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Short-Term Energy Outlook
Annual Supplement 1995

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Environmental Regulations and Changes in the Petroleum Refining Operation . . . . Tancred Lidderdale

Comparison of EIA and Other Forecasts for 1995 and 1996 . . . . Michael Morris

Forecast Evaluation . . . . Neil Gamson

Oxygenate Supply/Demand Balances in the Short-Term Integrated Forecasting Model . . . . Tancred Lidderdale

An Econometric Analysis of Short-Term Interfuel Substitution in the United States . . . . Timothy J. Considine

Contents

Tables

Figures

1. Introduction

The *Short-Term Energy Outlook Annual Supplement (Supplement)* is published once a year as a complement to the *Short-Term Energy Outlook (Outlook), Quarterly Projections.* The purpose of the *Supplement* is to review the accuracy of the forecasts published in the *Outlook*, make comparisons with other independent energy forecasts, and examine current energy topics that affect the forecasts. A brief description of the content of each chapter follows below:

Chapter 2 provides an analysis of the response of the U.S petroleum industry to the recent four Federal environmental rules on motor gasoline. These rules are: Phase I summer volatility regulation, Phase II summer volatility regulations, Oxygenated gasoline mandates, and reformulated gasoline requirements. This chapter analyzes how these rules have affected domestic refining operations and inventory patterns. In addition, this chapter discusses the price effect of these rules as well as changes in motor vehicle fuel efficiency that has occurred as a result of the regulations.

Chapter 3 compares the Energy Information Administration's (EIA) base or "mid" case energy projections for 1995 and 1996 as published in the first quarter 1995 *Outlook* with recent projections made by four other major forecasting groups. The chapter focuses on macroeconomic assumptions, primary energy demand, and primary energy supply, showing the differences and similarities in the five forecasts. Although there are more similarities than differences, the EIA forecasts tended be on the low side compared to the other forecasts for prices, economic growth and petroleum demand.

Chapter 4 evaluates the overall accuracy of the short-term energy forecasts published in the third quarter 1993 *Outlook* through the fourth quarter 1994 *Outlook*. The energy forecasts evaluated for petroleum include: prices, demand, production, imports, and stocks. Forecasts for demand and production of natural gas and coal are also evaluated, as well as electricity sales and generation forecasts. The period of this evaluation is the third quarter 1993 through the end of 1994. This period covers generally declining natural gas prices, but at the same time, relatively low world oil prices. In addition, there are evaluations of one-year-ahead forecasts for several major energy variables for 1986 through 1994 thereby adding an historical depth to the analysis.

Chapter 5 presents the methodology the Short-Term Integrating Forecasting System (STIFS) uses to project oxygenate production, imports, inventories, and demand for motor gasoline. The Clean Air Act of 1990 required the use of oxygenates primarily during the winter months to reduce carbon monoxide emissions in metropolitan areas.

Chapter 6 reports theoretical and empirical results from a study of non-transportation energy demand by sector, using a linear logit formulation to determine cost shares for various fuels. We prove that the linear logit model of cost shares avoids curvature problems often associated with estimating nonlinear relationships with flexible functional forms. The linear logit model yields downward sloping demand curves at all observations if the curvature conditions are satisfied at a base point of approximation.

Our empirical analysis involves the short-run demand for energy in the residential, commercial, industrial, and electric utility sectors in the United States. EIA estimates the models with monthly data with large seasonal variation in cost shares, a method leading to curvature violations in the translog model. With the logit model, however, the demand curves have proper curvature across all four sectors for all observations. We estimate very limited substitution possibilities between fuels in the residential and commercial sectors but considerably greater substitution in the industrial and electric utility sectors. Model simulations demonstrate a superior fit over the sample period, stable projections out of sample, and sensible responses in fuel demands to weather, income, and output shocks.

2. Environmental Regulations and Changes in the Petroleum Refining Operations

Introduction

The U.S. petroleum industry has responded to 4 major new federal rules on motor gasoline product quality in the last 6 years:

Environmental Regulations Affecting the Product Quality of U.S. Motor Gasoline

Phase I Summer Volatility (RVP) Regulation	June 1989
Phase II Summer Volatility (RVP) Regulation	May 1992
Oxygenated Gasoline	November 1992
Reformulated Gasoline Phase I Simple Model	December 1994

These regulations have generated significant changes in domestic refinery operations, affecting marginal production costs and market prices, refinery yields, and the seasonality of production. Some changes have been dramatic. The price of motor gasoline has increased by as much as 6 cents per gallon because of the regulations. Refinery yields of motor gasoline (refinery output of motor gasoline as a fraction of refinery inputs or total refinery output), which historically peaked in the early summer to meet high summer driving demand, now are highest during the winter months. These changes in domestic refining operations are identified and related to the Reid vapor pressure (RVP) and oxygenated gasoline product quality regulations. This analysis uses linear regression equations from the *Short-Term Integrated Forecasting System (STIFS)*. The *STIFS* model is used for producing forecasts appearing in the *Short-Term Energy Outlook.*

This analysis is important to forecasters who wish to evaluate the accuracy and robustness of their predictive models of industry behavior. In particular, the changes in motor gasoline product quality mandated by the RVP and oxygenated gasoline regulations are similar to the changes required by the new reformulated gasoline program. These observations are also important to petroleum market participants and the industry press because current market survey data are often compared with historical market survey data to evaluate current market conditions. The motor gasoline product quality regulations require significant changes in refining industry operations and current market conditions may not be directly comparable to those of recent history.

Motor Gasoline Summer Volatility (RVP) Regulations

The Environmental Protection Agency (EPA) implemented a two-phase program to reduce summertime gasoline volatility measured as Reid vapor pressure (RVP). Phase I of the RVP regulations went into effect on June 1, 1989, and Phase II became effective on May 1, 1992 (Table 1). The new RVP standards were established for each of the 48 contiguous States during the summer months of May 1 through September 15.

The reduction in allowable RVP affects the supply, demand, and price of motor gasoline. Refiners lower RVP by reducing the volume of high RVP components in motor gasoline, such as normal butane. Motor gasoline supply is affected because, for a given volume of refinery inputs, less finished motor gasoline will be produced. The price of motor gasoline should be higher because normal butane and other low cost blendstocks that have a high RVP must be removed from the motor gasoline pool. Finally, consumer demand for motor gasoline should be lower because reducing motor gasoline RVP improves motor vehicle fuel economy through increases in the motor gasoline

Table 1. **Summer Volatility Regulations for Motor Gasoline**
(Pounds per Square Inch Reid Vapor Pressure)

Region	ASTM Class	Before June 1, 1989	RVP Phase I June 1, 1989 to April 30, 1992	RVP Phase II May 1, 1992 to January 1, 1995
Ozone Attainment Areas:				
Northern U.S.	C	11.5	10.5*	9.0
Southern U.S.	B	10.5	9.5	9.0
Southern U.S.	A	9.0	9.0	9.0
Ozone Nonattainment Areas:				
Northern U.S.	C	11.5	10.5*	9.0
Southern U.S.	B	10.5	9.5	7.8
Southern U.S.	A	9.0	9.0	7.8

Notes: Enforcement begins on June 1 for retail stations. Enforcement begins on May 1 for all other points in the distribution system, including refiners and importers, pipelines, and terminals. Enforcement ends on September 15 at all points in the system, including service stations.
* Northeast States for Coordinated Air Use Management (NESCAUM), which includes Connecticut, Massachusetts, New Jersey, New York, and Rhode Island, implemented the Phase II 9.0 RVP specification for gasoline beginning June 1, 1989.
Sources: Phase I gasoline volatility regulation announced by EPA in *Federal Register*, Vol. 54, No. 54 (Washington, DC, March 22, 1989), p. 11868. Phase II gasoline volatility regulation announced in *Federal Register*, Vol. 55, No. 112 (Washington, DC, June 11, 1990), p. 23658. The Phase II regulations were revised to conform to the requirements of the Clean Air Act Amendments of 1990 and announced in *Federal Register*, Vol. 56, No. 239 (Washington, DC, December 12, 1991), p. 64704.

energy density (Btu per gallon) and less fuel loss through evaporation.

Net refinery inputs of LPGs declined by 54,000 barrels per day during the Phase I RVP Control Season and fell by an additional 52,000 barrels per day during Phase II.

The primary methods refiners have for lowering RVP are reducing the volume of normal butane, a liquefied petroleum gas (LPG), blended into motor gasoline or increasing the volume of normal butane rejected from motor gasoline through distillation. Thus, refiners are expected to reduce *net* refinery inputs of normal butane, which is defined as refinery inputs of normal butane minus refinery outputs of normal butane. About 2 gallons of normal butane must be removed from 100 gallons of motor gasoline to reduce the RVP by 1 pound(s) per square inch (psi) based on a simple linear blending calculation.[1] Domestic refinery production of motor gasoline averaged about 7.2 million barrels per day during the Phase I RVP controls.[2] Lowering average RVP by 1 psi on all domestic motor gasoline production would reduce net refinery inputs of normal butane by up to 140 thousand barrels per day.

EIA surveys (*Petroleum Supply Reporting System*) show net refinery inputs of butane declined by 80,000 barrels per day during the Phase I summer RVP control season (April through August 1989, 1990, and 1991) compared with net refinery inputs during the preceding three-year period (Table 2). The Phase II RVP control season (1992, 1993, and 1994) saw an additional reduction in net refinery inputs of normal butane of 55,000 barrels per day.

While the observed declines in net refinery inputs of normal butane are consistent with the expected effects of RVP controls, changes in other operating conditions, such as crude oil feed rates or gasoline yields, which may not be related to the environmental regulations, could be responsible. To control for other changes, ordinary least squares regression analyses of refinery inputs and refinery outputs of liquefied petroleum gas (LPG) were made (Appendices A.1 and A.2). The regression results indicate changes in net refinery inputs of LPGs associated with the RVP regulations are consistent with the direction of changes in net refinery inputs of normal butane presented above. The

Table 2. Refinery Inputs and Outputs of Normal Butane
(Million Barrels per Day)

	Refinery Inputs	Refinery Outputs	Net Refinery Inputs (Inputs-Outputs)
No RVP Regulations:			
April 1986 - August 1986	0.102	0.111	- 0.009
April 1987 - August 1987	0.107	0.120	- 0.013
April 1988 - August 1988	0.101	0.131	- 0.030
Summer 1986 - 1988 Average	0.103	0.121	- 0.017
Phase I RVP Controls:			
April 1989 - August 1989	0.069	0.191	- 0.122
April 1990 - August 1990	0.056	0.136	- 0.080
April 1991 - August 1991	0.078	0.168	- 0.090
Summer 1989 - 1991 Average	0.068	0.165	- 0.097
Phase II RVP Controls:			
April 1992 - August 1992	0.071	0.224	- 0.153
April 1993 - August 1993	0.078	0.222	- 0.144
April 1994 - August 1994	0.073	0.231	- 0.158
Summer 1992 - 1994 Average	0.074	0.226	- 0.152

Note: Refinery production of low-RVP motor gasoline is assumed to begin one month before the product is required at distribution terminals.
Sources: Energy information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(95/02) (Washington, DC, February 1995), p. 38, and earlier issues.

estimated coefficients for dummy variables that represent the Summer RVP control seasons indicate that net refinery inputs of LPGs declined by 54,000 barrels per day during the Phase I RVP control season (refinery inputs of LPGs declined about 14,000 barrels per day and refinery production increased by 40,000 barrels per day). Net refinery inputs declined by an additional 52,000 barrels per day in phase II (refinery inputs increased by 6,000 barrels per day, while refinery outputs increased by an additional 58,000 barrels per day in Phase II over Phase I).[3]

It is not surprising that the observed reduction in net refinery inputs of LPGs is lower than the 144,000 barrels per day implied by the simple linear vapor pressure blend calculation noted above. Refining cost minimization should lead to vapor pressure reduction by other means, such as changes in secondary processing unit operating conditions (e.g., catalytic cracking or reforming units) and increasing production of low vapor pressure gasoline blendstocks.

Refinery motor gasoline yields from crude oil and other refinery inputs did not significantly increase during the summer months to make up for the LPGs displaced from the motor gasoline pool.

The removal of normal butane from the summer motor gasoline pool implies an equivalent reduction in the refinery output of motor gasoline for a given volume of refinery inputs, such as crude and unfinished oils. However, refiners may increase motor gasoline yields from a given feedslate to make up for the LPGs removed. Linear regression of refinery production of motor gasoline against net inputs of LPGs, along with refinery inputs of crude oil and other feedstocks, suggests motor gasoline production declines by 0.87 barrels for each barrel reduction in net refinery inputs of LPGs (Appendix A.3). Thus, it appears refiners made only small yield adjustments for the reduction in LPGs blended into motor gasoline during the summer.[4] This small response is likely due to the high marginal cost of increasing motor gasoline production in secondary refinery processing units, such as catalytic crackers, that are already run at very high rates and severities in the summer motor gasoline season.

Refinery inputs of crude oil increased by over 170,000 barrels per day during the Phase I RVP control season to make up for the lost motor gasoline volume. Crude oil inputs fell back during Phase II with the increase in oxygenate blending.

Another option refiners have for making up the lost motor gasoline production is to increase crude oil feed rates. Linear regression analysis of refinery inputs of crude oil (controlling for total domestic petroleum product demand and other refinery inputs) suggests that refinery crude oil feed rates increased by just over 1.1 barrels for each 1 barrel decline in net refinery inputs of LPGs (Appendix A4).[5] Given an estimated yield of 0.42 barrels of motor gasoline from 1 barrel of crude oil (Appendix A3), increased refinery crude runs produce about 0.46 barrels of gasoline for each 1 barrel decline in net refinery inputs of LPGs.

The increase in crude oil inputs under the RVP regulations contributed to the U.S. changing from a net importer of distillate fuel oil to a net exporter.

Coincident with the increase in crude oil runs under the RVP regulations was a dramatic shift in the domestic distillate fuel oil balance. The U.S. went from being a net *importer* of an average 209,000 barrels per day in 1989 to being a net *exporter* of an average 10,000 barrels per day by 1991.[6] The regression analysis cannot identify whether the increase in domestic refinery crude oil inputs and reduction in distillate fuel oil net imports was driven primarily by the reduction of LPGs in the motor gasoline pool or by an increase in foreign demand for distillate fuel oil, such as in the Far East.

The effect of RVP regulations on motor gasoline imports and inventories cannot be identified.

Two other primary sources of summer motor gasoline supply are imports and inventories. Net imports of motor gasoline have been on a steady decline since the start of the RVP regulations. This trend is consistent with the decline in distillate net imports. The impact of RVP regulations on motor gasoline net imports may not be separable from changes in the international petroleum balance.

Accumulation of finished motor gasoline inventories during the winter heating season may increase to make up for lower summer production under the RVP regulations. However, motor gasoline inventories at their peak (usually occurring during January or February) have generally been lower under the RVP regulations. These lower motor gasoline inventories may be a result of the increase in oxygenate stocks, particularly MTBE (methyl tertiary butyl ether), and the association between inventories and RVP regulations cannot be identified.

Normal butane prices were hit hard by the Phase I RVP regulations, but slowly recovered during Phase II.

The decline in normal butane demand for motor gasoline blending put downward pressure on butane prices. The price of normal butane relative to unleaded gasoline on the U.S. Gulf Coast fell about 5 cents per gallon between 1987 and 1988, one year before the start of the RVP Phase I regulations (Table 3). Most of the price decline in the butane market occurred during the second half of 1988. The weakness in the butane market was even more dramatic during 1989. While the price of motor gasoline during the Summer of 1989 was about 10 cents per gallon higher than the price during the previous summer, the price of normal butane was almost 4 cents per gallon lower. The oxygenated and reformulated gasoline programs have contributed to a recovery in butane prices because of butane demand for MTBE production. About 0.95 gallons of normal butane are required to produce 1 gallon of MTBE.[7] Domestic MTBE production has increased from 84 thousand barrels per day in 1990 to 142 thousand barrels per day in 1994.[8] Butane prices

Table 3. Price Relationships Between Normal Butane and Unleaded Gasoline
(Cents per Gallon)

	Summer Months			Winter Months		
	Gasoline	n-Butane	Price Ratio Butane-to-Gasoline	Gasoline	n-Butane	Price Ratio Butane-to-Gasoline
1986	42.48	28.55	0.67	44.18	31.88	0.72
1987	52.77	35.97	0.68	48.38	37.29	0.77
1988	50.61	30.15	0.60	45.13	29.20	0.65
1989	60.29	26.45	0.44	52.38	30.76	0.59
1990	67.27	32.81	0.49	73.07	49.47	0.68
1991	66.14	38.47	0.58	61.08	45.14	0.74
1992	61.37	38.61	0.63	54.71	39.14	0.72
1993	55.38	37.46	0.68	47.80	36.21	0.76
1994	52.17	33.93	0.65	44.88	35.90	0.80

Notes: Summer price is day-weighted average for April 1 through August 31. Winter price is day-weighted average for January through March and September through December. Gasoline price is U.S. Gulf Coast unleaded 87 octane waterborne spot price. Normal Butane price is Mont Belvieu spot price.

Source: McGraw-Hill, Inc., *Platt's Oilgram Price Report* (New York, NY), various issues.

Table 4. Market Price Premium for Low Vapor Pressure (RVP) Gasoline
(Cents per Gallon)

	U.S. Gulf Coast Waterborne Spot Price			Mont Belvieu
	9.0 RVP	7.8 RVP	Difference	Normal Butane
April 1993	58.90	59.76	0.86	40.14
May 1993	58.76	59.92	1.16	36.73
June 1993	54.07	54.69	0.62	37.43
July 1993	50.01	50.58	0.57	36.85
August 1993	51.34	52.06	0.72	36.26
Day-Weighted Average	54.59	55.38	0.79	37.46
April 1994	48.66	49.35	0.69	30.88
May 1994	48.99	49.57	0.58	34.33
June 1994	52.05	52.88	0.83	34.58
July 1994	53.76	54.56	0.80	35.06
August 1994	53.66	54.41	0.75	34.73
Day-Weighted Average	51.44	52.17	0.73	33.93

Source: McGraw-Hill, Inc., *Platt's Oilgram Price Report* (New York, NY). various issues.

over the last several years have recovered to their pre-1988 relationship with unleaded gasoline.

Motor gasoline prices increase by about 0.63 cents per gallon for each 1 psi reduction in Reid vapor pressure.

Lowering RVP increases the refiner's cost of producing gasoline because low-cost normal butane must be removed from the gasoline pool. Moreover, if refiners'marginal cost of producing gasoline is an increasing function of motor gasoline yields, then efforts to replace the lost butane volume through higher yields from other refinery inputs should also contribute to higher motor gasoline prices. The wholesale market price premium for 7.8 RVP gasoline relative to 9.0 RVP gasoline on the U.S. Gulf Coast during the summers of 1993 and 1994 (April through August) averaged 0.76 cents per gallon, which is equivalent to a price premium of about 0.63 cents per gallon per psi reduction (Table 4).

