.

Industrial naphthas were regressed in state corss-section on value added in SIC28 (chemicals). An autoregressive scheme was employed to remove autocorrelation of the residuals. Using pooled cross-section of time-series data, the state equations were estimated simultaneously with the coefficients (except the intercepts) constrained to be equal over states. The result of estimations was a national elasticity on value added in SIC 28 of .697 with acceptable Durbin-Watson statistics and acceptable R-squares. The R-squares for all states except California and Texas were above .65. All states which consumed industrial naphthas were included in the cross-section. Table 36 contains details of the estimation results.

Liquid gas feedstocks were regressed in state cross-section on the industrial liquid gas price and on value added in SIC28. As in the industrial naphthas, an autoregressive scheme was used to remove autocorrelation of the residuals. The state equations were estimated simultaneously with the coefficient constrained to be equal over states. The result of the estimation was a national elasticity on value added in SIC28 of .855 and a national price elasticity with respect to the industrial liquid gas price of -.863.

Table 36. Industrial Napthas Equation Estimates
(Coefficient, R-Squares, Durbin-Watsons, and
Standard Errors)

Variable SIC 28		Coefficient .697	
State	R-Sq.	D-W	S.E.
MI	.6567	1.3091	.1659
OH	.7485	1.4544	.1420
IL	.7076	1.4355	.1531
NJ	.6874	1.3638	.1583
NY	.7221	1.4507	.1493
MA	.8001	1.3464	.1266
PA	.7044	1.3990	.1540
TX	--	1.1059	3.3931
LA	.6581	1.2831	.1656
CA	.4402	.6839	.2119

R-squares in all states except Delaware and Kentucky were above .50. Table 37 contains details of the estimation results.

Table 38 summarizes specifications of the new equation estimates discussed in this and the previous subsections.

Table 37. Liquid Gas Feedstock Equation Estimates
(Coefficients, R-Squares, Durbin-Watsons, and
Standard Errors)

Variable SIC 28 Gas Price		Coefficient .855 -.863	
State	R-Sq.	D-W	S.E.
DE	.1280	.2845	.1787
KY	.2104	.2319	.1701
IL	.5734	.5386	.1250
IN	.6698	.3104	.1099
TX	.5158	.2788	.1333
IA	.8384	.4405	.0770
CA	.6256	.1708	.1171
LA	.7154	1.2878	.1021

Table 38. Summary of Jet Fuel, Industrial Napthas, and
Liquid Gas Relationships

Dependent Variables	Independent Variables
1. Per capita air passenger mile	Average total passenger revenues per revenue passenger mile; real per capital personal income
2. Commercial jet fuel	Per capita air passenger miles
3. Industrial napthas	Value added in SIC28
4. Liquid gas	Industrial liquid gas price; value added in SIC28

4. Comparison of RDFOR Results with Other Energy Demand Models

In this section parameter estimates obtained for RDFOR are compared with other studies of energy demand. Comparisons are made for the major fuel/sector categories and the transportation sector fuel demands. No critique of the various models is undertaken since that is beyond the scope of this analysis.

Residential Electricity. Table 39 presents a summary of the price and income elasticities, as well as the other characteristics, of selected residential electricity demand studies. This Table, as well as the ones included in the rest of this section, are based primarily on the surveys provided by Taylor (1976) and Slobod (1977) {6}.

The long-run price elasticities of the studies considered fall in the range of $-.52$ to -1.89 . Acton, et. al. (1975), Houthakker (1951) and Anderson (1972) find their long-run price elasticities to be less than unity but employ only cross-sectional data in their studies. However, Taylor, et. al., (1976) and Griffen (1974) use annual time series of states and also obtain long-run price elasticities less than unity. All of the other studies listed in Table 39 find long-run price elasticities to be elastic. These other studies employ either time series or pooled cross sections of time series. The elasticities for different DOE regions falling between $-.717$ and -2.093 . These results are consistent with both the time series findings stressing dynamic adjustments to fuel demand and the cross-sectional studies stressing regional variations in the determinants of demand.

Table 39. Residential Electricity Demand

Author	Price Elasticity		income Elasticity		Type of Study
	Short	Long	Short	Long	
Acton et. al. (1975)		-.70		.40	Cross-Sectional Data from The Los Angeles Department of Water and Power and Southern California Edison, 1972-1974. The Marginal Block Price Used to Estimate the Price Coefficient.
Ander-son (1972)		-.91		1.13	Cross-Section of States in 1969. The Average Price of Electricity Used to Estimate the Price Coefficient. The Price of Natural Gas Also included.
DOE (1977)	-.180 to -.538	-.717 to -2.093	.0 to .101	.0 to .3	See Previous Sections.
Fisher and Kayser (1962)	-.60			.40	Pooled Cross-Section (States) of Time Series (1946-1957). Stocks of Appliances incorporated into the Analysis in Order to Hold Constant The Effects of Electricity Using Durable Goods.
Griffen (1974)	-.06	-.52		.88	U.S. Time Series Data Used (annually). Lagged Effects of Average Electricity Price included. Simultaneity of Price Determination Considered.
Houth-akker (1951)		-.89		1.17	1937 Cross-Section of Towns in the United Kingdom. Two Part Pric-

					ing System Analyzed Using the Marginal Price of Electricity.
Houth- akker and Taylor (1970)	-.13	-1.89		1.94	U.S. Aggregate Time Series, 1947-64. Average Electricity Price Used along with Lagged Adjustment Mechanism.
Houth- akker, Verla- ger and Sheehan (1974)	-.09	-1.02		1.64	Pooled Cross-Section (States) of Time Series (1961-71). Marginal Price of Electricity Employed.
Mount, Chap- man and Tyrrell (1973)	-.35	-1.23		.18	Combined Cross-Section (States) and Time Series (1946-69). Average Price of Electricity and Price of Natural Gas Employed.
Taylor et. al. (1976)	-.07	-.78	.10	1.18	Time Series of States Used with the Marginal Price of Electricity (annual).
Uri (1975)	-.61	-1.66	.04	.12	U.S. Time Series Data Using Average Electricity Price (monthly).