Motor vehicle fuel efficiency is expected to increase by as much as one-half percent because of the reduction in motor gasoline RVP.

A reduction in motor gasoline RVP should lead to improved automobile fuel efficiency (on a miles per gallon basis) and lower motor gasoline demand through an increase in motor gasoline energy density (Btu per gallon) and less fuel loss through evaporation.[9] A 2 percent reduction in the butane content of motor gasoline may increase energy density and fuel efficiency by as much as 0.43 percent.[10] However, estimating the improvement in fuel economy resulting from RVP reductions is problematic because the contribution from fuel quality changes cannot be separated from the general trend of improvement associated with lighter cars and more fuel efficient engines.

Oxygenated Gasoline Regulations

The oxygenated gasoline program, mandated by Title II of the Clean Air Act Amendments of 1990, became effective on November 1, 1992. About one-third of all motor gasoline sold during the winter must now contain at least 2.7 percent oxygen by weight in blended oxygenates.[11] Methyl tertiary butyl ether (MTBE) and fuel ethanol have been the oxygenates of choice in motor gasoline blending. The 2.7 percent by weight oxygen specification is equivalent to 15.2 percent MTBE or 7.6 percent fuel ethanol by volume.[12]

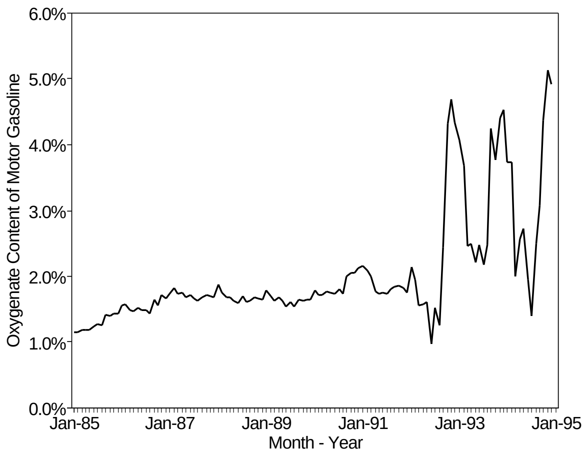
The increase in oxygenate blending into motor gasoline also impacts the supply, demand, and price of motor gasoline. The high blending rates of oxygenates during the winter increases the volume of motor gasoline product supplied relative to the volumes of other refined products. New supplies of oxygenates from sources other than crude oil (MTBE from natural gas and liquefied petroleum gases; and ethanol from corn) reduce the demand on refinery inputs of crude oil. Motor gasoline prices are higher because of the blending of higher cost oxygenates mandated by the regulations. Motor gasoline demand is also expected to increase because, in contrast to the RVP regulations, the energy content of oxygenated gasoline is lower than that of conventional gasoline.

Oxygenate (MTBE and fuel ethanol) blending into motor gasoline has almost doubled in the last 5 years under the oxygenated gasoline program.

MTBE and fuel ethanol usage has grown since the early 1980's in response to octane demand resulting initially from the phaseout of lead from gasoline and later from rising demand for premium gasoline. Federal and local tax incentives for blending renewable fuels into motor gasoline have contributed to the growth in demand for fuel ethanol.

The oxygenated gasoline program stimulated a dramatic increase in fuel ethanol and MTBE production between 1991 and 1994.[13] The volume of oxygenates blended into motor gasoline has increased along with capacity. Ethanol demand for motor gasoline blending has increased from an average 49 thousand barrels per day in 1990 to 83 thousand barrels per day in 1994. MTBE demand increased from 81 to 158 thousand barrels per day between 1990 and 1994. Oxygenate blending also has a very strong seasonal component because of the winter-only oxygenated gasoline program (Figure 1).

Figure 1. Oxygenate Content of Motor Gasoline
(percent by volume)



Sources: Details provided in Figure Reference section, p. 43.

Refinery production of motor gasoline increased by 1.4 barrels for each 1 barrel increase in oxygenate blending.

With an increase in refinery inputs of oxygenates, refinery output of motor gasoline may exhibit a larger or smaller increase (for a given volume of other refinery inputs). The change in refinery output of motor gasoline may be smaller than the change in refinery inputs of oxygenates because refiners may cut back on production of other high octane blend components, such as aromatics in secondary processing units (e.g., cat crackers and reformers). However, the reduction of aromatics production may increase motor gasoline yields in these units because the severity of the unit's operating conditions (e.g., temperature, pressure, and reactor space velocity) may be reduced. Linear regression analysis (Appendix A.3) indicates that refinery output of finished motor gasoline increased by 1.4 barrels for each 1 barrel increase in oxygenate blending.

Refinery inputs of crude oil declined by ½ barrel for each 1 barrel increase in oxygenate blending.

The increase in the supply of oxygenates derived from non-petroleum sources is expected to reduce demand for crude oil or product imports. However, the offset is likely to be less than 1-for-1. One barrel of MTBE is produced from 0.95 barrels of normal butane (or 0.79 barrels of isobutylene) and 0.34 barrels of methanol. Normal butane is recovered from either natural gas liquids or petroleum. Methanol is produced from natural gas. If the MTBE feedstocks are obtained from the natural gas market then either increased natural gas production is required or other hydrocarbons, most likely coming from crude oil, must be substituted. Linear regression analysis of refinery inputs of crude oil against other refinery inputs (Appendix A.4), total petroleum product demand and inventories, suggests that refinery crude runs declined by 0.53 barrels for each additional barrel of oxygenate blended into motor gasoline.

Comparison of current finished gasoline inventories to historical levels may be misleading if oxygenate stocks are not considered.

Analysis of motor gasoline inventories has traditionally focused on either finished motor gasoline stocks or finished motor gasoline plus gasoline blend component stocks. Gasoline inventories are usually at their highest during January or February of every year. Finished motor gasoline stocks at the end of January 1995 were at the lowest level recorded for any January in over 20 years, on either a volume or days supply basis (Table 5). Similar observations may be made for finished motor gasoline plus gasoline blend component stocks. The general conclusion has been that gasoline stocks were abnormally low going into 1995. However, this conventional analysis fails to include oxygenate stocks, which have grown dramatically since early 1992. In fact total gasoline inventory volumes, including oxygenates, have been much higher in the last three years than in most of the preceding 10 years. While total gasoline inventory on a days supply basis was low at the end of January 1995, it was only slightly lower than the levels observed between 1988 and 1992.

The price premium for oxygenated gasoline is about 3 to 4 cents per gallon over conventional gasoline.

Before the start of oxygenated gasoline program the price of MTBE and fuel ethanol were directly related to

Table 5. January Inventories of Motor Gasoline, Gasoline Blendstocks, and Oxygenates

January Year	Finished Motor Gasoline		Finished Motor Gasoline Plus Blendstocks		Finished Motor Gasoline Plus Blendstocks Plus Oxygenates	
	Volume	Days Supply	Volume	Days Supply	Volume	Days Supply
1995	**182.8**	**24.4**	227.1	**30.4**	243.0	**32.5**
1994	194.7	27.0	236.0	32.7	247.3	34.3
1993	197.8	28.1	239.6	34.0	255.0	36.2
1992	191.1	27.0	229.3	32.4	235.4	33.3
1991	185.6	27.1	**225.0**	32.8	227.0	33.1
1990	196.3	27.5	236.3	33.1	237.2	33.2
1989	205.7	28.8	248.6	34.8	249.2	34.8
1988	200.8	28.7	240.3	34.3	240.7	34.3
1987	210.6	31.4	251.1	37.4	251.5	37.5
1986	201.1	30.9	238.3	36.6	238.8	36.7
1985	198.4	30.5	233.7	35.9	234.1	36.0
1984	185.5	29.5	225.6	35.9	**225.9**	35.9

Notes: Volumes in millions of barrels.
Days Supply = January end-of-month inventory volume divided by first quarter average finished motor gasoline product supplied.
Lowest inventory in series highlighted in bold numbers.
Source: Energy Information Administration, *Petroleum Supply Annual 1994*, Volume 1, DOE/EIA-0340(94)/1 (Washington, DC, May 1995), pp. 17, 71-73, and earlier issues.

their value as blendstocks in conventional unleaded gasoline, based on their blend octane numbers and vapor pressures.[14] The oxygenated gasoline program mandating a minimum oxygen content drives a wedge between MTBE or ethanol prices and octane blend value since a substantial amount of these oxygenates have to be used regardless of octane demand.

The price premium for oxygenated gasoline during the first two winter control seasons ranged from 3 to 4 cents per gallon, with an MTBE price ranging from 60 to 80 cents per gallon (Table 6). When the price of MTBE increased to over $1.00 per gallon late in 1994, the price premium for oxygenated gasoline rose to over 6 cents per gallon. The MTBE price increase during the second-half of 1994 occurred not because of an increase demand for oxygenates but because of a rise in the price of the feedstock methanol, which more than doubled in price as a result of unexpected extended plant outages.[15]

Oxygenated gasoline contributes to a loss in automobile fuel efficiency of 2 to 3 percent.

Motor gasoline demand is expected to increase because of lower automobile fuel efficiency (on a miles per gallon basis) associated with the burning of lower energy-content oxygenates. The energy content of MTBE is about 93,500 Btu per gallon and the energy content of ethanol is 76,000 Btu per gallon, while that of conventional motor gasoline is about 114,000 Btu per gallon.[16] The Environmental Protection Agency combined the results of 19 independent studies with more than 4,000 vehicle/fuel tests and found that

Table 6. MTBE, Oxygenated, and Conventional Unleaded Motor Gasoline Price Relationship
(Cents per Gallon)

		N.Y. Harbor Cargo			U.S. Gulf Coast Waterborne			
		Conv.	Oxy.	Diff.	Conv.	Oxy.	Diff.	MTBE
Oct	1992	60.04	63.64	3.60	59.42	62.77	3.35	81.63
Nov		56.74	60.79	4.05	53.84	56.98	3.14	80.88
Dec		52.99	57.16	4.17	50.89	54.66	3.77	75.66
Jan	1993	53.07	56.97	3.90	51.83	55.11	3.28	71.69
Feb		52.74	56.53	3.79	51.46	54.38	2.92	
Average		*55.12*	*59.02*	*3.90*	*53.49*	*56.78*	*3.29*	*77.47*
Oct	1993	50.34	53.04	2.70	48.32	50.79	2.47	72.22
Nov		44.32	47.4	3.08	42.31	44.82	2.51	67.18
Dec		37.99	41.32	3.33	36.20	40.54	4.34	61.50
Jan	1994	42.44	44.96	2.52	41.90	45.44	3.54	61.04
Feb		44.06	46.88	2.82	43.84	46.79	2.95	60.15
Average		*43.83*	*46.72*	*2.89*	*42.51*	*45.68*	*3.16*	*64.42*
Oct	1994	50.92	59.61	8.69	48.61	55.52	6.91	106.95
Nov		51.15	57.34	6.19	46.19	52.86	6.67	107.85
Dec		46.64	52.70	6.06	43.11	50.95	7.84	98.65

Notes: Conv. - Conventional unleaded 87 octane motor gasoline
Oxy. - Oxygenated unleaded 87 octane motor gasoline
Diff. - Difference between conventional and unleaded prices
MTBE - U.S. Gulf Coast spot price

Source: McGraw-Hill, Inc., *Platt's Oilgram Price Report*, Price Average Supplement, December 1994, Vol. 73, No. 48 (New York, NY, March 10, 1995), pp. 2-3, and earlier issues.

fuel economy effects depend solely on fuel energy content and that oxygenated gasoline fuel economy is 2 to 3 percent lower than that for conventional gasoline.[17]

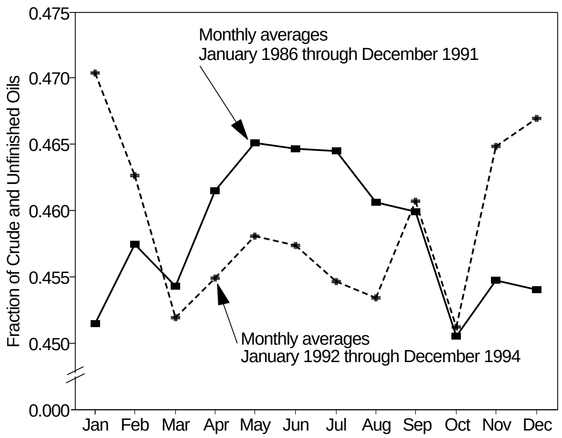
Cumulative Effects of Environmental Regulations

The environmental regulations have had a significant cumulative effect on petroleum refining operations. The RVP regulations have reduced summer motor gasoline production, and the oxygenated gasoline program has increased winter motor gasoline production. Consequently, refinery yields of motor gasoline have been significantly affected.

Refinery motor gasoline yields have shifted dramatically from a maximum during the spring to a high during the winter.

Petroleum refiners have traditionally increased motor gasoline production relative to distillate fuel production around March or April of every year, with the gasoline mode of production lasting about 6 months. This shift between gasoline and distillate production is a response to seasonal demand swings, where gasoline demand is highest during the summer driving season and distillate demand peaks during the winter heating season. The swing in demand for motor gasoline is about 1 million barrels per day from the low point in January to peak demand in July. The distillate fuel demand swing is about 0.7 million barrels per day from the usual July low to the high demand months of December through February.[18]

Figure 2. Average Refinery Yields of Motor Gasoline
(refinery gasoline output as fraction of crude and unfinished oil inputs)



Sources: Details provided in Figure Reference section, p.43.

The seasonal pattern of production should be smoother than the seasonal pattern of demand because of production cost smoothing whereby inventories are used to buffer expected demand swings. Because of refining (secondary processing) capacity constraints, excess motor gasoline is produced during the winter months, when the marginal cost of producing gasoline is low; it is retained in inventory and then drawn from inventory during the high demand summer months, when the marginal cost of gasoline production is high.

Seasonality in production is observed in the refinery yields of motor gasoline and distillate fuel (measured as either a fraction of refinery inputs or a fraction of total product output). Refinery yields of motor gasoline have historically been highest during the spring and summer and lowest during the winter. However, the refinery gasoline yield pattern since 1992 has dramatically reversed (Figure 2). Before 1992, gasoline yield typically increased from a low of about 45.1 percent of refinery inputs of crude and unfinished oils during January to a high of about 46.5 percent during May and June. Since 1992, motor gasoline yields fell from a January high of over 47 percent to 45.5 percent in June. A change in gasoline yield of 1 percent represents about 150,000 barrels per day change in gasoline production for an (annual) average level of total refinery output.

Notes: Chapter 2

[1] Internal calculation based on lowering 11.5 psia vapor pressure finished motor gasoline to 10.5 psia by removing 60 psia normal butane.

[2] Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340(91)/1 (Washington, DC, June 1992), p. 17.

[3] The estimated coefficients for the Phases I and II RVP dummy variables in the LPG refinery input equation are small and not statistically significant at the 90 percent confidence level.

[4] Dummy variables representing the Phase I and Phase II RVP control seasons were also included. After controlling for net refinery inputs of LPGs, the estimated regression coefficients on the RVP dummy variables were not statistically significant. The RVP dummy variables are omitted from the *Short-Term Integrated Forecasting System* model that generates forecasts for the *Short-Term Energy Outlook*.

[5] The estimated coefficients on the RVP season dummy variables are not statistically significant and are omitted from the *Short-Term Energy Integrated Forecasting System* model.

[6] Energy Information Administration, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93)/1 (Washington, DC, June 1994), p. 19.

[7] National Petroleum Council, *U.S. Petroleum Refining*, Volume 1 (Washington, DC, August 1993) p. 148.

[8] 1994 MTBE production from Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(95/01), (Washington, DC, January 1995), p. 137. MTBE production for 1990 provided by DeWitt & Company, Houston, Texas. It should be noted that increased MTBE production *within* refineries can actually reduce butane demand. Isobutylene that is normally reacted with isobutane to form alkylate may instead be reacted with methanol to produce MTBE, thus reducing isobutane demand in alkylation plants. However, much of the new MTBE capacity built since 1990 obtains the isobutylene feedstock from normal butane isomerization/dehydrogenation.

[9] Higher motor gasoline price will also lead to slightly lower demand. The Short-Term price elasticity of demand is about -0.11, so that 1-percent increase in the price of motor gasoline will lead to a 0.11 percent reduction in demand ("Demand, supply and Price Outlook for reformulated gasoline, 1995, "Short-Term Energy Outlook Annual Supplement 1994, DOE/EIA-0202(94) Washington, DC, August 1994, p.8.)

[10] Based on a simple linear calculation assuming a reduction of normal butane (93,201 Btu per gallon lower heating value) from 5 to 3 volume percent in conventional gasoline (114,000 Btu per gallon lower heating value before butane removal assumed).

[11] For reviews of the oxygenated gasoline program requirements and oxygenate supply and demand issues refer to Energy Information Administration, "Demand, Supply, and Price Outlook for Oxygenated Gasoline," *Short-Term Energy Outlook Annual Supplement 1992*, DOE/EIA-0202(92) (Washington, DC, June 1992), pp. 3-10, and "The Economics of the Clean Air Act Amendments of 1990: Review of the 1992-1993 Oxygenated Motor Gasoline Season," *Monthly Energy Review*, DOE/EIA-0380(94/05) (Washington, DC, August 1993).

[12] These percentages may change by as much as ± 0.5 percent absolute (i.e., MTBE in oxygenated gasoline may range from 14.7 to 15.7 volume percent) depending on the density of motor gasoline, the purity of the oxygenate, and the assumed average oxygen content.

[13] Refer to Chapter 5, "Oxygenate Supply/Demand Balances in the Short-Term Integrated Forecasting Mode," in this report.

[14] Cambridge Energy Research Associates reported that an estimated 30 to 60 percent of ethanol production had been blended into finished motor gasoline so that the blend will qualify for Federal (and State) tax credits. In these applications ethanol is described as a gasoline "extender" rather than a source of octane. (*The U.S. Refining Industry: Facing Challenges of the 1990's*, January 1992).

[15] Energy Information Administration, *The Energy Information Administration's Assessment of Reformulated Gasoline: An Update*, SR/OOG/94-03 (Washington, DC, December 1994), pp. 14-16.

[16] Energy Information Administration, "Demand, Supply, and Price Outlook for Oxygenated Gasoline," *Short-Term Energy Outlook Annual Supplement*, DOE/EIA-0202(92) (Washington, DC, June 1992), p. 6.

[17] Environmental Protection Agency, "On-Road Study of the Effects of Reformulated Gasoline on Motor Vehicle Fuel Economy in Southeastern Wisconsin," (Washington, DC, March 31, 1994), p. 4.

[18] Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340(93)/1 (Washington, DC, June 1994), pp. 17 and 19.

3. Comparison of EIA and Other Forecasts for 1995 and 1996

This chapter compares EIA's energy forecasts for 1995 and 1996 as published in the second quarter 1995 *Short-Term Energy Outlook* with forecasts of several other major U.S. energy forecasters.[19] These forecasts are: DRI/McGraw-Hill (DRI), Wharton Economic Forecasting Associates (WEFA), National Economic Research Associates (NERA), and the Independent Petroleum Association of America (IPAA).[20] The forecasts were chosen on the basis of the forecast years covered as well as the inclusiveness of the data. However, not all of the forecasts provide projections for all of the series in the tables. In addition, the IPAA forecast extends only through 1995. Tables 7 and 8 summarize these projections. This comparison focuses on the similarities and differences in the forecasts with regard to macroeconomic and price assumptions as well as supply and demand projections.

In the following discussion, as well as in Table 7, the 1994-1995 changes (in both percentage and absolute terms) are based on the 1994 estimates for the data series provided by each forecaster. Because of the different timing of the forecasts, these estimates may differ from those of EIA. The forecasters often did not have the most current historical EIA data for 1994 at the time of their forecasts. A summary of the 1994 historical data estimates for each forecaster is provided in Table 9.

Summary

All the forecasts were in general agreement on overall economic and energy growth trends for 1995 and 1996, except for differences in the timing and magnitude of the moderation of economic growth from the robust pace of 1994. In the projections extending through 1996, economic growth in terms of real gross domestic product (GDP) would slow from 4.0-percent in 1994 to approximately 2-3 percent in 1995 and 1996. All of the projections assumed continued low rates of inflation throughout the forecast interval with only a slight uptick in 1996. Projections for total energy demand were generally consistent with each other but exhibited more variation than those of general economic growth. In all of the projections, however, total energy growth was less than that of real GDP, resulting in continuing declines in energy intensity consistent with long-term trends. Even differences in projected oil price projections pointed towards a consensus of steady increases in prices, a pattern mirrored by the narrow range of increases in oil product prices. The projections, however, displayed greater diversity in natural gas prices, which appeared to exhibit little connection with oil prices from one year to the next. In 1995, natural gas prices were projected to decline in all but one of the projections before recovering in 1996. That divergence resulted in differences in relative prices of oil and natural gas and, hence, petroleum and natural gas demand patterns. Utility coal price forecasts called for little change during the forecast interval.

None of the projected increases in oil prices in any of the projections was sufficient to stem the continued declines in crude oil production projected in both 1995 and 1996. But all of the forecasts projected increases in total petroleum products demand. Differences in the price of oil relative to gas, as well as the timing of the release of the forecasts, appeared to account for the bulk of the difference in these projections. For 1995, natural gas production was slated to increase in the EIA, DRI and WEFA forecasts; IPAA and NERA forecasted declines. All of the forecasts, however, projected increases in natural gas production in 1996. Gas demand was projected to rise in all of the forecasts during the forecast interval, but at different rates, due to differences in relative prices of oil and gas and economic growth rates. Coal production and demand were forecasted to increase in each year. Coal demand in the DRI forecast is projected to increase only slightly in 1995 based on assumptions of increased nuclear and hydroelectric power generation.

Table 7. Comparison Summary—1995

Assumptions and Projections (publication date)	History 1994[a]	1995 Projections EIA 5/95	DRI 11/94	NERA 4/95	WEFA 5/95	IPAA 5/95
Price Assumptions (nominal)						
World Oil Price (dollars per barrel)	15.51	16.81	17.43	17.00	17.20	N/A
Petroleum Products (dollars per U.S. gallon)						
Motor Gasoline (retail)	1.17	1.23	1.26	1.24	1.23	N/A
Heating Oil (retail)	0.88	0.90	1.06	0.97	0.91	N/A
Natural Gas Wellhead (dollars per thousand cubic feet)	1.82	1.75	2.12	1.66	1.47	N/A
Coal—utility (dollars per million Btu)	1.36	1.36	1.33	N/A	1.41	N/A
Macroeconomic Indicators						
Real GDP (percentage change from previous year)	4.0	2.9	2.2	3.2	3.0	2.9
Industrial Index (percentage change from previous year)	5.4	5.2	2.4	4.8	4.4	4.0
Inflation (percentage change from previous year)	2.1	2.3	2.4	2.5	2.1	2.5
Personal Income (percentage change from previous year)	3.5	3.4	2.7	N/A	4.9	N/A
Energy Intensity[b]	16.64	16.44	15.97	N/A	N/A	16.08
(percent change from prior year)	-1.7	-1.2	-0.9	N/A	N/A	-2.2
Energy Supply						
Crude Oil Production (million barrels per day)[c]	6.63	6.46	6.61	6.56	6.51	6.47
Net Oil Imports (million barrels per day)[d]	7.99	8.28	8.37	8.63	8.33	8.59
Total Gas Production (trillion cubic feet)	18.85	18.95	18.83	18.55	18.50	18.75
Net Gas Imports (trillion cubic feet)	2.38	2.51	2.36	2.22	2.45	2.45
Coal Production (million short tons)	1,030	1,041	1,030	N/A	N/A	N/A
Net Coal Exports (million short tons)	64	69	79	N/A	N/A	N/A
Electricity Generation (billion kilowatthours)	2,911	2,959	2,918	2,990	2,946	N/A
Energy Demand						
Total Oil Products (million barrels per day)	17.68	17.79	17.93	17.83	17.91	17.83
(percent change from prior year)	2.6	0.6	1.3	0.8	1.4	0.9
Motor Gasoline (million barrels per day)	7.59	7.73	7.78	7.73	N/A	7.70
(percent change from prior year)	1.7	1.8	2.1	1.8	N/A	1.4
Jet Fuel (million barrels per day)	1.53	1.59	1.56	1.58	N/A	1.56
(percent change from prior year)	3.9	3.9	2.8	3.3	N/A	1.7
Distillate (million barrels per day)	3.17	3.17	3.25	3.15	N/A	3.23
(percent change from prior year)	4.1	0.0	2.1	-0.6	N/A	1.5
Residual (million barrels per day)	1.00	0.96	1.02	0.90	N/A	0.90
(percent change from prior year)	-7.2	-4.0	-5.6	-10.0	N/A	-8.8
Natural Gas Demand (trillion cubic feet)	20.60	21.30	20.96	20.58	N/A	20.54
(percent change from prior year)	1.5	3.4	1.5	-0.1	N/A	0.7
Coal Demand (million short tons)	937	954	938	N/A	N/A	N/A
(percent change from prior year)	0.6	1.8	0.5	N/A	N/A	N/A
Electricity Sales (billion kilowatthours)	2,928	2,989	2,886	3,020	3.006	N/A
(percent change from prior year)	2.3	2.1	1.5	2.7	2.7	N/A
Total Energy Demand (quadrillion Btu)	85.3	86.8	86.8	N/A	85.5	86.0
(percent change from prior year)	1.8	1.7	1.3	N/A	1.8	0.7
Net Oil Import Dependence (percent)	45.2	47.8	46.7	46.1	46.5	48.2

[a]EIA data.
[b]Primary energy use per dollar GDP, in thousand Btu per 1987 dollars.
[c]Excludes NGL's.
[d]Crude oil and products.
Btu = British Thermal Unit.
N/A = Not available.

Sources: U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook*, Second Quarter, 1995; DRI/McGraw-Hill, *Energy Review*, Fall-Winter 1994-95; National Economic Research Associates, *Energy Outlook*, April 1995; The WEFA Group, *Energy Outlook*, May 1995; Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Term Forecast, 1993-2010*, May 1995.

NOTE: Percentage Change Calculations are Based on 1994 Historical Estimates of Each Forecaster, Which May Differ from Those of EIA.

Table 8. Comparison Summary—1996

Assumptions and Projections (publication date)	History 1994[a]	1996 Projections EIA 5/95	DRI 11/94	NERA 4/95	WEFA 5/95
Price Assumptions (nominal)					
World Oil Price (dollars per barrel)	15.51	17.26	18.25	18.00	17.67
Petroleum Products (dollars per U.S. gallon)					
Motor Gasoline (retail)	1.17	1.27	1.31	1.29	1.26
Heating Oil (retail)	0.88	0.98	1.11	1.01	.95
Natural Gas Wellhead (dollars per thousand cubic feet)	1.82	1.95	2.20	2.00	1.62
Coal—utility (dollars per million Btu)	1.36	1.38	1.30	N/A	1.44
Macroeconomic Indicators					
Real GDP (percentage change from previous year)	4.0	1.9	2.5	2.2	2.3
Industrial Index (percentage change from previous year)	5.4	1.3	2.1	2.8	2.5
Inflation (percentage change from previous year)	2.1	2.4	2.5	3.0	2.8
Personal Income (percentage change from previous year)	3.5	2.3	2.7	N/A	4.4
Energy Intensity[b]	16.64	16.49	15.82	N/A	N/A
(percent change from prior year)	-1.7	0.3	-1.0	N/A	N/A
Energy Supply					
Crude Oil Production (million barrels per day)[c]	6.63	6.24	6.47	6.36	6.42
Net Oil Imports (million barrels per day)[d]	7.99	8.91	8.81	8.92	8.56
Total Gas Production (trillion cubic feet)	18.85	19.08	19.24	18.80	18.70
Net Gas Imports (trillion cubic feet)	2.38	2.75	2.40	2.32	2.49
Coal Production (million short tons)	1,030	1,058	1,009	N/A	N/A
Net Coal Exports (million short tons)	64	75	82	N/A	N/A
Electricity Generation (billion kilowatthours)	2,911	3,036	2,952	3,040	3,009
Energy Demand					
Total Oil Products (million barrels per day)	17.68	18.25	18.22	18.08	18.10
(percent change from prior year)	2.6	2.6	1.6	1.4	1.1
Motor Gasoline (million barrels per day)	7.59	7.84	7.93	7.80	N/A
(percent change from prior year)	1.6	1.4	1.9	0.9	N/A
Jet Fuel (million barrels per day)	1.53	1.62	1.60	1.62	N/A
(percent change from prior year)	3.9	2.5	2.1	2.5	N/A
Distillate (million barrels per day)	3.17	3.24	3.31	3.15	N/A
(percent change from prior year)	4.3	2.1	1.8	0.0	N/A
Residual (million barrels per day)	1.00	1.09	1.02	0.95	N/A
(percent change from prior year)	-7.2	13.5	-0.1	5.6	N/A
Natural Gas Demand (trillion cubic feet)	20.60	21.52	21.28	20.90	N/A
(percent change from prior year)	1.5	1.0	1.5	1.6	N/A
Coal Demand (million short tons)	937	977	939	N/A	1,011
(percent change from prior year)	0.6	2.4	0.1	N/A	3.6
Electricity Sales (billion kilowatthours)	2,928	3,078	2,924	3,090	3,106
(percent change from prior year)	2.3	3.0	1.3	2.4	3.3
Total Energy Demand (quadrillion Btu)	85.3	88.7	88.1	N/A	87.2
(percent change from prior year)	1.8	2.3	1.5	N/A	2.0
Net Oil Import Dependence (percent)	45.2	48.8	48.4	49.2	47.3

[a]EIA data (preliminary).
[b]Primary energy use per dollar GDP, in thousand Btu per 1987 dollars.
[c]Excludes NGL's.
[d]Crude oil and products.
Btu = British Thermal Unit.
N/A = Not available.
Sources: U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook*, Second Quarter, 1995; DRI/McGraw-Hill, *Energy Review*, Spring-Summer 1995; National Economic Research Associates, *Energy Outlook*, April 1995; Independent Petroleum Association of America.

Table 9. Historical Data Comparison—1994

Forecaster Publication Date	EIA 5/95	DRI 11/94	NERA 4/95	WEFA 5/95	IPAA 5/95
Price Assumptions (nominal)					
World Oil Price (dollars per barrel)	15.51	15.86	15.59	15.53	N/A
Petroleum Products (dollars per U.S. gallon)					
Motor Gasoline (retail)	1.17	1.19	1.17	1.17	N/A
Heating Oil (retail)	0.88	1.00	0.88	.86	N/A
Natural Gas Wellhead (dollars per thousand cubic feet)	1.82	2.01	1.80	1.76	N/A
Coal—utility (dollars per million Btu)	1.36	1.37	N/A	1.38	N/A
Macroeconomic Indicators					
Real GDP (percentage change from previous year)	4.0	3.6	4.0	4.1	4.0
Industrial Index (percentage change from previous year)	5.4	5.2	5.4	5.3	5.4
Inflation (percentage change from previous year)	2.1	2.1	2.1	2.1	2.1
Personal Income (percentage change from previous year)	3.5	3.1	N/A	N/A	N/A
Energy Intensity[a]	16.64	16.11	N/A	N/A	16.64
Energy Supply					
Crude Oil Production (million barrels per day)[b]	6.63	6.72	6.63	6.64	6.63
Net Oil Imports (million barrels per day)[c]	7.99	8.03	7.98	7.99	7.99
Total Gas Production (trillion cubic feet)	18.85	18.64	18.85	18.10	18.85
Net Gas Imports (trillion cubic feet)	2.38	2.42	2.37	2.40	2.38
Coal Production (million short tons)	1,030	1,019	N/A	N/A	N/A
Net Coal Exports (million short tons)	64	66	N/A	N/A	N/A
Electricity Generation (billion kilowatthours)	2,911	2,886	2,930	2,900	N/A
Energy Demand					
Total Oil Products (million barrels per day)	17.68	17.71	17.68	17.66	17.68
Motor Gasoline (million barrels per day)	7.59	7.63	7.59	N/A	7.59
Jet Fuel (million barrels per day)	1.53	1.52	1.53	N/A	1.53
Distillate (million barrels per day)	3.17	3.19	3.17	N/A	3.17
Residual (million barrels per day)	1.00	1.08	1.00	N/A	1.00
Natural Gas Demand (trillion cubic feet)	20.60	20.65	20.60	N/A	20.60
Coal Demand (million short tons)	937	934	N/A	N/A	N/A
Electricity Sales (billion kilowatthours)	2,928	2,844	2,940	2,928	2,928
Total Energy Demand (quadrillion Btu)	85.3	85.7	N/A	84.0	85.3
Net Oil Import Dependence (percent)	45.2	45.4	45.2	45.2	45.2

[a]Primary energy use per dollar GDP, in thousand Btu per 1987 dollars.
[b]Excludes NGL's.
[c]Crude oil and products.
Btu = British Thermal Unit.
N/A = Not available.
Sources: U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook*, Second Quarter, 1995; DRI/McGraw-Hill, *Energy Review*, Fall-Winter 1994-95; National Economic Research Associates, *Energy Outlook*, April 1995; Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Term Forecast, 1993-2010*, March 1995.

Economic and Price Assumptions

Real gross domestic product (GDP) grew by an estimated 4.1 percent in 1994. The projections assume slower economic growth in 1995, ranging from 2.2 percent (DRI) to 3.2 percent (NERA). EIA's projected growth rate for 1995 is 2.9 percent. In 1996, growth in all of the forecasts is projected to slow even further. These growth rates range from 1.9 percent (EIA) to 2.5 percent (DRI). In all of the forecasts, industrial production growth in 1995 is projected to outpace that of the overall economy, ranging from 2.4 percent (DRI) to 5.2 percent (EIA). In 1996, rates of growth of industrial output range from 1.3 percent (EIA) to 2.8 percent (NERA), reflecting divergences in cyclical patterns found in overall economic growth. Inflation projections for 1995, as expressed by the implicit price deflator, fall within a narrow range from 2.1 percent (WEFA) to 2.5 percent (NERA and IPAA). EIA's projection of 2.3 percent falls within the midpoint of that range. All of the projections call for a slight rise in inflation rates for 1996, ranging from 2.4 percent (EIA) to 3.0 percent (NERA).

Projections of world oil prices--and, hence, most oil product prices--reflect a consensus among the major forecasters with regard to both levels and year-to-year changes. For 1995, average crude oil price projections range from $16.81 per barrel (EIA)-—an increase of $1.31 from the 1994 average-—to $17.43 per barrel (DRI), an increase of $1.57. (It should be noted that recent hikes in oil prices may not be completely reflected in these projections). For 1996, year-to-year increases in crude oil prices range from $0.45 per barrel (EIA) to $1.00 per barrel (NERA). As a result, EIA's world oil price projection for that year remains the lowest of all the forecasts at $17.26 per barrel. At $18.25 per barrel, DRI's projection is the highest.

The narrow range of projected movements in product price projections reflect those of the underlying crude oil costs. For 1995, increases in retail motor gasoline prices were confined to within 6 cents per gallon (EIA and WEFA) and increase of 7 cents per gallon (DRI and NERA). All of the forecasts providing price projections for 1996 call for similar hikes in motor gasoline prices, ranging from 3 cents per gallon (WEFA) to 5 cents per gallon (DRI and NERA), reflecting the narrow range of crude oil price increases. Retail heating oil price hikes in 1995 are projected to range from 2 cents per gallon (EIA) to 9 cents per gallon (DRI). In 1996, heating oil prices are projected to increase in all of the forecasts by similar magnitudes--from 4 cents per gallon (NERA and WEFA) to 8 cents per gallon (EIA).

Natural gas wellhead price changes, which are only loosely related to crude oil price changes, displayed significant variation in 1995, ranging from an decline of 29 cents per thousand cubic feet (WEFA) to an increase of 11 cents per thousand cubic feet (DRI). EIA projected a decline of 7 cents. In 1996, natural gas prices are projected to increase in all the forecasts, with a range of 8 cents per million cubic feet (DRI) to 34 cents per million cubic feet (NERA) despite increases in crude oil costs of a similar magnitude between forecasts. EIA projected an increase of 20 cents per thousand cubic feet.

Primary Energy Supply

U.S. crude oil production is projected to continue to decline in 1995 in all of the available projections. The decline rates for that year range from 70,000 barrels per day (NERA) to 170,000 barrels per day (EIA). For 1996, declines in production rates from that of the previous year range 90,000 barrels per day (WEFA) to 220,000 barrels per day (EIA).

In all of the forecasts, continuing economic growth and declines in domestic production rates in 1995 result in increases in net imports of petroleum. Levels of net imports ranged from 8.28 million barrels per day (EIA)—an increase of 290,000 barrels per day—to 8.63 million barrels per day (NERA), an increase of 650,000 barrels per day. EIA projected net imports to be 8.28 million barrels per day, an increase of 290,000 barrels per day. For 1996, net imports are projected to range from 8.56 million barrels per day (WEFA) to 8.92 million barrels per day (NERA). EIA's projection was 8.91 million barrels per day. NERA's projection of a substantial increase in imports despite the larger-than-consensus increase in production results from strong growth in demand brought about by higher-than-consensus economic growth for that year.

In contrast to oil production, natural gas production patterns for 1995 show little consensus. They range from declines of 0.10 trillion cubic feet (tcf) (IPAA) to an increase of 0.40 tcf (WEFA). All of the forecasts project increases in natural gas production in 1996, ranging from 0.13 tcf (EIA) to 0.41 tcf (DRI). Differences in the price of natural gas accounted for the bulk of the divergences in production between forecasts. For 1996, EIA's projected price is $1.95 per thousand cubic feet; DRI's is $2.20.