The income elasticities vary widely from study to study with no apparent pattern as to type of data used (time series or cross-section).

The difference between marginal and average prices may be large in some cases where individual behavior is based on marginal prices. However, this problem may not be of great importance because aggregate data are used. Both average and marginal costs of purchasing services are important in determining aggregate demand. Average prices are important in making the decision whether or not to purchase at all while the marginal price is important in determining how much to purchase once the decision to purchase is made. The use of average costs include elements of fixed and marginal cost changes. The use of marginal costs correctly captures changes on the "intensive" margin, i.e.,

changes in quantity for those already purchasing electricity services. However, it does not capture changes in the "extensive" margin, i.e., new or potential demanders of electricity services.

Commercial Electricity. Table 40 presents a summary of price and income elasticities of electricity demand for the commercial sector for selected energy demand studies. DOE estimates of the long-run price elasticities are close to those obtained by Uri (1975) who did not use cross-sectional data and obtained the lowest long-run price elasticity estimate at $-.85$. The long-run income elasticities differ widely between studies with DOE estimates falling within the lowest range of zero to $.193$.

Table 40. Commercial Electricity Demand

Author	Price Elasticity		Income Elasticity		Type of Study
	Short	Long	Short	Long	
Mount, Chapman, and Tyrrell (1973)	-1.16	-1.42		.91	Combined cross-Sections (States) of Time Series (1946-1969). Average Prices of Electricity and Natural Gas Price included in the Specification.
DOE (1977)	-2.97 to -.622	-.934 to -1.935	.0 to .073	.0 to .193	See Previous Sections.
Uri (1975)	-.34	-.85	.79	1.98	U.S. Time Series Using Average Electricity Price (monthly).

Industrial Electricity. Table 41 presents a summary of price and income elasticities of electricity demand by the industrial sector for selected energy demand studies. The highest price elasticities are found by Anderson (1971), -1.94 ; Chern (1975), -1.98 ; and Mount, et. al. (1973), -1.72 .

Table 41. Industrial Electricity Demand

Author	Price Elasticity		Income Elasticity		Type of Study
	Short	Long	Short	Long	
Anderson (1971)		-1.94			Pooled Cross-Section of Electricity Consumption for Primary Metal industry (30 States) for 1958 and 1962. Average Price of Coal, Coke, and Oil included in The Specification.
Chern (1975)	-.61	-1.98		.97	Pooled Cross-Section (16 Three-digit Sic industries) of Time Series (1959-71). Average Price of Electricity, Prices of Gas, Coal, and Petroleum included.
DOE (1977)	-.170	-.746			See Previous Sections.
Fisher and Kaysen (1962)		0.0 to -2.6		.5 to 1.1	Cross-Section of Ten Manufacturing industries (1956) and Six Extractive industries (1954) Employed. Average Price of Electricity Used.
Griffen (1974)	-.04	-.51	.89		U.S. Time Series (annual). Average Electricity Employed Using Two Stage Least Squares.
Mount, Chapman, and Tyrell (1973)	-.21	-1.72		.54	Combined Cross-Section (States) of Time Series (1946-69). Average Price of Electricity and Natural Gas Employed.
Uri (1975)	-.35	-.69	1.32	2.63	U.S. Time Series Using Average Price of Electricity (monthly).

Natural Gas. Table 42 presents price and income elasticities of natural gas demand for selected econometric studies. The two studies of residential demand only, Anderson (1973) and DOE (1977), find that the long-run price elasticity of demand for natural gas is high. The DOE estimates vary between regions from $-.698$ to -1.745 while Anderson's estimate is 1.73 . Combining both residential and commercial demands, Balestra (1967), and Bundt and Watkins (1967) obtain long-run price elasticities less than unity, $-.70$ and $-.90$, respectively. The DOE commercial long-run demand elasticity is -1.057 , slightly higher than the estimates of Balestra, and Bundt and Watkins but lower than that for the residential sector only.

Anderson (1971) and MacAvoy and Noll (1973) use cross-section data sets and obtain elastic price elasticities of -1.98 and -1.78 , respectively. The DOE (1977) long-run price elasticity is $-.447$, which is based on cross-sections (states) of time-series.

Table 42. Natural Gas Demand

Author	Price Elasticity		Income Elasticity		Type of Study
	Short	Long	Short	Long	
Anderson (1971)		-1.98			Industrial Demand. Cross-Section of States Using Average Natural Gas Prices.
Anderson (1973)		-1.73			Residential Demand Analysis. Cross-Section (States) Using Average Natural Gas Price.
Balestra (1967)		-.70		.62	Residential-Commercial Demand. Cross-Sectional Time Series Using Variance Component Error Structure.
Bundt and Watkins	-.20	-.90	.04	.50	Residential-Commercial Demand. Variance Components Model Used to Estimate the Demand for Gas in Ontario and British Columbia. Average Gas Prices Used.
DOE (1977)	-.317	-1.057			Commercial Demand. See Previous Sections.
DOE (1977)	-.211	-.447			Industrial Demand. See Previous Sections.
DOE (1977)	-.221 to -.633	-.698 to -1.745			Residential Demand. See Previous Sections.
Macavoy and Noll (1973)		-1.78		.68	Industrial Demand. Cross- Section Data Set Using Pipeline Sales Contracts and Average Natural Gas Prices.