Available forecasts for coal production (EIA and DRI) show increases in production for 1995 brought about by corresponding increases in demand. For 1996, however, DRI's projection calls for a decline in coal output, reflecting stagnant demand. EIA, however, projects continued, steady projected increases in coal production in line with consumption.

Energy Demand

Each of the forecasts projects growth in overall energy demand for the forecast interval, but at a rate less than that of the underlying economy, resulting in a continued decline in energy intensity. But projections for the various energy sources were found to be sensitive to differences in relative prices, economic growth rates, and timing of forecast publication.

Total petroleum demand for 1995 was projected to increase in all the forecasts, with growth ranging from 110,000 barrels per day (EIA) to 220,000 barrels per day (DRI). (WEFA projected growth of 250,000 barrels per day, but a breakdown by product was unavailable at the time of publication). The range of forecasted increases in 1995 motor gasoline consumption was between 110,000 barrels per day (IPAA) and 150,000 per day (DRI). EIA's projection was 140,000 barrels per day. The similarity of forecasts therefore does little to explain the overall divergence in total petroleum products demand. EIA's low growth rate stems primarily from the absence of growth in distillate demand (due to weather effects), which is an assumption of robust growth in natural gas consumption. DRI's higher growth derives in part from substantial (60,000 barrels per day) growth in distillate consumption. That projection, however, stems from the release of that forecast in late fall of 1994, which presumed normal weather patterns for the winter of 1994-1995. Moreover, EIA projected a 50,000 barrels per day decline in other oils demand for 1995. NERA's total petroleum demand projection for 1995 was similar to that of EIA but the composition of that growth was different. That forecast projected a 20,000 decline in distillate demand--the only such decline for that fuel--and a 100,000 barrels-per-day drop in residual fuel oil demand, the largest of the year-to-year declines.

Growth is projected in 1996 for petroleum demand in all of the forecasts, but with a wide variation. WEFA projects increases of 190,000 barrels per day; the EIA projects a 460,000 barrels-per-day increase in petroleum demand. Part of the robust increase in EIA's demand projections stems from displacement of natural gas by the robust residual fuel oil market brought about by changes in relative prices. Other forecasters project flat or declining growth in that market. But the growth EIA's 1996 distillate demand, which helped boost total demand growth, also reflects a recovery from depressed demand projected for 1995.

Natural gas demand patterns in 1995 partly reflect its competitive nature with oil. Growth projections for natural gas range from a decline of 0.02 tcf (NERA) to an increase of 0.70 tcf (EIA). EIA's projection is partly related to the low growth rate in petroleum demand, reflecting model assumptions about relative price sensitivities. But the slight decline in NERA's projection, whose oil demand projection for 1995 is similar to that of EIA, apparently reflects aggressive assumptions about fuel efficiency gains. In 1996, natural gas demand increases range from 0.22 tcf (EIA) to 0.52 tcf (NERA and DRI). The small increase in EIA's projection partly reflects the resumption of substantial oil demand growth brought about by price-induced fuel substitution.

Much of the difference in coal demand projections can be traced to divergences in assumptions about the change in the mix of power generation as well as different assumptions about electricity consumption growth. The low (0.5-percent) increase in DRI's 1995 coal demand stems from the combined effects of sluggish (1.1-percent) electricity demand growth and substantial growth in nuclear and hydroelectric generation capacity. At the other end of the spectrum, WEFA projects a 3.6-percent increase in coal demand as a result of 3.3-percent growth in electricity demand. EIA projects a 2.4-percent jump in coal demand, largely driven largely by a 3.0-percent hike in electricity demand.

Notes: Chapter 3

[19]U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202 (95/2Q).

[20]DRI/McGraw-Hill, *Energy Review* (Fall-Winter, October 1994); National Economic Research Associates, *Energy Outlook* (April 1995); Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Term Forecast, 1993-2010* (March 1995), Warton Economic Forecasting Associates (WEFA), May 1995.

4. Forecast Evaluation

This chapter evaluates errors between published forecast values and subsequent historical values for selected major energy variables: energy prices, macroeconomic variables, weather, demand, and production of petroleum, natural gas, coal, and electricity as published in the third quarter 1993 through the fourth quarter 1994 issues of the *Short-Term Energy Outlook (Outlook)*.[21] Detailed forecast error tables for selected variables are presented in Appendix B. This chapter continues a long tradition (since 1981) of presenting a discussion of average quarterly *Outlook* forecast errors. Also included are figures that show the percent error of one-year-ahead forecasts from 1986 through 1994 for six categories: refiner acquisition cost for crude oil, residential electricity prices, total petroleum demand, natural gas demand, domestic coal production, and electricity sales. These figures allow an historical examination of the "track record" and trends over the last 9 years of *Outlooks* (36 issues) of the forecasts for some of the key variables. These figures show that for these variables, the one-year-ahead forecasts have generally been improving in recent years.

Summary Error Analysis

Table 10 presents a summary of the average absolute errors for the forecasts published in the third quarter 1993 through the fourth quarter 1994 issues of the *Outlook*, as well as the average absolute errors published in the previous issue of the *Supplement* (covering the third quarter 1992 through the fourth quarter 1993 issues of the *Outlook*). Table 10 shows that 19 out of 34 of the forecasts improved, 2 were equal to, and 13 were worse compared to the forecast errors examined in the 1994 *Supplement*. Five of the seven selected price variables improved, including crude oil, all of the petroleum products, and residential electricity. However, three of the price forecasts worsened. The continued decline of natural gas wellhead prices and coal prices led to overstatements for these fuels and as well as residential natural gas prices. There were improvements for total petroleum demand, motor gasoline demand, distillate fuel oil demand, jet fuel demand, "other" petroleum products demand, total domestic crude oil production and Alaskan crude oil production.

There were also forecast improvements for industrial and commercial electricity sales and for electricity generation by natural gas. Over the last six issues of the *Outlook*, the forecasts for electricity prices, motor gasoline demand, total crude oil production, and industrial electricity sales had the smallest errors; residual fuel oil prices, residual fuel oil demand, natural gas wellhead prices, petroleum and hydroelectric generation had the largest errors.

The forecast evaluation tables (Tables B1 through B36) present the average absolute percent error of 21 quarterly forecasts made in six *Outlooks*, from the third quarter 1993 through the fourth quarter 1994. These forecast evaluation tables present the average absolute errors in physical units in the upper half of the table, and percent errors in the lower half. For Tables B1 through B36, the average absolute error *by quarter* (the last row on the bottom of each portion of the table) is calculated from top to bottom, by taking the mean of the absolute values of the differences between the actual and forecasted values for each quarter of the report. The average absolute error *by report* (the last column on the right-hand-side) is calculated horizontally across the table, by taking the mean of the absolute values of the differences between the actual value and the forecasted values for each quarter across reports. The overall error (shown in the bottom right-hand corner in both the upper portion (physical units) and lower portion (percent) for each table) is the mean of all of the absolute errors in the table.

Prices

Refiner Acquisition Cost of Imported Crude Oil

Prices, particularly the refiner acquisition cost (RAC) of imported crude oil, are important driving forces for many of the forecasts published in the *Outlook*. Errors

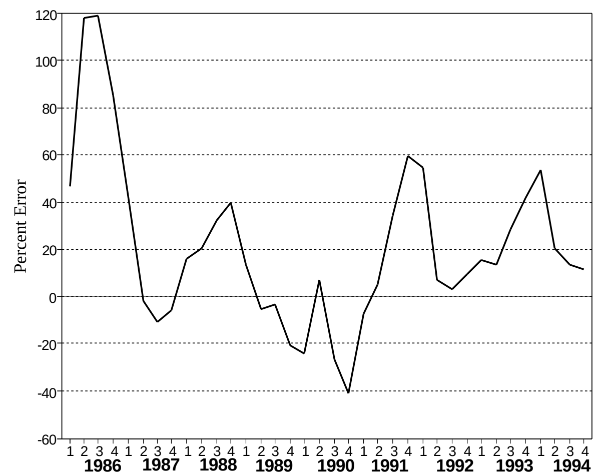
Table 10. Summary of Absolute Errors, *1995 Annual Supplement* Compared to *1994 Annual Supplement*

Variable	Average Absolute Percent Error: 6 Quarters 3Q93-4Q94 **1995 *Supplement***	Average Absolute Percent Error: 6 Quarters 3Q92-4Q93 **1994 *Supplement***
Oil Price and Macroeconomic Projections		
Refiner Acquisition Cost of Imported Crude Oil	13.8	20.3
Real Personal Disposable Income	0.9	1.4
Industrial Production Index, Manufacturing	1.8	2.1
Prices		
Motor Gasoline	3.7	5.8
Residential Heating Oil	7.4	8.7
Residual Fuel Oil	12.3	14.0
Residential Electricity	0.9	1.0
Wellhead Natural Gas	21.8	11.0
Residential Natural Gas	2.8	2.7
Electric Utility Coal	4.3	3.3
Petroleum		
Total Petroleum Demand	1.0	1.4
Motor Gasoline Demand	0.8	1.1
Distillate Fuel Oil Demand	2.5	2.8
Residual Fuel Oil Demand	14.9	7.3
Jet Fuel Demand	2.2	3.8
Other Petroleum Products Demand	2.8	3.1
Total Domestic Crude Oil Supply	1.0	1.3
Alaska Crude Oil Production	2.4	2.8
Lower 48 Crude Oil Production	0.8	1.4
Net Oil Imports	4.2	2.4
Total Petroleum Stocks	1.7	1.5
Natural Gas		
Natural Gas Demand	3.2	3.7
Natural Gas Production	2.3	2.2
Coal		
Domestic Coal Demand	3.2	2.3
Coal Production	2.6	7.8
Electricity		
Total Electricity Sales	1.9	1.9
Residential Electricity Sales	4.0	4.1
Commercial Electricity Sales	1.9	1.9
Industrial Electricity Sales	0.7	1.7
Generation by Fuel		
Coal	3.8	2.9
Petroleum	37.9	20.3
Natural Gas	6.4	11.5
Nuclear Power	4.8	4.2
Hydroelectric Power	11.4	10.9

in forecasting the RAC, while obviously having an adverse effect on the results for petroleum product prices, also affect to a lesser degree, the results of natural gas prices, as well as petroleum and natural gas demand and production. Based on the mid-oil price case forecasts, the overall average absolute error for the imported RAC was 13.8 percent or about $2.00 per barrel, over the last six issues of the *Outlook.* This compares with a previously reported error of 20.3 percent in the 1994 *Supplement* (Tables 10 and B1). Price projections in the last two quarters of 1993 and the first quarter of 1994 were overstated, not anticipating the falling price of the imported RAC. The principal reasons for the decline in the RAC were higher than expected production from the U.S and the North Sea, and the slower than anticipated economic growth in Japan and Western Europe.

Projecting imported crude oil prices over the relatively near-term period, such as one year into the future, has often proven to be a difficult task. This is because sudden and large price swings can occur due to unexpected geopolitical and economic events like the collapse of the OPEC price agreements in 1986 and the Persian Gulf War. Furthermore, it is hard to squarely pin down turning points for economic trends such as the economic recovery (or recession) in Western Europe and Japan. As a result, the RAC forecast errors for a particular quarter often have been substantial. Examining forecasts for one year ahead (four quarters ahead) for the periods for 1986 through 1994, shows a wide range of errors. For example, crude prices were overstated by 117 per cent (more than $15 per barrel) for the forecast made in the second quarter of 1985 for the second quarter of 1986. They were understated by more than 40 percent (about $12 per barrel) in the fourth quarter 1990 (Figure 3). Since there is so much uncertainty regarding world oil price forecasts, the *Outlook* has three price scenarios (side cases): low, mid, and high to cover the broad range of expectations. In half of the quarters evaluated here (18 out of 36), the actual prices have fallen outside the range of expectations.[22]

Figure 3. Imported Crude Oil Prices
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 43.

Petroleum Product Prices

Retail motor gasoline price forecasts had an average absolute error of 3.7 percent or about 4 cents per gallon (Table B2). Most of the errors can be attributed to the overstatements or understatements of RAC prices, a major component of gasoline prices.

The residential heating oil price forecasts had an average absolute error of 7.4 percent over the last six *Outlooks* compared to 8.7 percent in the previous *Supplement* (Tables 10 and B3). All but one of the forecast errors were higher than expected due to lower than expected crude oil prices and to warmer-than-normal weather in the fourth quarter of 1994.

Residual fuel oil price forecasts had an average absolute error of 12.3 percent, over the last six *Outlooks* (Table B4). This was an improvement for this volatile fuel price over the 14.0 percent error reported in the previous *Supplement*. Crude oil price overstatements, accounted for most of the errors in 1993. In 1994, the price was generally underestimated as margins (the price difference between crude oil and residual fuel) were unusually high compared to the previous four years. Historically, residual fuel oil has sold for less than the price of crude oil. From 1989 through 1993, the price of crude oil was over $3 per barrel more than the price of residual fuel oil.[23] However in 1994, this difference was less than $1 per barrel (Tables B1 and B4).

Natural Gas

Forecast errors for natural gas wellhead prices have averaged a relatively high 21.8 percent over the last year and a half (Table B5). Some of the errors were partially weather related with unusually warm weather in the fourth quarter of 1994. However, much of the errors are the result of not anticipating the rapidly changing nature of the natural gas market occurring in the past few years. Among these changes are the flattening of seasonal price patterns due to more efficient inventory management and to the growth of the futures market. Other changes include the large growth of Canadian imports of natural gas, more efficiency in production and distribution, and an increase in productive capacity.

Residential natural gas price forecast errors were relatively small, averaging 2.8 percent (Table B6). The wellhead price is a small portion of the residential price (less than one-third), while distribution costs account for most of the differences in the cost of these fuels. Due to weather related demand patterns and to the rate structure, the residential price is still highly seasonal compared to the wellhead price. In most instances, the forecasts underestimated the price, with many of these errors due to understatements of the margin increases that may have been the result of the Federal Energy Regulatory Commission (FERC) Order 636. This order, which restructured the natural gas industry and should ultimately lead to a more efficient natural gas market, may have affected residential prices by temporarily shifting some of the revenue and transition costs to residential customers.

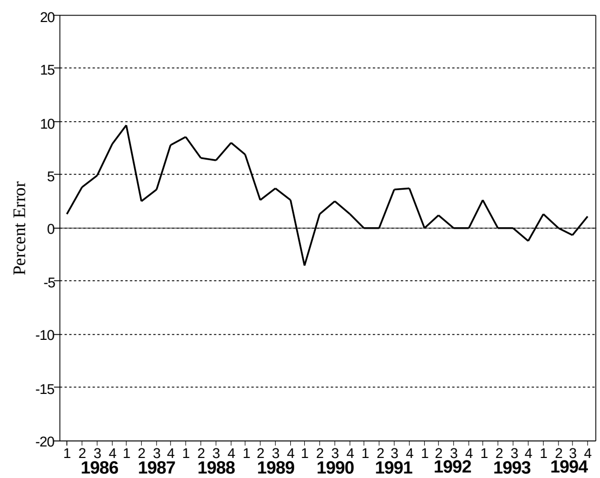
Residential Electricity

Residential electricity price forecasts, with a 0.9-percent error rate, or 0.08 cents per kilowatthour, have been among the most accurate of all the energy forecasts evaluated in the *Supplement* (Table B7). Three of the 21 forecast quarters reported in Table B7 had forecasts exactly equal to the observed actual. It should be noted though, that the electric utilities industry is highly regulated and the end-use prices of this industry have been quite stable over the last several years. Nevertheless, Figure 4 illustrates that one-year-ahead projections for this price have improved considerably over the last 9 years. The one-year-ahead projection for the first quarter of 1987 was overstated by nearly 10 percent (Figure 4). Subsequent one-year-ahead projections made for the 4th quarter of 1988 and the first quarter of 1989 were overstated by an average of over 7 percent. However, the average absolute error had improved to 1.2 percent for the one-year-ahead projections made for 1990 through 1994.

Electric Utility Coal Prices

Projections for coal prices to electric utilities have averaged a 4.3-percent error rate, compared to 3.3 percent in the previous *Supplement* (Tables 10 and B8). Due to large increases in mining productivity and a shift in production to the less expensive western surface mined coal, these utility coal prices have been trending downward over the last several years, while other fuel prices to electric utilities have fluctuated. The forecasts have consistently overstated prices, but by a relatively small amount.

Figure 4. U.S. Residential Electricity Prices
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 43.

Economic Activity Indicators and Weather

The demand for energy is highly correlated with the level of economic activity. The major economic drivers in the short-term forecasting models are the industrial production index for manufacturing and real disposable personal income. The economic forecast is developed using EIA's world oil price and other energy price assumptions to solve the DRI/McGraw-Hill (DRI) Quarterly Model of the U.S. Economy. Therefore, the EIA economic forecasts represent DRI's forecasts, except for adjustments for the different energy price assumptions.

Real Disposable Personal Income

The forecasts for real disposable personal income had an average absolute error of 0.9 percent over the six most recent forecast quarters (Table B9). Nearly all of the errors were overstated as the economy grew slightly less rapidly than had been forecasted.

The Industrial Production Index for Manufacturing

The historical (actual) numbers for 1993 for the industrial production index for manufacturing were revised in 1994. The methodology used to calculate these indices was changed and some of the historical data was revised, therefore precise comparisons between the actual value and the forecasted number cannot be made.

Weather

Weather has been a key variable affecting the whole range of energy products, including demand, stock levels, imports, production, and prices. The projections for the various energy variables in the *Outlook* assume "normal" weather in the forecast period. "Normal" is defined as a 30-year average (1961-1990) of the heating (or cooling) degree-days. Deviations from normal for heating degree-days in the winter (first and fourth) quarters are most likely to affect natural gas and distillate fuel oil demand and prices. The fourth quarter of 1994, for example, was 13.7 percent warmer than normal (Table B11). Therefore, projections for natural gas demand sales, particularly the residential and commercial sectors were somewhat overstated. Deviations from normal for cooling degree-days are most likely to affect electricity sales in the third quarter (the peak cooling season when air-conditioning is most used).

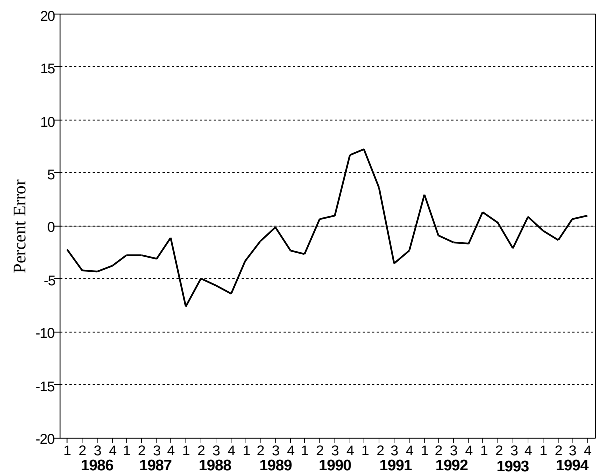
Petroleum

Demand

For the six *Short-Term Energy Outlooks* evaluated, the average absolute forecasting error for petroleum demand was 1.0 percent or 170,000 barrels per day (Table B13), an improvement over the 1.4 percent error reported in the previous *Supplement*. For the major petroleum products, the average absolute error ranged from 0.8 percent for motor gasoline, to 14.9 percent for residual fuel oil. The one-year-ahead forecasts for total petroleum demand never erred by more than 8 percent for 1986 through 1994, but the forecasts made prior to 1989 were consistently understated (Figure 5). Since the second quarter of 1991, the forecast error has always been less than 5 percent and shows much less (downward) bias.

Motor gasoline forecast errors averaged a low 0.8 percent (or 60,000 barrels per day) compared to 1.1 percent in the previous *Supplement* (Tables 10 and B14). Most of the forecast errors, albeit small, tended to understate gasoline demand. The exception was for the first quarter of 1994, when the forecast errors overstated demand. There was less driving because of severe winter weather and icy conditions on the roads for much of the East Coast during January of that year.

Figure 5. U.S. Total Petroleum Demand
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 43.

The actual number of winter quarter heating degree-days was relatively closer to the 30-year averages or "normals" than in the period evaluated in the previous *Supplement*, with the exception of the fourth quarter of 1994. These "normals" are used in projecting heating fuels demand. Thus, the average absolute percent error for distillate fuel was a relatively small 2.5 percent, better than the 2.8 percent error reported in the previous *Supplement* (Table B15). Residual fuel oil forecast errors averaged 14.9 percent (Table B16). Demand for this fuel was overstated by an average of 28.2 percent for the fourth quarter 1994. These large errors were the result of unanticipated mild weather and the switching to natural gas, as gas prices were unseasonably low due to high storage levels.

Jet fuel demand forecasts had an average error of 2.2 percent, or 30,000 barrels per day, compared to an average error of 3.8 percent in the previous report (Table B17). For the last half of 1993, the forecasts tended to overstate demand, not anticipating the continued economic troubles in the airline industry. However, all the forecasts understated demand, by an average of 5.3 percent, in the second quarter of 1994, as air travel during that period was unseasonably high.

Forecasts of demand for "other" petroleum products which include motor gasoline blending components, asphalt, road oil, petroleum coke, LPG, waxes, lubricants, unfinished oils, aviation gasoline blending components, and miscellaneous oils show an improvement. The average absolute forecasting error for this category was 2.8 percent, or 120,000 barrels per day (Table B18), compared to 3.8 percent in the previous report.

Domestic Crude Oil Production

The forecasts of crude oil production were among the most accurate of the forecasts with an average error of 1.0 percent or 60,000 barrels per day (Table B19). In the *Outlook*, domestic crude oil production is divided into two categories: Alaskan production, which comprises about 25 percent of domestic production, and Lower 48 production, which comprises the remaining 75 percent. Lower 48 production forecasts were particularly accurate with an average absolute error of 0.8 percent or 40,000 barrels per day (Table B21). Forecast errors for Alaskan production averaged 2.4 percent (Table B22).

Total Petroleum Net Imports, Excluding SPR

Forecast accuracy for net oil imports declined compared to the last *Supplement*, with an average absolute error of 4.2 percent versus 2.4 percent (Tables 10 and B22). The largest errors occurred in the fourth quarter of 1994 when mild weather reduced overall petroleum demand.

Stocks

The forecasts for petroleum inventories in the *Outlook* had an average absolute forecast error of 1.7 percent, compared to 1.5 percent in the previous *Supplement* (Table 10 and B23). However, 10 of the 21 forecast quarters had average absolute error of less than 1 percent. The first and second quarters of 1994 was overstated by an average of more than 3.5 percent as total demand was generally overstated for that period.

Natural Gas

Natural Gas Demand

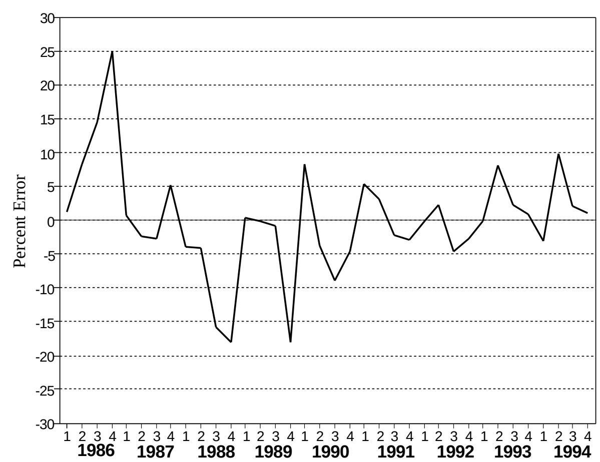
The average absolute error for the total natural gas demand forecasts was 3.2 percent (Table B24) compared to the 3.7 percent error reported in the previous *Supplement*. Demand was overstated by 6.2 percent, on average, in the second quarter of 1994 due to a mild April which lowered residential consumption.

The one-year-ahead forecasts for natural gas demand had errors higher than 20 percent for forecasts made for 1986 through 1989 (Figure 6). Since the fourth quarter of 1990, the forecast error has always been less than five percent.

Natural Gas Production

The natural gas production forecasts errors have been quite small and consistent over the last several years. The average forecast error was 2.3 percent versus 2.2 percent in the previous *Supplement* (Table B25). However, forecasts made for the fourth quarter 1993 tended to understate production by an average of over 4 percent due largely to higher than expected demand. Heating-degree-days and thus natural gas demand were also understated by more than 4 percent for this quarter.

Figure 6. U.S. Natural Gas Demand
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 43.

Coal

The total domestic coal demand forecast is a combination of forecasts of the three major consuming sectors: the coking (metallurgical) coal sector, the electric utilities sector, and the retail and general industry demand sector. Approximately 87 percent of domestic coal demand is for the generation of electricity; errors in forecasting total electricity generation and sales explain a large part of the error in the total coal forecast.[24]

The average absolute error for total domestic coal demand was 3.2 percent, or 7 million tons, compared to 2.3 percent reported in the previous *Supplement*. All six forecasts for the fourth quarter of 1994 overstated coal demand, by an average of 6.1 percent. This was due to low demand for electricity caused by the warm winter.

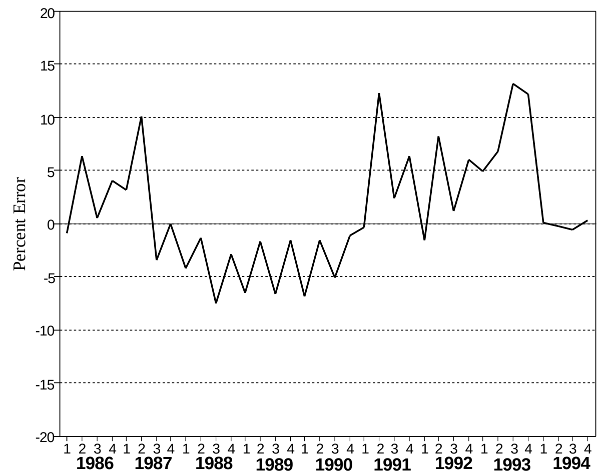
One-year-ahead forecasts made for the first quarter of 1986 through the second quarter of 1987 generally overstated production, due in part to larger than usual stock draws that resulted from anticipation of a strike that never occurred (Figure 7). The one-year-ahead forecasts for the remainder of 1987 through the first quarter of 1991, consistently understated production. The one-year-ahead forecasts for the second quarter 1991 through the fourth quarter 1993 mostly overstated production, especially in 1993 when a selective coal strike reduced production. However, the one-year-ahead forecasts for 1994 had an average absolute error of just 0.5 percent (Figure 7).

The average absolute error for total coal production was 2.5 percent (Table B27). This compares to the 7.8 percent error in the previous *Supplement*. Production was severely curtailed during the last 6 months of 1993, primarily because of the United Mine Workers of America (UMWA) strike that occurred during this period. Because the strike was unanticipated, forecasts considerably overestimated production for this period.

Electric Utilities

The average forecast error for total electricity sales was 1.9 percent which was equal to 1.9 percent in the previous report (Table B28). For the fourth quarter of 1994, almost all of the forecasts overstated sales by an average of 2.9 percent as the winter weather turned out to be milder than normal.

Figure 7. U.S. Coal Production
(One-Year-Ahead Forecast Percent Error)

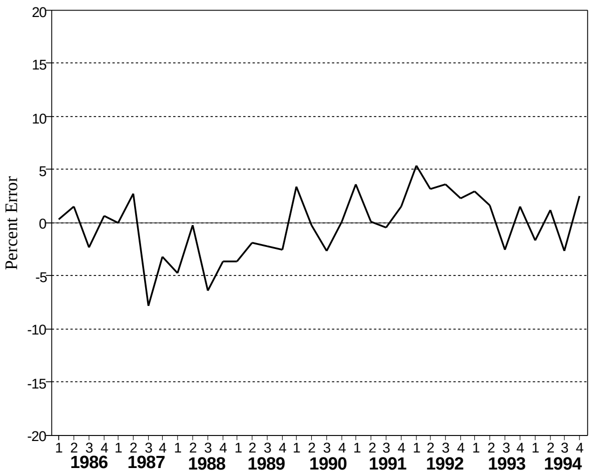


Sources: Details provided in Figure Reference section, p. 43.

The two primary factors that influence electricity sales are the economy and the weather. Of these two, the most important, and yet least predictable influence on short-term electricity sales, is the weather. The weather (in terms of heating and cooling degree-days) for purposes of the forecasts, is assumed to be normal. (See section on weather, p. 27). The accuracy of the one-year-ahead forecasts have improved slightly over the last 9 years. The average absolute error for the 16 forecasts made for 1986 through 1989 was 2.8 percent.[25] For the 20 forecasts made for 1990 through 1994, the absolute average error was 2.2 percent.[26] However, the bias of these forecasts has been changing with time. One year-ahead forecasts made for 1986-1989 were understated in 12 of 16 quarters, while forecasts made for 1990-1994 were overstated in 12 of 20 quarters (Figure 8).

Residential electricity sales (Table B29) has an average absolute forecast error of 4.0 percent, with an average overstatement of 5.9 percent in the fourth quarter of 1994, due to the mild winter. Commercial electricity sales, which are also weather-related, although to a lesser degree, were overstated by an average of 3.0 percent during the same period (Table B30). The average absolute error for commercial sales was 1.9 percent. Industrial electricity sales, which are even less sensitive to weather, had an average absolute forecast error of just 0.7 percent and an average error of 0.8 percent in the fourth quarter of 1994 (Table B31).

Figure 8. U.S. Electricity Demand
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 43.

The accuracy of the electricity sales forecast determines the accuracy of electricity generation by fuel source. Thus, if sales are overestimated, so, obviously, is total generation. Coal generation (more than half of total generation) is tied to this total and to forecasts for nuclear and hydroelectric power. These two latter sources are determined independently. Electricity generation from coal had a an average error of 3.8 percent (Table B32). The largest portion of this error occurred in the fourth quarter of 1994 (overstated by 8.1 percent) when the unusually mild weather resulted in smaller-than-normal sales which led to an overestimation of total generation. Electricity generation from petroleum (primarily residual fuel oil) had an average error of 37.9 percent (Table B33) compared to 20.3 percent in the previous *Supplement*. This rather high error was generally caused by the overstatements or understatements of forecasts for total electricity sales. Because the petroleum share of total generation is by far the smallest of the principal electricity generation sources, a relatively high percent error can be expected as a result of errors in total demand, especially if peak demands are reduced with mild weather or vice versa, such as in the fourth quarter of 1994 where the average error was nearly 75 percent.

Electricity generation from natural gas had an average absolute error rate of 6.4 percent compared to 11.5 in the previous *Supplement* (Table B34). Forecasts for the third quarter of 1994 were the least accurate with an error rate of 10.3 percent. This was the result of the underestimation of the relative price difference between natural gas and residual fuel oil which in turn led to an overstatement of switching to residual fuel. (Tables B30, B4, and B7).

Nuclear generation was projected by determining the nuclear capacity operating during a period and applying an estimated average utilization rate. This capacity factor was derived by examining its historical trend. The absolute average error rate was 4.8 percent (Tables B35 and B32).

Hydroelectric power had an average absolute forecast error of 11.4 percent, compared to the 10.9 percent error in the previous *Supplement* (Table B36). All of the forecasts were overstated. The hydroelectric power forecast is greatly affected by the assumption of normal precipitation. A severe drought in the northwest portion of the country caused actual generation to fall below the forecasted value for the past few years.

Notes: Chapter 4

[21]Generally, three forecasts, based on three different scenarios for world oil prices, are presented in each *Outlook*. Only the base or "mid" case scenario is evaluated in this analysis.

[22]Actual Data: Compiled from monthly data used in publication of Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380, Table 1. Projected Data: *Short-Term Energy Outlook*, DOE/EIA-0202, issues 85/1Q through 93/4Q, low and high imported crude oil price cases.

[23] Energy Information Administration, *Historical Monthly Energy Review*, DOE/EIA-0035(73-92), Tables 9.1 and 9.5b, *Monthly Energy Review*, DOE/EIA-0035(95/02), Tables 9.1 and 9.6.

[24]*Monthly Energy Review*, DOE/EIA-0035(95)/04, Table 6.2. For the years 1990-1994, coal consumption at electric utilities averaged 87 percent of total consumption.

[25]**History**: Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226, various issues, Table 3. **Projections**: Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 85/1Q through 89/4Q.

[26]**History**: Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226, various issues, Table 3. **Projections**: Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 90/1Q through 93/4Q.

5. Oxygenate Supply/Demand Balances in the Short-Term Integrated Forecasting Model

The blending of oxygenates, such as fuel ethanol and methyl tertiary butyl ether (MTBE), into motor gasoline has increased dramatically in the last few years because of the oxygenated and reformulated gasoline programs.[27] Because of the significant role oxygenates now have in petroleum product markets, the *Short-Term Integrated Forecasting System (STIFS)* has been revised to include supply and demand balances for fuel ethanol and MTBE. The *STIFS* model is used for producing forecasts in the *Short-Term Energy Outlook.* A review of the historical data sources and forecasting methodology for oxygenate production, imports, inventories, and demand is presented below.

Fuel ethanol and MTBE usage has grown steadily since the early 1980's in response to octane demand resulting initially from the phaseout of lead from gasoline and later from rising demand for premium gasoline. Federal and local tax incentives for blending renewable fuels into motor gasoline have contributed to the growth in demand for fuel ethanol. The oxygenated and reformulated gasoline programs stimulated a dramatic increase in oxygenate demand and production capacity between 1991 and 1995 (Table 11). Oxygenates are now projected to account for over 4 percent of the finished motor gasoline pool in 1995 (Table 12).

Oxygenate Demand

The recent growth in oxygenate blending into motor gasoline has been demand-driven because of the minimum oxygen content mandates in the oxygenated and reformulated gasoline programs. Oxygenated gasoline must contain a minimum 2.7 percent oxygen by weight while reformulated gasoline requires a minimum 2.0 percent oxygen by weight. Supply and demand projections for fuel ethanol and MTBE begin with estimates of total oxygenate demand.

Oxygenate demand forecasts are based on estimated market shares for the following types of motor gasoline:

· Oxygenated motor gasoline
· Reformulated motor gasoline (RFG)
· Oxygenated program reformulated motor gasoline (OPRG)
· Gasohol and conventional motor gasoline octane demand

Estimates of market shares for the regulated gasolines (oxygenated motor gasoline, RFG, and OPRG) generally begin with estimates of the fraction of the U.S. population that reside in each nonattainment area that require one of the regulated gasolines. Calculated population shares must then be corrected to arrive at motor gasoline demand shares because per capita demands vary throughout the country. For example, the District of Columbia contains 0.24 percent of the U.S. population but represents only 0.15 percent of the U.S. retail motor gasoline market. Wyoming, on the other hand, has a retail gasoline market share that is over 1.5 times its population share. Population share correction factors were estimated for each State using motor gasoline demand shares calculated from Federal Highway Administration (FHWA) 1993 motor gasoline sales data.[28] Finally, estimated nonattainment area motor gasoline demand shares are then adjusted for factors that may alter demand, including spill over (delivery of regulated motor gasoline to areas that do not require it), changes in automobile fuel efficiency, and price elasticity of demand.[29] Table 13 provides a sample of this estimation method for OPRG for January 1995. Projected U.S. motor gasoline demand shares for the regulated gasolines range from an aggregate of about 30 percent in the Summer to over 42 percent in the Winter (Table 14).

Regulated gasoline demand shares are converted to monthly volumes using the forecast of refinery output of motor gasoline generated by the *STIFS* model.[30] Because there is about a one month lag between production of motor gasoline at refineries and retail sale, demand shares are lagged one month to convert them to production shares. In other words, while 3.61 percent of the motor gasoline sold at retail outlets in October 1995 should be OPRG, refineries are expected to produce this grade of regulated gasoline in September 1995.

Because fuel ethanol and MTBE have different oxygen contents, volumetric oxygenate demands are usually presented on an MTBE-equivalent basis. About 2 gallons of MTBE have the same oxygen content as 1 gallon of ethanol.[31] Oxygenated motor gasoline and OPRG are assumed to contain 15.2 percent MTBE by volume, and RFG is assumed to require 11.7 percent MTBE by volume.[32] Given estimates of total refinery production of motor gasoline, regulated gasoline production shares, and required oxygenate content,

Table 11. Oxygenate Production Capacity and Demand
(Thousand Barrels per Calendar Day)

Oxygenate Production Capacity:

	Ethanol	MTBE	TAME	ETBE
January 1, 1991	82.6	122.5	0.5	0.0
January 1, 1992	93.5	135.1	3.7	0.0
January 1, 1993	87.0	182.2	5.0	0.8
January 1, 1994	90.7	226.7	14.5	0.8
January 1, 1995 Projection	103.7	269.6	20.6	0.8

Annual Average Demand:

	Ethanol	MTBE
1990	49	81
1991	56	76
1992	68	95
1993	75	166
1994	83	158

Notes: · TAME (tertiary amyl methyl ether) and ETBE (ethyl tertiary butyl ether) production numbers are withheld by the Energy Information Administration to avoid disclosure of individual company data.

Sources · Capacities from Energy Information Administration, *Petroleum Supply Annual 1993*, Volume 1, DOE/EIA-0340(93)/1 (Washington, DC, May 1994), p. 130, and earlier issues.
· Ethanol demand for 1990 and 1991 estimated from State gasohol sales, Federal Highway Administration, *Highway Statistics 1992*, FHWA-PL-93-023 (Washington, DC, 1993), p. 11.
· MTBE demand estimates for 1990 and 1991 supplied by DeWitt & Company, Inc.
· Ethanol and MTBE demands for 1992 through 1994 are calculated from import, inventory, and production data, Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(94/11) (Washington, DC, November 1994), pp. 70, 92, 100-101, and 136-137, and earlier issues.

oxygenate demand for blending into regulated motor gasoline can be derived.