Distillate Oil Demand. Table 43 presents price and income elasticities of demand for distillate oil for selected econometric studies. Except for the DOE residential demand,

long-run price elasticities of all these studies are less than unity, around $-.6$.

Table 43. Distillate Oil Demand

Author	Price Elasticity		Income Elasticity		Type of Study
	Short	Long	Short	Long	
DOE (1977)	$-.19$	$-.892$			Commercial Demand.
	To	To			
	$-.36$	$-.69$			
	$-.215$	$-.536$			Industrial Demand.
	$-.185$	$-.960$			Residential Demand.
	To	To			
	$-.765$	-1.962			
Houthakker and Kennedy (1975)	$.39$	$-.76$	1.43	2.70	Cross-Section (Nine OECD Countries) of Time Series (Annual).
Verleger and Sheehan (1974)	$-.12$	$-.61$	$.12$	$.61$	Cross-Section (States) of Time Series (1967-72).

Residual Oil Demand. Table 44 presents a summary of price and income elasticities of demand for residual oil for selected studies. The Houthakker and Kennedy (1975) study finds price elasticities in the short and long run to be greater than unity, while the DOE model estimates these to be less than unity for both the commercial and industrial sectors.

Table 44. Residual Oil Demand

Author	Price Elasticity		Income Elasticity		Type of Study
	Short	Long	Short	Long	
DOE (1977)	-.220	-.987			Commercial Demand.
	-.133	-.727			Industrial Demand.
Houthakker and Kennedy (1975)	-1.05	-1.58	.40	.60	Cross-Section (Nine OECD Countries) of Time Series (annual).

Coal Demand. Table 45 shows the results of various econometric studies of coal demand. Both Lin (1976) and Reddy (1974) use time series data to estimate elasticities of demand. Their estimates are higher than those obtained by DOE using cross-sections of time-series.

Table 45. Coal Demand

Author	Price Elasticity		Income Elasticity		Type of Study
	Short	Long	Short	Long	
DOE (1977)	-.281	-.489			Industrial Demand. See Previous Section.
Lin (1976)		-.82		.31	Time Series of Appalachia.
Reddy (1974)	-.49	-2.07	-.05	-.22	Time Series of U.S. Data.

Transportation Demand. Table 46 presents the results of studies of the demand for gasoline. All the studies use aggregate U.S. time series data and obtain long-run price elasticities less than unity. Those obtaining income elasticities all find them to be greater than unity.

Table 46. Gasoline Demand

Author	Price Elasticity		Income Elasticity		Type of Study
	Short	Long	Short	Long	
DOE (1977)		-.48		1.19	Aggregate U.S. Time Series.
Houthakker and Taylor (1970)	-.14	-.48	.48	1.69	Aggregate U.S. Time Series.
Philips (1972)	-.12	-.68			Aggregate U.S. Time Series.
Ramsey et. al. (1975)		-.77		1.34	Aggregate U.S. Time Series.

{1}

The estimation procedure, discussed in Section 2 of this chapter, does indeed allow demand to vary across regions. If there are demand variations across regions (due to differences in the industrial composition of a region), the variable representing increased quantities of natural gas, GSC, may also represent an increased price of natural gas. In such a case the effect on use of other fuels is expected to be exactly the opposite, i.e., substitution away from natural gas. In other words, if supply is fixed between two regions but demand varies, the area with higher demand will exhibit a larger quantity and higher price of natural gas, leading to substitution away from natural gas toward consumption of other fuels.

{2}

Any lagged variables which are time as well as regionally subscripted will enter the analysis in a similar manner as those presented in (III-17).

{3} A. Zellner, "An Efficient Method of Estimating Seemingly Unrelated Regressions and Tests for Aggregation Bias," JASA, 57; and "Estimations for Seemingly Unrelated Regression Equations: Some Exact Finite Sample Results," JASA, 58.

{4} Civil Aeronautics Board, Handbook of Airline Statistics, Washington, D.C.: U.S. Government Printing Office, 1956 through 1970.

{5} See "TSCORC" in DOE TSP manual for further details.

{6} L.D. Taylor, "The Demand for Electricity: A Survey," The Bell Journal of Economics, Spring 75; and "The Demand for Energy: A Survey of Price and Income Elasticities," working paper prepared by the National Academy of Science Committee on Nuclear and Alternative Energy Systems, April 1976.

IV. SIMULATION

Simulation of RDFOR is primarily undertaken for two reasons: (1) to test the model's ability to track historical movements in fuel consumption and (2) to predict future fuel consumption patterns.

All simulations and forecasts are "deterministic" {1} and, for the most part, dynamic {2}. The technique utilized in both is "analytical" {3} and is based on the values of estimated elasticities, predicted (adjusted) regional intercepts, and predetermined variables.

This chapter addresses these and other related issues briefly. Section one presents an overview of the inputs required for a typical simulation run. Sections two through four discuss the details of these inputs and the various adjustments to them as they relate to the RDFOR simulation. The emphasis in each of these three sections is on the simulation aspects of the inputs, i.e., their derivation, projection, transformation, estimation, and adjustment. Section five outlines the structure of the simulation model and discusses its derivation from the estimating model. The last section presents a summary of the results and analyzes some of the prevalent issues.

1. An Overview of Simulation Inputs

The general form of a typical simulation model might be presented as:

$$(IV-1) \quad Y = f(b, X)$$

where upon encountering $Y(i)$ all $b(i)$'s and $X(i)$'s are known.

Granted that Equation IV-1 is a typical estimated econometric model, its right hand side is expected to contain one or more of the following: (1) exogenous variables, (2) current period endogenous variables, (3) lagged endogenous variables, and (4) parameters that have been statistically estimated. All these are represented by b and X in Equation IV-1.

Superimposing this simplified structure on the RDFOR model, the left hand side of the latter contains variables on energy consumption by region, consuming sector, and fuel type. These variables have been discussed in previous chapters. On the right

hand side of IV-1 representing RDFOR, the inputs (1) through (4) generally are present. To make this presentation manageable, discussion is limited only to the most significant factors of these four types of simulation inputs.

2. Exogenous Variables

Most important among this group are macroeconomic, demographic, weather, and price variables. Each of these will be discussed in turn.

Population, personal disposable income, and value added in manufacturing are the primary macroeconomic inputs provided to the demand model. The first two are the driving economic variables in the residential and commercial sectors and the last variable drives the industrial sector.

These inputs are provided on a DOE regional basis. In addition, certain variables needed to solve the transportation model equations at the national level are also provided. These variables include the unemployment rate, average wages per manhour, several FRB production indices, and structural variables on assumed future driving speeds and population of multiple truck rigs.

Ex-post simulations of the model are based on the historical values of these variables. These historical values constitute a portion of the data base used in the estimation step and they are fully documented in the chapter on data sources.

The ex-ante simulations of the model utilize projections of the macro variables based on the average historical growth rates and DRI long-term projections. The regional projections of the macro variables are derived by applying the 1974 regional share projections of the Survey of Current Business to the DRI figures. The national projections are for the most part simply DRI forecasts. See Appendix B of National Energy Outlook 1976.

Since the time patterns of macro variables are usually stable, their projections are generally simple. This is not the case for other exogenous variables, particularly those that fluctuate randomly or have future paths which are indeterminable in advance. Among this group, weather variables are noteworthy. Due to the lack of long-term weather predictability, projections of weather trends are based on the assumption that weather maintains its historical average values. For the base year, weather adjustments are necessary to make the 1975 consumptions correspond with the mild 1975 weather. The magnitude of these adjustments is obtained by using the estimated elasticities for

cooling and heating degree days and comparing the 1975 consumption figures with their corresponding values obtained on the basis of normal weather. These weather effects are incorporated into the constant terms.

The price data in ex-post simulations are taken directly from the demand model consumption data base used in the parameter estimations. The historical prices used are for the years 1973, 1974, and 1975. The latter year is used as the initial point in the price trajectory, and the other two years are needed to calculate lagged values for the simulation equations.

The price paths used in the ex-ante simulations are generated by a linear interpolation between the last historical period price (1975) and the 1985 PIES forecast for a comparable scenario run. Note that PIES prices are "endogenously" determined in the equilibrium process of the PIES system. To this extent, this straight jacket projection of prices is not completely arbitrary.

The prices for which price paths are drawn are for 18 fuels (see Table 2 for a list of these fuels). All of the prices appear directly in the data base, except for distillate fuel, jet fuel, and residual fuel in the transportation sector. These prices are constructed by adding transportation fuel taxes to the industrial prices of distillate, kerosene and residual oil, respectively.

Specific attention has been paid to the price of residential and industrial electricity. Historically, the differential between these two prices has been decreasing. The forces which generated this leveling can be expected to continue. This means that, whereas constant real markups over time are assumed for all other fuels, the residential electricity price is anticipated to be closer to the industrial price in 1985 than it is now. The 1980, 1985, and 1990 electricity differentials are derived by projecting log-linear time trends of the differential between the average electricity price and each of the sectoral prices.

Each final PIES solution which uses demand model prices, quantities and elasticities as inputs, generates values for each of the 18 prices at the energy equilibrium. These prices are then used as targets for the linear extrapolation of the price paths. Three different extrapolations are considered: (a) dog-leg, (b) ramp, and (c) stair-step. These are demonstrated in Figure 13. The choice between these three methods of price calculation is somewhat subjective. The first--dog-leg price paths--was utilized in the 1976 version of RDFOR. The second--ramp price construction--is preferred in the 1977 version since it appears to be more consistent with the intertemporal price patterns used in the revised Oil and Gas Supply Model.

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3. Current and Lagged Period Endogenous Variables

Current and lagged period endogenous variables appearing on the right hand side of Equation IV-1, are treated simultaneously here since they are both "known" endogenous variables in the simulation stream. The first group, i.e., current endogenous variables, should pose no problem in an analytical simulation design. Upon encountering each equation for the simulation purpose, these variables are either already determined within the simulation program or are non-existent because the model is already analytically solved for its unknowns. The second group, if present, consists primarily of region-sector-type specific fuel consumptions that are lagged one or two periods. Since the lag structure of this group of variables is central to the dynamic behavior of the model, the remaining part of this section concentrates on these variables.