Continued demand for ethanol in gasohol blending, and demand for MTBE as an octane blendstock, is added to the demand for oxygenates in regulated motor gasolines to arrive at total oxygenate demand. A simple forecast of continued demand for oxygenates in gasohol and octane blending of 100 thousand barrels per day MTBE-equivalent volume during the summer months and 80 thousand barrels per day during the winter is assumed (pending correction once actual market behavior is observed).[33]

The sum of oxygenate demand for regulated motor gasolines, gasohol, and octane blending equals total oxygenate demand:

$$\begin{aligned} OZTCPUS = {} & 0.152 * (OXFRAC+OPFRAC) * MGROPUS \\ & + 0.117 * RFFRAC * MGROPUS \\ & + OZTCPAD \end{aligned}$$

where:

OPFRAC = Oxygenated program RFG production share, fraction
OXFRAC = Oxygenated gasoline production share, fraction
OZTCPUS = Total oxygenate demand, million barrels per day MTBE-equivalent volume
MGROPUS = Refinery output of finished motor gasoline, million barrels per day
RFFRAC = Reformulated gasoline production share, fraction
OZTCPAD = Oxygenate demand for gasohol and octane blending, million barrels per day MTBE-equivalent volume (80 to 100 thousand barrels per day assumed)

Note: Regulated gasoline production shares = demand shares lagged one month.

Table 12. *Short-Term Energy Outlook* 95/2Q Oxygenate Forecasts

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Motor Gasoline Refinery Output (thousand barrels per day)												
1995	7,411	7,304	7,281	6,954	7,311	7,471	7,470	7,449	7,525	7,415	7,587	7,600
1996	7,324	7,131	7,113	7,246	7,369	7,541	7,504	7,471	7,536	7,499	7,692	7,739
Total Oxygenate Demand (thousand barrels per day MTBE-equivalent volume)												
1995	446	383	366	345	357	363	363	364	452	512	521	522
1996	453	416	398	396	401	408	406	407	486	517	528	531
Ethanol Plant Production (thousand barrels per day)												
1995	98	100	90	90	90	90	90	90	90	90	90	90
1996	90	90	90	90	90	90	90	90	90	90	90	90
Ethanol End-of-Month Stocks (million barrels)												
1995	2,699	3,034	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100
1996	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100
MTBE Plant Production (thousand barrels per day)												
1995	149	135	170	170	170	170	170	190	220	240	240	240
1996	240	190	190	190	190	190	190	200	230	240	240	240
MTBE End-of-Month Stocks (million barrels)												
1995	12,123	11,342	12,122	13,625	14,789	15,745	16,735	18,298	18,073	16,630	14,948	13,188
1996	13,564	13,548	14,056	14,630	15,067	15,280	15,546	16,094	15,176	13,555	11,664	9,628

Sources: Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(95/2Q) (Washington, DC, May 1995), unpublished forecast data generated by the *Short-Term Integrated Forecasting System (STIFS)* model.

Total oxygenate demand is then disaggregated into ethanol and MTBE (and other ethers) demands based on the assumption that ethanol demand is supply-driven and that MTBE and other ethers satisfy the remaining demand.

Fuel Ethanol Supply and Demand Balance

The *STIFS* fuel ethanol balance involves the following 5 variables:

EOPRPUS = Fuel ethanol plant production, million barrels per day
EOFPPUS = Fuel ethanol field production, million barrels per day
EONIPUS = Fuel ethanol net imports, million barrels per day
EOPSPUS = Fuel ethanol end-of-month stocks, million barrels
EOTCPUS = Fuel ethanol product supplied (demand), million barrels per day

The EIA began collecting monthly ethanol plant production and end-of-month inventory statistics beginning January 1992, and monthly fuel ethanol imports in January 1993 (Table 15). Fuel ethanol demand for gasoline blending, EOTCPUS, is calculated from a material balance around production, imports, and stock change:[34]

$$EOTCPUS = EOPRPUS + EONIPUS - \Delta\ EOPSPUS$$

Most fuel ethanol blending into motor gasoline takes place at terminals and racks (often referred to as "splash" blending) that are not included in the EIA Petroleum Supply Reporting System. Fuel ethanol splash blending is classified as field production in the EIA *Petroleum Supply Monthly* and is obtained from the following identity:

$$EOFPPUS = EOTCPUS - \text{Refinery Inputs of Fuel Ethanol}$$

Refinery inputs of fuel ethanol are not explicitly identified in EIA publications. However, total field

Table 13. Estimated Oxygenated RFG (OPRG) Demand Shares, January 1995

State	Nonattainment Area	Nonattainment Area Population	U.S. Population Share		Population Correction Factor		Estimated Gasoline Demand Share
MD	Baltimore CMSA	2,382,172	0.0096	x	0.941	=	0.0090
NY	New York City CMSA	11,463,705	0.0461	x	0.670	=	0.0309
CT	New York City CMSA	961,524	0.0039	x	0.909	=	0.0035
NJ	New York City CMSA	5,662,022	0.0228	x	0.824	=	0.0188
PA	Philadelphia CMSA	3,728,909	0.0150	x	0.851	=	0.0128
MD	Philadelphia CMSA	71,347	0.0003	x	0.941	=	0.0003
NJ	Philadelphia CMSA	1,657,143	0.0067	x	0.824	=	0.0055
DC	Washington CMSA	606,000	0.0024	x	0.631	=	0.0015
MD	Washington CMSA	1,789,029	0.0072	x	0.941	=	0.0068
VA	Washington CMSA	1,527,645	0.0061	x	1.084	=	0.0067
NJ	Atlantic City MSA	319,416	0.0013	x	0.824	=	0.0011
NJ	Warren County	91,607	0.0004	x	0.824	=	0.0003
Total unadjusted OPRG share of total U.S. motor gasoline retail market							0.0970
Correction for spill over, elasticity, and fuel efficiency reduction							x 1.04
Total adjusted OPRG share of total U.S motor gasoline retail market							0.1009

Notes: CMSA - Consolidated Metropolitan Statistical Area.
MSA - Metropolitan Statistical Area.
Population Correction Factor = State Gasoline Demand Share / State Population Share.
Total U.S. population = 248,710,519.
Totals may not equal sum of components due to independent rounding.

Sources:
Population: U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States 1992* (112th Edition) (Washington, DC, 1992), pp. 20, 30-32.
State Gasoline Demands: Federal Highway Administration, *Highway Statistics 1993*, FHWA-PL-94-023 (Washington, DC, 1994), p. I-8. Annual data were used to calculate demand shares and no attempt was made to account for seasonality in State per capita demands.

production of fuel ethanol can be calculated from the *Petroleum Supply Monthly* using the identity:[35]

EOFPPUS	=	MBFPPUS + MGFPPUS
MBFPPUS	=	Field production of motor gasoline blend components
MGFPPUS	=	Field production of finished motor gasoline

There are several other sources for fuel ethanol supply statistics that may be used to supplement EIA survey data (Table 16). However, because of the lack of monthly data for some of the series some simplifying assumptions are made for the *STIFS* historical database:

- End-of-month stocks are assumed to be constant at 1 million barrels for all months before January 1992.
- Net imports = 0, for all months before January 1993.
- Refinery inputs of ethanol = 0, for all months before January 1993.

Given these assumptions, fuel ethanol demand equals fuel ethanol plant production. Although fuel ethanol demand calculated from gasohol sales reported by the Federal Highway Administration (FHWA) from State reports of excise tax receipts may be understated, comparison to demand imputed from Bureau of Alcohol, Tobacco, and Firearms (ATF) and EIA data indicate reasonable closeness. Because the FHWA data are available on a monthly basis, these data were used for fuel ethanol production/demand history before January 1992.

The *Short-Term Energy Outlook's* 2nd quarter 1995 forecast for ethanol production is assumed to remain flat at 90 thousand barrels per day over the forecast period (through the end of 1996). Net imports are

Table 14. Projected Regulated Gasoline Demand Shares, 1995
(Fraction of Total U.S. Motor Gasoline Demand)

Month	Oxygenated	Reformulated	Oxygenated/ Reformulated	Total Regulated Gasoline
January	0.0739	0.2469	0.1009	0.4216
February	0.0617	0.1997	0.1009	0.3623
March	0.0145	0.2648	0.0357	0.3151
April	0.0000	0.2648	0.0357	0.3006
May	0.0000	0.3006	0.0000	0.3006
June	0.0000	0.3006	0.0000	0.3006
July	0.0000	0.3006	0.0000	0.3006
August	0.0000	0.3006	0.0000	0.3006
September	0.0016	0.3006	0.0000	0.3022
October	0.0319	0.3120	0.0357	0.3796
November	0.0739	0.2469	0.1009	0.4216
December	0.0739	0.2469	0.1009	0.4216

Note: California oxygenated gasoline is included in reformulated gasoline demand share because of the State's 2.0 weight percent limit on motor gasoline oxygen content.

Table 15. EIA Fuel Ethanol Monthly Statistics

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plant Production (thousand barrels per day)												
1992	78	71	68	68	68	66	66	70	67	74	74	75
1993	76	73	77	76	74	76	69	66	72	76	85	85
1994	82	82	80	73	77	79	75	79	89	91	98	97
Field Production (thousand barrels per day)												
1992	68	68	62	68	55	64	52	66	54	76	91	100
1993	61	68	70	61	58	63	62	48	67	69	84	80
1994	86	73	76	48	22	63	65	73	58	90	82	82
Imports (thousand barrels per day)												
1993	1.5	0.0	1.5	0.0	0.0	1.6	0.8	0.0	0.6	1.6	0.0	0.4
1994	1.9	0.0	0.8	0.0	0.0	0.0	0.8	2.2	0.0	1.5	0.0	1.8
End-of-Month Stocks (thousand barrels)												
1992	1,076	1,287	1,462	1,457	1,858	1,941	2,362	2,530	2,973	2,980	2,547	1,791
1993	2,059	1,946	1,929	2,152	2,441	2,627	2,706	2,941	2,805	2,810	2,335	2,114
1994	1,879	1,708	1,672	1,484	1,526	1,702	1,822	1,818	2,694	2,302	2,350	2,378

Sources: Energy Information Administration
· Plant production and 1992 stocks: *Weekly Petroleum Status Report*, DOE/EIA-0208 (Washington, DC, various issues), Table B2.
· Field production, imports, and 1993/1994 stocks: *Petroleum Supply Monthly*, DOE/EIA-0290 (Washington, DC, various issues), Tables 4, 33, and 51, respectively.

Table 16. Comparison of Historical Fuel Ethanol Annual Statistics

	Production		Exports	Imports		Stocks	Demand	Imputed Demand	
Source	**ATF**	**EIA**	**ATF**	**ATF**	**EIA**	**EIA**	**FHWA**	**ATF**	**EIA**
1994	-	83	-	-	0.8	2,378	-	-	83
1993	-	75	-	-	0.7	2,114	64	-	75
1992	62	68	0.4	2.4	-	1,791	58	64	68
1991	55	-	2.8	0.8	-	-	56	53	-
1990	70	65	8.6	1.0	-	2,526	49	62	65
1989	46	-	0.7	1.5	-	-	45	47	-
1988	51	-	0.8	0.6	-	-	53	51	-
1987	49	-	1.2	1.3	-	-	52	49	-
1986	60	-	0.2	6.5	-	-	51	66	-
1985	48	-	0.2	5.2	-	-	51	53	-

Notes:
- · Stocks are for last day of calendar year, in thousands of barrels
- · Production, exports, imports, and demands are in thousands of barrels per day
- · FHWA fuel ethanol demand = 0.10 x total gasohol sales reported by States
- · Imputed demand = Production + Imports - Exports - Stock Change
  ATF imputed demand assumes no stock change
  EIA imputed demand assumes no exports (or stock change in 1990 and 1992)

Sources:
- ATF Bureau of Alcohol, Tobacco, and Firearms, *Monthly Distilled Spirits Report*, Report Symbol 76 and *Alcohol Fuels Report*, internal quarterly report.
- EIA Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(95/01) (Washington, DC, January 1995), Table D3, and earlier issues.
- FHWA Federal Highway Administration, *Highway Statistics 1993*, FHWA-PL-94-023 (Washington, DC, 1994), p. I-9, and earlier issues.

assumed to be 0, and inventories are assumed to remain constant at the most recent level reported in the *Petroleum Supply Monthly*.

Thus, fuel ethanol demand for the forecast period equals fuel ethanol production. Refinery inputs are assumed to average 10 thousand barrels per day, and field production 80 thousand barrels per day. Some seasonality may be imposed on these naive production and stock forecasts once experience with fuel ethanol supply to the RFG program is obtained.

MTBE and Other Ethers Supply and Demand Balance

The *STIFS* balance for MTBE and other ethers involves the following 4 variables:

MTPRPUS = MTBE production, million barrels per day
MTNIPUS = MTBE net imports, million barrels per day
MTPSPUS = MTBE end-of month stocks, million barrels
MTTCPUS = MTBE product supplied (demand), million barrels per day

EIA began collecting MTBE data at the same time as the fuel ethanol data (Table 17). The MTBE data do not include a difference between plant production and field production as in the fuel ethanol balance because all MTBE production is assumed to be captured in the EIA's Petroleum Supply Reporting System.

MTBE supply history before January 1992 is more scant than that for fuel ethanol. Monthly gross imports for 1992 and gross exports for 1992 and 1993 were obtained from the *Oil Market Listener*.[36] Estimates of annual average MTBE production, gross imports and gross exports for 1985 through 1991 were provided by DeWitt and Company, Inc. The annual average production data were disaggregated into monthly volumes by fitting a cubic spline curve. MTBE net imports are assumed to average 3 thousand barrels per day in 1991, and 0 for all months before January 1991. MTBE stocks are assumed to remain constant at 1 million barrels for

Table 17. EIA MTBE Monthly Statistics

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plant Production (thousand barrels per day)												
1992	98	94	89	79	90	90	101	91	104	118	128	125
1993	115	114	112	138	132	126	155	142	157	146	148	144
1994	123	140	129	140	139	115	154	166	160	164	150	144
Imports (thousand barrels per day)												
1993	27	22	14	3	19	24	16	18	28	14	29	24
1994	25	43	16	37	30	33	36	32	32	27	34	70
Exports (thousand barrels per day)												
1994	5	4	8	7	15	8	10	20	12	15	13	13
End-of-Month Stocks (thousand barrels)												
1992	11,999	12,681	13,966	14,962	15,961	18,887	20,436	23,131	22,853	19,208	16,342	13,818
1993	11,985	10,628	11,351	12,063	13,529	14,487	16,649	17,416	15,589	14,340	12,718	10,035
1994	8,800	8,676	10,897	12,610	13,334	15,097	19,518	21,374	21,547	20,014	16,540	13,769

Sources: Energy Information Administration
· Plant production and 1992 stocks: *Weekly Petroleum Status Report*, DOE/EIA-0208 (Washington, DC, various issues), Table B3.
· Imports, Exports, and 1993-1994 Stocks: *Petroleum Supply Monthly*, DOE/EIA-0290 (Washington, DC, various issues), Tables 33, 45, and 51, respectively. Exports are reported in *Petroleum Supply Monthly*, Table 45 as "Other Hydrocarbons/Oxygenates" and may include ethanol exports.

all months before December 1990, and then increase steadily at about 1 million barrels per month through January 1992.

Historical MTBE demand is calculated from a material balance around production, net imports (imports - exports), and stock change:

MTTCPUS = MTPRPUS + MTNIPUS Δ MTPSPUS

The MTBE demand forecast is derived from the difference between estimated total oxygenate demand and assumed ethanol demand (converted to MTBE-equivalent volume):

MTTCPUS = OZTCPUS - 2.0 * EOTCPUS

MTBE net imports are assumed to remain constant at 45 thousand barrels per day over the forecast period. An MTBE production forecast is assumed, and adjusted to produce a reasonable stock path. These exogenously specified production and stock numbers may be converted to estimated regression equations once some production history is accumulated.

Refinery Balances

The MTBE and fuel ethanol balances are converted into aggregates that correspond to volumes reported in the *Petroleum Supply Monthly* and the *Short-Term Energy Outlook*. Table 18 provides a summary of the correspondence between variable names in the *STIFS* model and volume categories reported in the *Petroleum Supply Monthly*.

Field Production: Field production of other hydrocarbons/oxygenates is one of 6 categories of field production reported in the *Petroleum Supply Monthly* and modeled in *STIFS* (other categories include crude oil, pentanes plus, liquefied petroleum gases, motor gasoline blend components, and finished motor gasoline). All MTBE production and a small volume of ethanol blended into motor gasoline at refineries are included in the category field production of other hydrocarbons/oxygenates. Field production of other hydrocarbons/oxygenates (OHRIPUS) is estimated in the *STIFS* model as a linear function of MTBE production (MTPRPUS), a dummy variable representing January 1993 (when the new MTBE inventory survey data was incorporated into the *Petroleum Supply Monthly*), and monthly dummies:

$$\begin{aligned} OHRIPUS = {} & a_0 + a_1 * MTPRPUS \\ & + a_2 * D9301 \\ & + a_i * \text{monthly dummies} \end{aligned}$$

The estimated coefficient for MTBE production is slightly greater than 1.1 (Table C1). We expect the coefficient on MTBE production to equal 1.0 because all MTBE production is counted as field production. The estimated coefficient is within 2 standard deviations of the expected value.

Refinery Inputs: Six categories of refinery inputs are modeled in *STIFS*: crude oil, pentanes plus, liquefied petroleum gases, unfinished oils, aviation gas blending components, and "other" petroleum products. The other petroleum products category includes other hydrocarbons/oxygenates and motor gasoline blending components. Refinery inputs of other petroleum products averaged 158 thousand barrels per day in 1994.[37] Refinery inputs of other hydrocarbons/oxygenates average 199 thousand barrels per day and refinery inputs of motor gasoline blend components averaged -41 thousand barrels per day.

Refinery inputs of other petroleum products (PSRIPUS) is estimated as a function of MTBE demand (MTTCPUS), field production of motor gasoline blend components (MBFPPUS), and monthly dummies:

$$\begin{aligned} PSRIPUS = {} & a_0 + a_1 * MTTCPUS \\ & + a_2 * MBFPPUS \\ & + a_i * \text{monthly dummy variables} \end{aligned}$$

The estimated coefficient for MTBE demand is 0.74 (Table C2). The expected value for this coefficient is less than 1.0. Although MTBE blended into finished motor gasoline (i.e., MTBE demand) is reported as a refinery input, MTBE blending may displace other motor gasoline blend components such as aromatics used for octane enhancement. Thus, the net increase in refinery inputs of other petroleum products will be less than the increase in refinery inputs of MTBE.