Since the 1977 version of RDFOR is initialized to 1975 values, determine the 1976 level of demand are the 1974 and 1975 values. These are known a priori and are generally provided by their historical values.

When forecasting future energy consumption, the method for determining the paths of lagged endogenous variables and indices poses some problems. In a truly dynamic case, values of these variables are supplied intact by the simulated values of the prior period(s). This approach, which sometimes generates unrealistic results, provides the most stringent test of the performance of a model.

Notwithstanding its troubles, the above approach is enlightening and is of interest when we consider a somewhat related issue pertaining to the choice of values for the lagged total quantity index, $TQI(-1)$. Lagged values of this index are calculated in two ways: (1) from the simulating equation for total energy and (2) from the individual values of the fuel simulating equations. If we designate the former by $TQI(-1)$ and the latter by $TQM(-1)$, the choice of dynamics is the selection of $TQI(-1)$ or $TQM(-1)$ as the lagged value in simulating equations. The divergence of these two forms of the index is much less in the NEO/77 simulations than in the NEO/76. In the latter case there has been considerable experimentation with combinations of these two forms. The form that most closely resembles the estimation period structure is finally selected for simulation.

It is important to note that the choice of the lagged index will have differential effects in the simulating equations since it appears in the numerator of the total energy equations and in the

denominator of the fuel ratio equation. The reason for the difference between $TQI(-1)$ and $TQM(-1)$ is twofold. First, the values of the fuel equations are not determined simultaneously with the total energy values. Second, there is no mechanism in the model to adjust the fuel values to produce the forecasted TQI .

Another point relates to the fact that the forecast of the total major fuel quantity index (TQ) depends upon the "current" level of the total fuel price index (TP). The difficulty is that this index cannot be derived for the current period without knowing the current share quantities of the fuels in the index. Fuel prices for individual fuels are inputs to the simulation program, so they are known, but fuel quantities for the individual fuels are derived as shares of TQ (which depends upon TP). TP is approximated by setting fuel quantity shares in the index to last period's share quantities. This will affect the dynamics of the model.

4. Estimated Parameters

The econometric parameter estimates used by the simulating equations are obtained from three separate estimated submodels. The first submodel produces estimates of demand elasticities for the residential, commercial, and industrial sectors using a reduced form model of intraregional fuel substitution. The second submodel produces demands for fuels in the transportation sector using structural models of national use of various transportation modes. The third submodel is a collection of equations which generates demand parameters for the remaining consumption covered by the model, mostly industrial raw materials and feedstocks.

The estimated parameters determine the responsiveness of each of the simulating equations to various predetermined inputs. These parameters remain invariant across scenarios. They are the result of the estimation of historical demand relationships which underlie the variation in demand conditions over the last 15 years and across the various states or regions included in the estimations.

Due to the special treatment of some of the estimated parameters in the simulation model, we categorize them into two groups: (1) estimated intercepts and (2) other estimated parameters. Each will be discussed in turn.

The estimated intercepts determine the initial (or unadjusted) positions of the demand curves. Once the slope of each demand curve is determined, its position can be adjusted for specific

scenario demand shifts. These demand shifts are generally of two distinct types. The first type is a demand offset which represents a shift from one method of satisfying the underlying energy demand to another. Demand offsets for solar and geothermal replacement of traditional fuels is one example. The exogenous shift of the demand curve for natural gas and the concomitant countershift in substitute fuels which occurs in the Deregulation Scenarios is another. The second type of demand shift is the exogenous reduction in the underlying energy demand that results from such conservation initiatives as the DOE . Management Program or the weather programs.

Each one of these two types of demand shifts is incorporated into the demand equation by adjusting the relevant intercepts. This implies that the position of the demand curve for a given fuel is shifted by the same percentage amount at all prices.

Section two of this chapter pointed out some adjustments to the estimated intercepts due to the omission of weather variables in simulation. Other adjustments to the intercepts result from the benchmarking procedure employed. Figure 14 clarifies this point. At $x(1)$, $y'(1)$ is the predicted value and $y(1)$ is the actual value. To start the model from point $y(1)$, rather than $y'(1)$ requires an adjustment of the coefficient a .

Due to the differences between the estimating and simulating equations, some adjustments to the estimated intercepts are necessary before the simulation equations can be solved. In NEO/76, the intercepts were benchmarked to the geometric average of the 1973 and 1974 actual values. The rationale for this was that both these years had large and opposite transitory components which were not typical of the rest of the sample or the underlying economic relationships. The averaging was a rough method of correcting for this.

With the benefit of 1975 data, which represents a much more typical year than the previous two, the averaging does not seem necessary. The 1975 values are thus used to benchmark the simulating equations i.e., the intercepts of the simulating equations are calculated to reproduce the 1975 actual values. Benchmarking against the predicted rather than the actual values is attempted but has not produced reasonable results. The forecasted values turn out unacceptably below the actual values for 1975, probably because of the interaction between the perversities of the previous two years and the dynamics of the model.

The estimated non-intercept parameters are all converted to elasticities. The RDFOR simulation code is designed to compute elasticities for all fuels (including aggregate elasticities to be used in the iterative solution procedure of the integrating model) for all years beginning with the first simulation year (1976).

Figure 14.

Elasticities are numerically computed rather than analytically derived. Since the demand model is actually a collection of several differently constructed sub-models, analytical derivation of elasticities cannot be handled in a standard way across all fuels, but necessarily changes with the elasticity being derived. Moreover, the analytical derivation of the elasticity expressions for the major fuels equations is more complex because of the lag structures of the total energy and fuel/ratio equations and the variable weights in the indices.

Procedurally, RDFOR is solved completely for a set of base level prices and the results are stored as a base case solution. Then, step by step, a price or group of prices is perturbed by + 10 percent in 1990 and new prices (ramp paths) are constructed for use in the simulation period. The model is solved again and stored separately. The elasticities for the perturbation are then calculated by examining differences between the two model solutions.

Figure 15 demonstrates a form of this price perturbation. The dashed line shows the price path used for comparison with the base run. The price perturbation groups which the model calculates are listed in Table 47.

Table 47. Price Perturbation Groups

Perturbation	Fuel Group	Code from Table II.2
1	Gasoline	15
2	Electricity	1, 5, 9
3	Natural Gas	2, 6, 10
4	Distillate	3, 7, 11, 16
5	Residual	8, 12, 18
6	Liquid Gases	4, 13
7	Jet Fuel	17
8	Coal	14
9	Oil	3, 4, 7, 8, 11, 12, 13, 15, 16, 17, 18
10	All Fuels	

Elasticities are calculated as the difference between the logarithms of the quantity-price ratios for the perturbed and unperturbed demand points. The following logarithmic approximation formula is used to compute each elasticity:

Figure 15.

$$(IV-2) \quad E(NT, K, I) = \ln(QPTB(I, K, NT) / QBASE(K, NT)) / \\ (1.1) ** ((NT - NO) / (NTK - NO))$$

For: NT = N1, NTK
N1 = NO + 1

Where: NT = year
K = fuel
I = price perturbation
NO = 1975, generally
N1 = 1976, generally
NTK = 1990
QPTB = perturbed quantity
QBASE = base quantity

1.1 = ratio of PPTB/PBASE in 1990.

For a given target year Equation IV-2 gives the predicted percent change in demand for a given fuel if a given energy price change were rolled in so that the price was one percent higher in the target year.

The log-linearity of the model equations permits a single perturbation to be used to define a gradient of the demand surface for the entire range of possible prices. Some non-linearities in the automobile gasoline model mean that the approximation is not exact, but additional test perturbations indicate that the error is small. It is important to notice that the elasticities derived by perturbing the price path are intertemporal elasticities. A short-run elasticity would be derived by perturbing the price only in the target year and measuring the quantity change in that year. However, the PIES equilibrating mechanism represents price changes that are rolled in over time, hence the intertemporal elasticity is the relevant concept.

5. Structure of the Simulation Model

The structure of the simulation model differs from that of the estimation. The simulating equations are the algebraic transformation of the "deterministic" part of the stochastic estimating equations with several modifications. The form of the simulating equations for the residential, commercial, and industrial sectors appears below:

$$(IV-3) \quad TQ = a (TP^{**b}) (YPERM^{**g}) (YPERM(-1)^{**h}) \\ (TQ(-1)^{**d}) POP$$

$$(IV-4) \quad (Q/TQ) = a ((P/TP)^{**b}) ((Q/TQ(-1))^{**d})$$

where YPERM represents permanent disposable income, Q is fuel consumption, TQ and TP are geometric quantity and price indices, respectively, and the other symbols represent parameters.

Equations IV-3 and IV-4 do not contain error terms and are not in per capita form like the estimating equations. In addition, there are no weather or gas availability variables in the simulating equations. Finally, the autoregressive adjustment does not appear in these equations. The justifications for these exclusions follow.

First, the length of the time horizon of the simulation is sufficiently long to mitigate against forecasts of heating and cooling degree days. Furthermore, scenario variations involving weather conditions are not part of the mandate of this modeling effort.

Second, the gas availability variables are difficult to project and, more importantly, the quality of the historical availability data, namely gas service customers, is not sufficiently good to produce reliable elasticity estimates. In general, the computed gas service customers elasticities are too small to produce significant variations across scenario results. Consequently, an alternative strategy for modifying gas availability is employed and is discussed below.

Finally, the exclusion of the autoregressive adjustment is justified on the grounds that the sample period adjustment corrects for errors in measurement which are not continued into the simulation period. The alternative hypothesis of error specification in the equation also deserves some support; it would indicate continuation of the adjustment. However this hypothesis is probably less pronounced than the errors in measurement hypothesis.

As pointed out in the discussion of parameters, the result of the exclusions of these variables in the simulating equations is that the estimated intercepts are no longer valid for the modified form. In addition, the exclusion means that the lagged values to be used in the intercept calculation and the initial year solution of the equations should be adjusted. These points are already fully discussed in sections two through four of this chapter.

The simulation period differs from the estimation period in another respect. In the estimation period the actual values for fuel consumption were known for each year in the sample and hence

the quantity indices, TQ , in Equation IV-3 and IV-4 could be computed from actual values. This is not true in the simulation period since the predicted index is used to compute the fuel quantities and may not agree with the posterior index constructed after the quantities are known. Therefore, there is a choice of using the last period's predicted index or the posterior index. This problem is already discussed in the section on the current and lagged period endogenous variables.

6. Empirical Results of the Simulation Model

The simulation model combines the inputs discussed in the preceding sections and produces annual demand forecasts for 1976 through 1990 for 30 fuel/sector pairs in the 10 DOE regions. The model also generates regional elasticity arrays for each year which contain the anticipated percent changes in each of the 18 prices. The level of detail of the simulation model is indicated in Table 48.