The *STIFS* model also includes an estimating equation for the subcategory refinery inputs of other hydrocarbons/oxygenates (OXRIPUS), which is estimated as a function of MTBE demand (MTTCPUS) and monthly dummies:

$$\begin{aligned} OXRIPUS = {} & a_0 + a_1 * MTTCPUS \\ & + a_i * \text{monthly dummy variables} \end{aligned}$$

The estimated coefficient for MTBE demand is 0.52 (Table C3), which is significantly less than the expected value of 1.0. The low value arises because of the inclusion of a 1st-order auto regression (AR-1) coefficient to correct for autocorrelation in the regression errors (residuals). Without the AR-1 correction, the estimated value of the coefficient for MTBE demand is 1.18, with a standard error of 0.043.[38]

Inventories: Inventories of MTBE (MTPSPUS) and fuel ethanol (EOPSPUS) are aggregated into total oxygenate stocks (OXPSPUS). Also included in this category are stocks of other oxygenates such as methanol, which are assumed to remain constant at 700 thousand barrels through the forecast period:

$$OXPSPUS = EOPSPUS + MTPSPUS + 0.700$$

Total oxygenate stocks are then added to stocks of other hydrocarbons/hydrogen to yield total stocks of other hydrocarbons/hydrogen/oxygenates (OHPSPUS). Stocks of other hydrocarbons/hydrogen are assumed to remain constant at 50 thousand barrels through the forecast period:

$$OHPSPUS = OXPSPUS + 0.050$$

Areas of Further Development

The strong simplifying assumptions in the preparation of the historical database and some of the forecast series obviously introduce some error into the model balances and forecasts generated by the *STIFS* model. Improvements should be possible once some experience with supply and demand for oxygenates under the reformulated gasoline program is accumulated. This additional history should also improve some of the regression model results that rely on autoregression coefficients to correct for serial correlation in the regression errors.

Table 18. Correspondence Between *STIFS* Model Variables and *Petroleum Supply Monthly*, Tables 2 and 4

	Supply			Disposition			
	Field Production	Refinery Production	Imports	Stock Change	Refinery Inputs	Exports	Product Supplied
Other Liquids							
Other Hydrocarbons/Oxygenates	OHRIPUS	--	PSIMPUS*	Δ OHPSPUS	OXRIPUS	PSEXPUS*	0
Motor Gasoline Blend. Comp.	MBFPPUS	--	PSIMPUS*	Δ MBPSPUS	PSRIPUS*	PSEXPUS*	0
Finished Petroleum Products							
Finished Motor Gasoline	MGFPPUS	MGROPUS	PSIMPUS*	Δ MGPSPUS	--	MGEXPUS	MGTCPUS
Reformulated	n/a	n/a	n/a	n/a	n/a	n/a	MGZCPUS
Oxygenated	n/a	n/a	n/a	n/a	n/a	n/a	MGZCPUS
Other	n/a	n/a	n/a	n/a	n/a	n/a	MGZCPUS

Notes: n/a - Not modelled in Short-Term Integrated Forecasting System

* Aggregation includes other product classifications not shown above:

PSIMPUS = Imports of other petroleum products includes all imports except crude oil, pentanes plus, LPG's, unfinished oils, motor gasoline, jet fuel, distillate fuel and residual fuel

PSRIPUS = Refinery inputs of other petroleum products includes other hydrocarbons/oxygenates

PSEXPUS = Exports of other petroleum products covers same products as imports category (see PSIMPUS)

Notes: Chapter 5

[27] For reviews of the oxygenated and reformulated motor gasoline program requirements and oxygenate supply and demand issues refer to Energy Information Administration, "Demand, Supply, and Price Outlook for Oxygenated Gasoline," *Short-Term Energy Outlook Annual Supplement 1992*, DOE/EIA-0202(92) (Washington, DC, June 1992), pp. 3-10; "The Economics of the Clean Air Act Amendments of 1990: Review of the 1992-1993 Oxygenated Motor Gasoline Season," *Monthly Energy Review*, DOE/EIA-0380(94/05) (Washington, DC, August 1993); and "Demand, Supply, and Price Outlook for Reformulated Motor Gasoline, 1995," *Short-Term Energy Outlook Annual Supplement 1994*, DOE/EIA-0202(94) (Washington, DC, August 1994), pp. 3-20.

[28] An equivalent description of this method is that the fraction of a State's population that resides in a nonattainment area is multiplied by the State's share of the U.S. retail gasoline market.

[29] Energy Information Administration, "Demand, Supply, and Price Outlook for Reformulated Gasoline, 1995," *Monthly Energy Review*, DOE/EIA-0035(94/07) (Washington, DC, July 1994) pp. 4-5.

[30] Energy Information Administration, *Short-Term Integrated Forecasting System 1993 Model Documentation Report*, DOE/EIA-M041(93) (Washington, DC, May 1993), pp. 30-31.

[31] The volumetric ratio between MTBE and ethanol may vary by ±0.05 depending on the assumed ethanol and MTBE product purities.

[32] These percentages may change by as much as ± 0.5 percent absolute (i.e., MTBE in oxygenated gasoline may range from 14.7 to 15.7 volume percent) depending on the density of the motor gasoline, the purity of the oxygenate, and the assumed average oxygen content.

[33] Energy Information Administration, "Demand, Supply, and Price Outlook for Reformulated Gasoline," *Monthly Energy Review*, DOE/EIA-0035(94/07) (Washington, DC, July 1994) p. 8.

[34] EIA reports only gross imports of fuel ethanol in the *Petroleum Supply Monthly* (Table 33). Net imports are assumed to equal gross imports in the *STIFS* historical database (i.e., gross exports are assumed to be zero).

[35] Energy Information Administration, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93)/1 (Washington, DC, June 1994), pp. 153-154.

[36] Energy Information Ltd., "US MTBE Imports Remain Strong While Stocks Rebuild With End of Oxy Season," *Oil Market Listener* (San Francisco, CA, April 6, 1994.

[37] Energy Information Administration, *Petroleum Supply Monthly*, DOE-EIA-0109(95/02) (Washington, DC, February 1995), p. 39.

[38] The Durbin-Watson statistic on the estimated equation without the AR-1 correction is 1.298.

6. An Econometric Analysis of Short-Term Interfuel Substitution in the United States

Abstract

Nonlinear price elasticities from flexible functional forms often result in curvature violations. Proof that the linear logit model of cost shares yields downward sloping demand curves at all observations if the curvature conditions are satisfied at a base point of approximation is provided. It is demonstrated that simple linear combinations of the estimated parameters yield Morishima elasticities of substitution. Since the share system is approximated and not the cost function, these parameters are not equal to the same constant as for an integrable cost function. These features may be useful in applied general equilibrium studies.

The empirical analysis involves the short-run demand for energy in the residential, commercial, industrial, and electric utility sectors in the United States. The models are estimated with monthly data having large seasonal variation in cost shares, which leads to curvature violations in the translog model. With the logit model, however, the demand curves have proper curvature across all four sectors for all observations. Estimation results include very limited substitution possibilities between fuels in the residential and commercial sectors but considerably greater substitution in the industrial and electric utility sectors. Model simulations demonstrate a superior fit over the sample period, stable projections out of sample, and sensible responses in fuel demands to weather, income, and output shocks.

Introduction

Estimating the demand for energy for policy analysis and forecasting poses several problems that are difficult to surmount with conventional functional forms for demand systems, such as the translog (TL) and generalized Leontief (GL). Their nonlinear price elasticities often result in counter-intuitive results, such as positive own price elasticities, particularly with volatile monthly data. In addition, incorporating dynamic adjustments in quantities demanded is impossible using the TL and highly restrictive for the GL. A dynamic specification within a short-run context is essential because it is unlikely that energy consumers would respond fully to shocks within one period. This chapter provides analytical and empirical evidence that the linear logit (LL) model of cost shares developed by Considine and Mount (1984){1} provides an attractive alternative to conventional demand systems. Specifically, it is shown that the LL own price elasticities are negative if the concavity conditions hold at the point of symmetry. This property obviates complex parameter restrictions to ensure proper curvature. In the empirical analysis, demands for energy in the residential, commercial, industrial, and electric utility sectors of the U. S. economy are estimated using monthly data from 1988 to 1994.

The next section presents the basic model. The curvature properties of the model and dynamic adjustments are described. Also discussed are estimates of the demand elasticities. An evaluation of the forecasting properties of the model using a mean squared error decomposition on a static simulation within the sample is done. Finally, a 24 month forecast of energy demand, compared with a recent forecast from the Energy Information Administration is generated.

Modeling Short-Term Energy Demand

The focus of this chapter is on interfuel substitution so the demand for transportation fuels, gasoline and diesel fuel, are not considered in this paper. A two-stage optimization framework is adopted. First, an aggregate energy demand relationship in each sector is assumed as the simple log-linear function:

$$\begin{aligned} \ln Q_t = \beta \ln P_t + \gamma \ln Y_t + \sum_{k=h,c} \upsilon_k Z_{kt} \\ + \tau T_t + \varphi \ln Q_{t-1} \end{aligned} \qquad (1)$$

where:

P_t = divisia index of aggregate fuel prices in each sector,
Y_t = either income, output, or employment in each sector,
Q_t = total energy quantity in period t,
Z_{kt}= heating and cooling degree days, respectively, and
T_t = time trend.

An alternative specification involves either an expenditure function in the residential sector or a cost function for the other sectors in which energy substitutes with other goods or inputs, such as labor and capital, in production. Data limitations precluded this approach.

By definition, the product of aggregate energy consumption and price is energy expenditure, or cost, which expressed in logarithms is as follows:

$$\ln C_t = \ln Q_t + \ln \mathbf{P}_t \tag{2}$$

where :

$$\ln \mathbf{P}_t = \sum_{i=1}^{n} S_{it} \ln \mathbf{P}_{it}$$

and where

$$S_{it} = \frac{\mathbf{P}_{it} Q_{it}}{C_t}$$

Differentiating (2) with respect to $\ln P_{it}$, one obtains:

$$\frac{\partial \ln C_t}{\partial \ln \mathbf{P}_{it}} = \frac{\partial \ln \mathbf{P}_t}{\partial \ln \mathbf{P}_{it}} + \frac{\partial \ln Q_t}{\partial \ln \mathbf{P}_t}\left(\frac{\partial \ln \mathbf{P}_t}{\partial \ln \mathbf{P}_{it}}\right) = (1+\beta) S_{it} \tag{3}$$

Modeling these cost shares, which is the second stage, is the focus of the next section.

The Linear Logit Model of Cost Shares

A common approach in deriving factor demand functions is to assume the existence of a twice continuously differentiable cost function either a log (TL) or square root (GL) quadratic and then apply the envelope theorem to derive a set of cost share equations or input/output equations, respectively. With linear parameter restrictions one can test for symmetry and linear homogeneity in prices.

Another approach is to approximate the cost share system directly with a logistic function, which ensures adding-up and the non-negativity of shares. Considine and Mount (1984){1} show how to impose zero degree homogeneity on a set of logistic cost share equations. Given the non-integrable nature of the model, however, Considine (1990){2} imposes symmetry locally -- either at a point with linear parameter restrictions or at each point in the sample using an iterative estimation procedure. In this study, symmetry at the mean cost shares is imposed to facilitate model simulation.

The unrestricted linear logit model of cost shares is as follows:

$$S_{it} = \frac{P_{it} Q_{it}}{C_t} = \frac{e^{f_{it}}}{\sum_{j=1}^{n} e^{f_{jt}}} \quad \forall\ i \tag{4}$$

where

$$f_{it} = \alpha_i + \sum_{j=1}^{n} \beta_{ij} \ln(\mathbf{P}_{jt}) + \gamma_i Q_t + \sum_{k=h,c} \delta_{ik} Z_{kt} + \tau T_t + \varepsilon_{it} \tag{5}$$

and

Q_t = quantity of fuel in period t,
P_{it} = price of fuel i in period t,
ε_{it} = random disturbance term, ~ $N(0,\sigma^2)$

and where α_i, β_{ij}, γ_i, δ_{ik} are unknown parameters. The inclusion of Q_t allows non-homothetic demand functions and the time trend permits nonneutral technical change. A normally distributed, random disturbance term with zero mean and constant variance is assumed. In the empirical analysis conducted below, the possibility of heteroscedasticity and autocorrelation in the disturbance terms is allowed.

By substituting (5) into (4), taking logarithms, and normalizing on the n^{th} cost share to eliminate the denominator in (4), the unrestricted log cost share equations are obtained:

$$\ln\left(\frac{S_{it}}{S_{nt}}\right) = (\alpha_i - \alpha_n) + \sum_{j=1}^{n} (\beta_{ij} - \beta_{nj})\ln(P_{jt}) + (\gamma_i - \gamma_n)Q_t + \sum_{k=h,c} (\delta_{ik} - \delta_{nk})Z_{kt} + (\tau_i - \tau_n)T_t + (\varepsilon_{it} - \varepsilon_{nt}) \quad \forall\, i=1,\ldots,n-1 \tag{6}$$

One could estimate these equations individually with ordinary least squares or together as a set of seemingly unrelated regressions. Notice that the dependent variables are in logarithms, which ensures non-negativity of the cost share predictions using (4), unlike the translog and generalized Leontief forms (see Considine, 1989a&b).{3,4} The normalizing constraints, $\alpha_n=\beta_{nh}=\gamma_i=\delta_{ik}=0$, identify the model. The parameter estimates are invariant with respect to this normalization (Considine and Mount, 1984){1}.

The unrestricted share elasticities with respect to prices derived by Considine and Mount (1984){1} are as follows:

$$\frac{\partial \ln S_{it}}{\partial \ln P_{kt}} = H_{ikt} = \beta_{ik} - \sum_{j=1}^{n} S_{jt}\beta_{jk} \tag{7}$$

Notice that the share elasticities are linear functions of the parameters and the cost shares. The share elasticities with respect to total quantity, weather, and technical change are also share weighted functions of the parameters, respectively.

The demand equations implicit in the LL model are zero degree homogeneous in prices when $\Sigma\beta_{ij}=d$, $\forall$ i, where d is some scalar. It is assumed that d = 0 without any loss of generality or invariance in the estimates. In this case the estimating equations take the following form:

$$\ln\left(\frac{S_{it}}{S_{nt}}\right) = (\alpha_i - \alpha_n) + \sum_{j=1}^{n-1} (\beta_{ij} - \beta_{nj})\ln\left(\frac{P_{it}}{P_{nt}}\right) + (\gamma_i - \gamma_n)Q_t + \sum_{k=h,c} (\delta_{ik} - \delta_{nk})Z_{kt} + (\tau_i - \tau_n)T_t + (\varepsilon_{it} - \varepsilon_{nt}) \quad \forall\, i=1,\ldots,n-1 \tag{8}$$

So relative prices are the regressors in the homogeneous LL model.

Linear combinations of the β_{ij} parameters in the LL model provide point estimates of Morishima elasticities of substitution, which are pure measures of substitution. Blackorby and Russell (1989){5} argue that Allen partial elasticities of substitution are uninformative recommending Morishima elasticities of substitution, which are:

$$\mu_{ijt} = -\frac{\partial \ln(Q_{it}/Q_{jt})}{\partial \ln(P_{it}/P_{jt})} \tag{9}$$

These elasticities in terms of logarithmic share derivatives are re-written as follows:

$$\mu_{ijt} = \frac{\partial \ln(S_{jt})}{\partial \ln(P_{it}/P_{jt})} - \frac{\partial \ln(S_{it})}{\partial \ln(P_{it}/P_{jt})} + 1. \tag{10}$$

Blackorby and Russell (1989){5} show that differentiating with respect to only one price in the Morishima elasticity rather than two as in the Allen partial elasticity of substitution maintains consistency with the ceteris paribus substitution experiment in moving along an isoquant. Applying (10) to (4) the following expression for the Morishima elasticities of substitution for the LL model is derived:

$$\mu_{ijt} = \frac{\partial f_{jt}}{\partial \ln(P_{it}/P_{jt})} - \frac{\partial f_{it}}{\partial \ln(P_{it}/P_{jt})} + 1, \ \forall\ i \neq j \neq n, \tag{11}$$

which for the homogeneous form given by (5) become:

$$\mu_{ijt} = \beta_{ji} - \beta_{ii} + 1, \quad i \neq j. \tag{12}$$

Hence, Morishima elasticities from a logistic cost share system are simple linear combinations of the price coefficients. Furthermore, these substitution elasticities are not equal as would be the case for the constant elasticity of substitution model with more than two inputs. This may seem an apparent contradiction of Uzawa's Impossibility Theorem, which states that it is not possible to generalize the constant elasticity of substitution model to more than two inputs. Constancy of the Morshima elasticities in the LL model, however, is possible because a differentiable cost function is not assumed (see Considine, 1990).{2} Hence, Uzawa's result does not apply to the logit cost share system. Obtaining a point estimate of substitution may be preferable to a variable one because confidence intervals for flexible functional forms can be very wide at extreme observations. Moreover, a symmetric, differentiable cost function is just an approximation with no inherent economic content.

Nevertheless, symmetry is important because it ensures that estimates of substitutability or complementarity between pairs of goods are the same across equations. Considine and Mount (1984){1} show that the symmetry constraints for the LL model are $S_i^*\beta_{ij}=S_j^*\beta_{ji}$, where the asterisk indicates the mean cost shares. Imposing these constraints on the homogenous cost share system given by (5) above, the following symmetric cost share model is obtained:

$$\begin{aligned}
\ln\left(\frac{S_{it}}{S_{nt}}\right) &= (\alpha_i-\alpha_n) \\
&-\left[\sum_{k=1}^{i-1} S_k^*\beta_{ki}^* - \sum_{k=i+1}^{n} S_k^*\beta_{ik}^* - S_i^*\beta_{in}^*\right]\ln\left(\frac{P_{it}}{P_{nt}}\right) \\
&+\sum_{k=1}^{i-1}(\beta_{ki}^*-\beta_{kn}^*)S_k^*\ln\left(\frac{P_{kt}}{P_{nt}}\right) \\
&+\sum_{k=i+1}^{n-1}(\beta_{ik}^*-\beta_{kn}^*)S_k^*\ln\left(\frac{P_{kt}}{P_{nt}}\right)+(\gamma_i-\gamma_n)\ln Q_t \\
&+\sum_{k=h,c}(\delta_{ik}-\delta_{nk})Z_{kt}-(\tau_i-\tau_n)T_t+(\varepsilon_{it}-\varepsilon_{nt})
\end{aligned} \qquad (13)$$

For this LL model, the Morishima elasticities are:

$$\mu_{ijt} = S_i^*(\beta_{ji}^* - \beta_{ii}^*) + 1, \quad i \neq j \qquad (14)$$

Again the Morishima elasticities are constant but in this case they are weighted by the mean cost shares. The cross price elasticities of demand, however, vary with cost shares and are:

$$E_{ikt} = S_{kt}^*\left(\beta_{ik}^* - \sum_{j=1}^{n} S_{jt}\beta_{jk}^*\right) + S_{kt}, \quad i \neq k. \qquad (15)$$

Similarly the own price elasticities of demand are:

$$E_{iit}=S_i^*\left(\beta_{ii}^*-\sum_{j=1}^{n} S_{jt}\beta_{ji}^*\right) + S_{it}-1, \ i=1,...n. \qquad (16)$$

The summation terms in (15) and (16) are zero at the symmetry point. Note that the cross price elasticities are asymmetric away from the symmetry point. The empirical models estimated below, however, do not display any contradictory estimates of substitution across equations.