Apart from forecasting and elasticity generating, the simulation model can be used in various policy analyses and scenario implementations. Several of the scenarios which are run through the PIES system are initiated by the implementation of alternative specifications in the demand model. In general, these scenarios are based on a combination of structural demand shifts and direct demand or exogenous shifts. A list of some of these scenarios and the mix of their structural and demand components is presented in Table 49.

Table 48. Fuel/Sector Detail Modeled in the Demand Model

Code	Description	1975 Share	Price Sensitivity
1	ELRS Residential Electricity	.0374	Joint
2	NGRS Residential Natural Gas	.0937	Joint
3	DFRS Residential Distillate Fuel	.0418	Joint
4	LGRS Residential Liquid Gases	.0107	Joint
5	ELCM Commercial Electricity	.0310	Joint
6	NGCM Commercial Natural Gas	.0475	Joint
7	DFCM Commercial Distillate Fuel	.0816	Joint
8	RFCM Commercial Residual Fuel	.0187	Joint
9	ELIN Industrial Electricity	.0427	Joint
10	NGIN Industrial Natural Gas	.1395	Joint
11	DFIN Industrial Distillate Fuel Oil	.0090	Joint
12	RFIN Industrial Residual Fuel Oil	.0151	Joint
13	LGIN Industrial Liquid Gases	.0063	Joint
14	CLIN Industrial Coal	.0261	Joint
15	GSTR Transportation Gasoline	.2410	Own-joint
16	DFTR Transportation Distillate Fuel Oil	.0440	Own-joint
17	JFTR Transportation Jet Fuel	.0337	Own
18	RFTR Transportation Residual Fuel Oil	.0137	None
19	ELTR Transportation Electricity	.0002	None
20	NGRM Raw Materials Natural Gas	.0127	None
21	LGCM Commercial Liquid Gases	.0013	Own
22	LGTR Transportation Liquid Gases	.0003	None
23	LGFS Feedstocks Liquid Gases	.0296	None
24	LGRM Raw Materials Liquid Gases	.0028	None
25	OLRM Raw Materials Oil	.0098	None
26	PCIN Industrial Petroleum Coke	.0069	None
27	ASCM Commercial Asphalt	.0195	Gasoline
28	CLHC Household/Commercial Coal	.0034	None
29	CLTR Transportation Coal	.0000	None
30	MCIN Industrial Metallurgical Coal	.0430	None
31	ELTT Total Electricity	.1113	
32	NGTT Total Natural Gases	.2934	
33	DFTT Total Distillate Fuel Oil	.1031	
34	RFTT Residual Fuel Oil	.0475	
35	LGTT Total Liquid Gases	.0511	
36	OPTT Total Other Petroleum Projects	.0362	
37	OLTT Total Oil	.5229	
38	CLTT Total Coal	.0725	
39	TTRS Residential All Fuels	.1869	
40	TTCM Commercial All Fuels	.1366	
41	TTIN Industrial All Fuels	.3435	
42	TTTR Transportation All Fuels	.3330	
43	TTTT Total All Fuels	1.0000	

Table 49. Details of Scenarios Implemented through the Demand Model

Scenario	Direct Shifts		Structural Shifts		
	Exogenous Conservation	Solar/Geother-Mal	Auto Mpg Stand-Ard	Cab Load Factor	Natl. Gas Deregulation
Calibration	(None)	(None)	No	No	Regulate
Reference	REF	REF	Low	No	Regulate
Accelerated	ACC	ACC	Hi	Yes	Regulate
Low Economic Growth	REF	REF	Low	No	Regulate
High Imports	(None)	(None)	No	No	Regulate
Low Imports	ACC	ACC	Hi	Yes	Deregulate
Deregulation	REF	REF	Low	No	Deregulate
Zero Conservation	(None)	REF	Low	No	Regulate

The structural shifts either (1) modify the RDFOR input files or (2) impose parametric changes within the model. An example of (1) is the imposition of a miles per gallon standard in the automobile simulation model. An example of (2) is the adjustment of the load factor for commercial airlines to conform to a Civil Aeronautics Board (CAB) standard of 65 percent. Tables 51 through 53 present the actual values used in these examples and their respective effects on energy use.

The exogenous shifts take two forms: (1) conservation reductions and (2) demand offsets. The results of an exogenous shift of form (1)--the reductions for the Reference and Accelerated Conservation Scenarios--are shown in Table 54. The details of the programs that are expected to generate these savings are discussed elsewhere {4}. The results of an exogenous shift of form (2)--the demand offsets including direct solar and assumed to be conserved for solar and geothermal offsets since they can only be measured against the fuels they are replacing. However, there is a slight Btu (loss/gain) when natural gas becomes more available as a result of the termination of hookup moratoria. This is due to the varying end use efficiency of the substitute fuels.

Table 01. Reference Case & Accelerated Case MPG Standard

Year	Reference	Accelerated
1976	--	--
1977	--	--
1978	18.0	18.0
1979	19.0	19.0
1980	20.0	20.0
1981	21.2	21.5
1982	22.4	23.0
1983	23.6	24.5
1984	24.8	26.0
1985	26.0	27.5
1986	26.0	27.5
1987	26.0	27.5
1988	26.0	27.5
1989	26.0	27.5
1990	26.0	27.5

Table 51. Efficiency Standard Effects on New Car MPG, Average MPG and Gasoline Consumption for 1985

	New Car Mpg	Average Mpg	Gasoline Cons.
Calibration	18.8	17.2	10800 Tbtu
Reference	26.0	20.1	9400 Tbtu
Accelerated	27.5	20.5	9235 Tbtu

Table 52. Cab Load Factor Effects on Air Passenger Miles and Jet Fuel Consumption for 1985

	Air Revenue Passenger Miles (billions)	Commercial Jet Fuel Consumption
Calibration	368	2740 Tbtu
Accelerated	368	2490 Tbtu

Table 53. Conservation Savings by Sector

	Coal	Oil	Natural Gas	Electricity	Total
Conservation Savings 1980 Reference Case, Tbtu's					
Residential	12.139	26.231	150.269	108.357	296.996
Commercial	0.000	88.567	86.902	69.860	245.329
Industrial	10.643	12.261	64.636	24.853	112.393
Transportation	0.000	373.400	0.000	0.000	373.400
Total	22.782	500.459	301.807	203.070	1028.117
Conservation Savings 1980 Accelerated Case, Tbtu's					
Residential	7.228	86.723	443.812	158.613	696.376
Commercial	0.000	139.019	135.338	108.572	382.929
Industrial	42.873	67.839	260.378	100.116	471.206
Transportation	0.000	487.312	0.000	0.000	487.312
Total	50.101	780.892	839.528	367.301	2037.822
Conservation Savings 1985 Reference Case, Tbtu's					
Residential	7.506	37.032	170.525	238.884	453.897
Commercial	0.000	121.070	106.012	114.701	341.783
Industrial	4.924	6.703	30.983	12.613	55.223
Transportation	0.000	422.667	0.000	0.000	422.667
Total	12.430	587.472	307.520	366.148	1273.569
Conservation Savings 1985 Accelerated Case, Tbtu's					
Residential	8.005	129.297	508.477	376.571	1022.349
Commercial	0.000	319.168	290.382	330.943	940.493
Industrial	83.904	151.482	528.953	215.245	979.584
Transportation	0.000	535.774	0.000	0.000	535.774
Total	91.909	1135.720	1327.012	922.759	3478.200
Conservation Savings 1990 Reference Case, Tbtu's					
Residential	5.090	39.630	99.200	375.368	519.288
Commercial	0.000	166.172	136.316	179.290	481.778
Industrial	0.000	0.000	0.000	0.0000	0.000
Transportation	0.000	474.375	0.000	0.000	474.375
Total	5.090	680.177	235.516	554.658	1475.440
Conservation Savings 1990 Accelerated Case, Tbtu's					
Residential	7.845	195.915	468.841	603.593	1276.194
Commercial	0.000	534.358	456.716	627.810	1618.883
Industrial	79.094	161.972	509.323	213.094	963.483
Transportation	0.000	602.626	0.000	0.000	602.626
Total	86.939	1494.870	1434.880	1444.497	4461.184

Table 54. Demand Shifts for Solar and Geothermal Sources

	Coal	Oil	Natural Gas	Electricity	Total
Solar/geothermal Substitutions 1980 Reference Case, Tbtu's					
Residential	0.0	0.0	0.0	0.0	0.0
Commercial	0.0	0.0	0.0	0.0	0.0
Industrial	0.0	0.0	0.0	0.0	0.0
Transportation	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0
Solar/geothermal Substitutions 1980 Accelerated Case, Tbtu's					
Residential	0.0	0.0	0.0	0.0	0.0
Commercial	0.0	0.0	0.0	0.0	0.0
Industrial	0.0	0.0	0.0	0.0	0.0
Transportation	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.0
Solar/geothermal Substitutions 1985 Reference Case, Tbtu's					
Residential	0.286	25.206	47.007	28.130	98.629
Commercial	0.000	9.174	18.898	20.360	48.432
Industrial	2.959	11.464	40.021	14.493	68.937
Transportation	0.000	0.000	0.000	0.000	0.000
Total	3.245	45.844	103.926	62.983	214.998
Solar/geothermal Substitutions 1985 Accelerated Case, Tbtu's					
Residential	0.908	87.035	156.973	98.512	343.428
Commercial	0.000	21.584	32.979	37.070	91.633
Industrial	2.959	11.464	40.021	14.493	68.937
Transportation	0.000	0.000	0.000	0.000	0.000
Total	3.867	120.083	229.973	150.075	503.998
Solar/geothermal Substitutions 1990 Reference Case, Tbtu's					
Residential	0.899	137.570	213.516	158.056	510.041
Commercial	0.000	37.804	54.903	68.568	161.275
Industrial	7.697	31.807	101.587	36.592	177.683
Transportation	0.000	0.000	0.000	0.000	0.000
Total	8.596	207.181	370.006	263.216	848.999
Solar/geothermal Substitutions 1990 Accelerated Case, Tbtu's					
Residential	2.332	353.087	551.896	410.251	1317.566
Commercial	0.000	87.416	113.768	145.485	346.669
Industrial	12.383	51.084	162.727	58.569	284.763
Transportation	0.000	0.000	0.000	0.000	0.000
Total	14.715	491.587	828.391	614.305	1948.997

[1]

As opposed to "stochastic."

[2]

Benchmarking is done only in the base period and predicted values of variables are used throughout thereafter.

[3]

No iterative procedure is required since analytical solution is already obtained

[4]

See U.S. Department of Energy, National Energy Outlook 1977, Washington, D.C.: DOE, 1977, Appendix I.