Curvature Properties

If the concavity conditions hold at the point of symmetry, then the own price elasticities will remain negative for all predicted values of cost shares. The curvature of the demand equations implicit in any share system in terms of share elasticities are as follows:

$$\left(\frac{P_{it}P_{jt}}{C_t}\right)\left(\frac{\partial Q_{it}}{\partial P_{it}}\right) = S_{it}\left[S_{jt} + \frac{\partial \ln S_{it}}{\partial \ln P_{jt}} - \mu\right] \qquad (17)$$

where μ=1 when i=j and μ=0 otherwise. For the symmetric logit cost share model given by (6) and (13) the curvature conditions are:

$$\left(\frac{P_{it}P_{jt}}{C_t}\right)\left(\frac{\partial Q_{it}}{\partial P_{it}}\right) = S_{it}\left[S_{jt}+\left(\beta_{ij}^*-\sum_{k=1}^{n} S_{kt}\beta_{kj}^*\right)-\mu\right] \quad \forall i,j \qquad (18)$$

The continuity of the logistic share equations guarantees the existence of the price integrals and, thereby, justifies the use of Shephard's lemma. These demand derivatives expressed in matrix form are:

$$\Omega = (ss' - D)[I - \beta^* D^*] \qquad (19)$$

where s is a n x 1 vector of cost shares, D is a n x n diagonal matrix formed with the cost shares, β^* is a n x n matrix of the unknown parameters, and I is a n x n identity matrix. Concavity requires that Ω is negative semi-definite.

At the mean cost shares (19) becomes

$$\Omega^* = s^*s^{*'} - D^*[I - \beta^* D^*] \qquad (20)$$

because $s^* s^{*\prime} \beta^* D^* = 0$ assuming zero degree homogeneity in prices. Solving (20) for β^*:

$$\beta^* = (D^*)^{-1} \left[\Omega^* - s^* s^{*\prime} + D^*\right] (D^*)^{-1}. \tag{21}$$

Concavity requires Ω negative semi-definite, or

$$-x^{\prime}\Omega x \geq 0 \tag{22}$$

where x is some non-zero vector. Substituting (21) into (19) and the result into (22), one obtains:

$$-x^{\prime}\left\{(ss^{\prime}-D)\left[I-(D^*)^{-1}(\Omega^*-s^*s^{*\prime}+D^*)\right]\right\}x \geq 0 \tag{23}$$

Multiplying by x and factoring, (23) reduces to:

$$-xx^{\prime}\left\{(ss^{\prime}-D)(D^*)^{-1}\left[s^*s^{*\prime}-\Omega^*\right]\right\}x \geq 0 \tag{24}$$

The matrix $\mathbf{-xx'(ss'-D)(D^*)^{-1}}$ has full column rank and so its inverse exists. Multiplying by this inverse then simplifies (24) to showing:

$$x^{\prime}\left[s^*s^{*\prime} - \Omega^*\right] x \geq 0 \tag{25}$$

Given that cost shares are always positive in the LL model, if Ω^* is negative semi-definite, then the above inequality holds. Hence, if concavity holds at the symmetry point then it occurs for all cost shares.

Dynamic Adjustments

The response of energy demand to market shocks may occur over several periods. Accordingly, the following partial adjustment model is specified:

$$\ln Q_{it} - \ln Q_{it-1} = \lambda\left[\ln Q_{it}^* - \ln Q_{it-1}\right] \ \forall \mathbf{i}, \tag{26}$$

where Q_{it}^* is the equilibrium quantity, which for the above LL model is given by:

$$\ln Q_{it}^* = \ln C_t - \ln P_{it} + \left[f_{it} - \ln\left(\sum_{j=1}^{n} e^{f_{jt}}\right)\right]. \tag{27}$$

Substituting (27) into (26), normalizing upon the n^{th} fuel, and converting to shares:

$$\begin{aligned}\ln\left(\frac{S_{it}}{S_{nt}}\right) &= \lambda\,(f_{it}^* - f_{nt}^*) + (1-\lambda)\ln\left(\frac{P_{it}}{P_{nt}}\right) \\ &\quad + (1-\lambda)\ln\left(\frac{Q_{it-1}}{Q_{nt-1}}\right),\end{aligned} \tag{28}$$

where $(\mathbf{f_{it}^*-f_{nt}^*})$ are the equilibrium share functions. Hence, the dynamic version of the linear homogenous and symmetric model described above, is:

$$\begin{aligned}\ln\left(\frac{S_{it}}{S_{nt}}\right) &= (\alpha_i^* - \alpha_n^*) \\ &- \left[\sum_{k=1}^{i-1} S_k^*\beta_{ki}^* - \sum_{k=i+1}^{n} S_k^*\beta_{ik}^* - S_i^*\beta_{in}^*\right] \\ &\ln\left(\frac{P_{it}}{P_{nt}}\right) + \sum_{k=1}^{i-1}(\beta_{ki}^* - \beta_{kn}^*)S_k^*\ln\left(\frac{P_{kt}}{P_{nt}}\right) \\ &+ \sum_{k=i+1}^{n-1}(\beta_{ik}^* - \beta_{kn}^*)S_k^*\ln\left(\frac{P_{kt}}{P_{nt}}\right) \\ &+ (\gamma_i^* - \gamma_n^*)\ln Q_t + \sum_{k=h,c}(\delta_{ik}^* - \delta_{nk}^*)Z_{kt} \\ &+ (\tau_i^* - \tau_n^*)T_t + \lambda^*\ln\left(\frac{Q_{it-1}}{Q_{nt-1}}\right) \\ &+ (\varepsilon_{it}^* - \varepsilon_{nt}^*)\end{aligned} \tag{29}$$

where $\lambda^*=(1-\lambda)$ and the other parameters with asterisks signify multiplication by the adjustment parameter λ^*. The second term on the right of equation (29) drops out because d, the homogeneity scalar, is assumed zero. The four share systems estimated below take this basic form. More general partial adjustment mechanisms are possible but they involve substantially more parameters. Moreover, this parsimonious specification ensures that long-run elasticities are larger than short-run elasticities so long as the partial adjustment is between zero and one. This formulation provides a simple derivation of the long-run elasticities by dividing the short-run elasticities given by (15) and (16) by $(1-\lambda^*)$.

Demand Elasticity Estimates

Four sets of demand models for the residential, commercial, industrial, and electric utility sectors using the cost share equations (29) and the aggregate energy demand equation (1) are estimated. All models have monthly dummy variables to capture fixed seasonal effects. The simultaneity of prices and quantities and the invariance problem with cost share equations requires iterative instrumental variable estimation. Iterative three stage least squares does not provide consistent estimates when the instruments are not exogenous (see Cumby et. al (1983)).{6} In this case, the Generalized Method of Moments (GMM) estimator developed by Hansen (1982){7} and Hansen and Singleton (1982){8} provides consistent estimates. A first-order moving average error process using the techniques in Andrews (1990){9} is allowed for. The instrumental variables include lagged prices, quantities, income or output or employment appropriate to each sector, monthly dummies, heating and cooling degree days, and a time trend.

Initially, the maintained restrictions of the models, such as the partial adjustment process and the linear logit approximation of the cost share equations are tested. The value of the objective function for the GMM estimator is distributed as a Chi-squared statistic with degrees of freedom equal to the number instruments times the number of equations less the number of parameters. If the test statistic is less than the critical value then one cannot reject the models. As Table 19 below illustrates, one cannot reject the four models. Hence, the data supports the (LL) models of interfuel substitution. Moreover, the R^2 coefficients reflect an excellent fit although a more in-depth look at the forecasting performance of these models will be taken over the sample period with a mean squared error decomposition. With the exception of the total fuel demand equation in the electric utility sector, none of the equations display any detectable serial correlation.

It was found that weather effects were negligible in the industrial and electric utility sectors, failing to reject the hypothesis that the parameters are zero for these sectors. Hence, it is assumed below that industrial and electric utility fuel demands are unaffected by weather. Note that electric utility fuel demands respond to weather sensitive swings in residential and commercial electricity sales, which are highly responsive to variations in heating and cooling degree days. This feedback is illustrated with a model simulation below.

Table 19. Summary Fit Statistics and Tests of Overidentifying Restrictions

Dependent Variable	R^2	Durbin Watson	χ^2 Statistics Test	χ^2 Statistics Critical
Residential Sector			28.17	32.71
$\ln(S_{gt}/S_{et})$	0.99	2.50		
$\ln(S_{ht}/S_{et})$	0.99	2.12		
$\ln(Q_t^r)$	0.99	2.36		
Commercial Sector			21.99	25.02
$\ln(S_{gt}/S_{et})$	0.99	2.39		
$\ln(S_{ht}/S_{et})$	0.95	2.81		
$\ln(Q_t^c)$	0.98	1.77		
Electric Utility Sector			27.30	43.82
$\ln(S_{gt}/S_{ct})$	0.88	1.30		
$\ln(S_{ot}/S_{ct})$	0.88	1.25		
$\ln(Q_t^u)$	0.99	2.07		
Industrial Sector			67.63	77.99
$\ln(S_{gt}/S_{et})$	0.98	2.14		
$\ln(S_{dt}/S_{et})$	0.87	2.76		
$\ln(S_{rt}/S_{et})$	0.82	2.62		
$\ln(S_{ct}/S_{et})$	0.95	1.99		
$\ln(Q_t^i)$	0.92	2.11		

g = natural gas, h = heating fuel, e = electricity, c = steam coal, d = distillate fuel oil, r = residual fuel oil.

With confidence in the specification of the demand models, the interfuel substitution possibilities, with the Morishima elasticities discussed above, are examined. These elasticities are scale free measures of substitution possibilities measuring the proportionate rate of change in an input ratio for a percentage change in the corresponding price ratio. Blackorby and Russell prefer this elasticity because it correctly varies only one price in the ratio rather than both. As shown above, the Morishima elasticities in a linear logit model of cost shares are constant parameters, not variables as in flexible functional forms. Given this parametric feature, standard errors are by the distributional considerations implicit in variable share formulations.

The Morishima substitution elasticities and their standard errors appear in Table 20. The rows in this table are the prices and the columns are the input ratios. So, for instance, for a one percent change in the residential electricity to heating oil price, there is a 0.566 percent change in the ratio of electricity to heating oil use. Two main findings stand out. First, there is no significant complementarity between any two inputs across all four sectors. Second, short-run interfuel substitution elasticities are generally larger in the electric utility and industrial sectors than in the residential and commercial sectors. These results are consistent with engineering-economic studies demonstrating that small, dispersed fuel consumers, such as residential users, find it sub-optimal to have the fuel substitution capability of large industrial users.

Nevertheless, one finds significant substitution between heating oil and electricity in the residential sector, which may reflect the competition for new customers in the Northeastern U. S. where these fuels are currently dominant. Although a disaggregate regional analysis is needed, we capture regional diversity in fuel use through our aggregate indices of weather variation, which effectively weights regional degree-days by the number of gas and heating oil customers. The sample does not include the recent extension of natural gas pipelines to this region. The lack of any significant substitution involving natural gas may reflect the regional concentration of natural gas and heating oil consumption with gas used primarily in the Midwestern states and heating oil in the Northeast. Interfuel substitution possibilities are also small in the commercial sector, with the electricity-heating oil ratio showing a small but significant change with respect to commercial electricity prices.

In contrast, all substitution parameters in the electric utility sector are significantly different from zero (see Table 20). The comparative magnitudes of the elasticities suggest that natural gas and oil, which is primarily residual fuel and a minor amount of distillate fuel, are the strongest substitutes. Natural gas is also a substitute with steam coal in the electric utility sector. For gas price changes, that is looking across the gas row in the third panel of Table 20, there is slightly more competition from oil than from coal. Turned the other way, looking down the gas column, gas faces roughly equal opportunities from oil and coal price increases.

While still audible, the interfuel substitution signal is not as clear in the industrial sector. No significant substitution occurs from changing gas prices. Instead, industrial gas can be substituted quite strongly for residual fuel oil and coal as these prices change. Industry uses coal and residual oil to generate power and steam. In addition, they are increasingly using combined-cycle gas cogenerators, which have been the principal source of growth in gas consumption in the industrial sector. The results suggest that lower gas prices relative to coal and residual oil have, in part, induced these investments. Estimation results include significant substitution between all fuels as coal prices change. Electricity and residual fuel oil are significant substitutes as oil prices change. Finally, electricity price changes stimulate substitution between purchased electricity and coal, which may reflect the choice producers have between buying or generating their own power. In conclusion, the Morishima elasticities indicate that natural gas faces significant competition from residual fuel oil and coal in the industrial and electric utility sectors.

Since this model is not developed so as to include the equilibrium determination of energy consuming durable equipment and structures, dynamic adjustments modelled here reflect the lags in consumption decisions to price, weather, and income shocks. Hence, the short and intermediate-run elasticities assume a fixed capital stock. The estimated adjustment coefficients displayed below in Table 21 are relatively small, indicating that demands adjust rather quickly to market shocks. For instance, 50 percent of the total change in residential energy demand occurs in about two weeks with similar rates of adjustment in the other sectors. These results suggest that energy consumers assimilate market information relatively quickly.

Conventional price elasticities of demand appear in Table 22 for both the short and intermediate-run. Apart from steam coal in the industrial sector, all fuel demands are inelastic. The own price elasticities of demand are very small in the residential and commercial sectors. For instance, the short-run own price elasticity of residential demand for natural gas and electricity are both very inelastic. The short-run own price responsiveness of residential heating oil demand is substantially is greater at -0.22 but the commercial demand remains very inelastic.

The industrial demand for natural gas and electricity also are very price inelastic. In contrast, the own price elasticities of the industrial demand for distillate oil and residual fuel are substantially larger reflecting substitution with natural gas and steam coal. Industrial coal demand is the only fuel with an elastic demand curve primarily due to strong substitution with electricity. If the price of coal dropped, this result suggests an increase in coal consumption. However, in a broader context, a drop in coal prices could force electricity prices down as well, which would offset some of the increased coal use. The short-run own price elasticities for natural gas and oil in the electric

Table 20. Morishima Elasticities of Substitution (Standard Errors)

RESIDENTIAL SECTOR

	Natural Gas	Heating Oil	Electricity
Natural Gas	--	-0.192	0.117
	--	(0.174)	(0.218)
Heating Oil	0.163	--	0.257*
	(0.103)	--	(0.114)
Electricity	0.211	0.566**	--
	(0.233)	(0.216)	--

COMMERCIAL SECTOR

	Natural Gas	Heating Oil	Electricity
Natural Gas	--	0.015	0.086
	--	(0.119)	(0.097)
Heating Oil	0.119	--	0.143**
	(0.072)	--	(0.056)
Electricity	0.105	0.209	--
	(0.111)	(0.117)	--

ELECTRIC UTILITY SECTOR

	Natural Gas	Distillate & Residual Oil	Steam Coal
Natural Gas	--	0.403**	0.366**
	--	(0.112)	(0.087)
Distillate &	0.320**	--	0.289**
Residual Oil	(0.082)	--	(0.059)
Coal	0.333**	0.252**	--
	(0.075)	(0.039)	--

INDUSTRIAL SECTOR

	Natural Gas	Distillate Oil	Residual Oil	Steam Coal	Electricity
Natural Gas	--	-0.163	0.335	0.255	0.098
	--	(0.181)	(0.251)	(0.150)	(0.080)
Distillate Oil	0.308	--	0.705	0.627*	0.380
	(0.253)	--	(0.497)	(0.312)	(0.293)
Residual Oil	0.596*	0.861	--	0.375	0.539**
	(0.266)	(0.452)	--	(0.258)	(0.221)
Coal	1.652**	1.749**	--	1.557**	--
	(0.595)	(0.624)	(0.567)	--	--
Electricity	0.157	0.265	0.115	1.455**	--
	(0.091)	(0.264)	(0.206)	(0.559)	--

* Indicates significance at the 5% level and ** at the 1% level.

Table 21. Estimated Rates of Adjustment and Mean Lags

	Adjustment Coefficient (Standard Error)	Median Lag
Residential		
Cost Shares	0.235* (0.098)	0.478
Energy Demand	0.226* (0.083)	0.466
Commercial		
Cost Shares	0.606**	1.384
(0.057)		
Energy Demand	0.562** (0.068)	1.202
Electric Utilities		
Cost Shares	0.300** (0.044)	0.576
Industrial		
Cost Shares	0.321** (0.078)	0.610
Energy Demand	0.086 (0.125)	0.282

* Indicates significance at the 5% level and ** at the 1% level.

price elasticities for natural gas and oil in the electric utility sector are also substantial (see Table 22). However, the demand for coal in the electric utility sector is very price inelastic since changes in natural gas and oil prices induce only a small amount of fuel substitution.

The above elasticities assume that the level of total energy demand is constant in each sector. Net elasticities of demand allow the level of energy demand to change with individual fuel prices, output and income.

For instance, the net price elasticities of demand are:

$$\frac{\partial Q_i^{net}}{\partial P_i} = \left.\frac{\partial Q_i}{\partial P_i}\right|_{\bar{Q}} + \frac{\partial Q_i}{\partial Q}\frac{\partial Q}{\partial P}\frac{\partial P}{\partial P_i}$$

$$= \left.\frac{\partial \ln Q_i}{\partial \ln P_i}\right|_{\bar{Q}} + \frac{\partial \ln Q_i}{\partial \ln Q}\left(\frac{\partial \ln Q}{\partial \ln P}\right)\frac{\partial \ln P}{\partial \ln P_i} \qquad (30)$$

For this model, the first derivative in the second term in (30) is equal to the product of the inverse cost share and the last derivative in (30), which is approximately equal to the cost share, so the net price elasticity simplifies to:

$$\frac{\partial \ln Q_i^{net}}{\partial \ln P_i} = \left.\frac{\partial \ln Q_i}{\partial \ln P_i}\right|_{\bar{Q}} + S_i\beta \qquad (31)$$

The net income (output) elasticities are slightly more complex because they include indirect effects on the cost shares. The net income (output) elasticities are as follows:

$$\frac{\partial Q_i^{net}}{\partial Y} = \frac{C}{P_i}\frac{\partial S_i}{\partial Q}\frac{\partial Q}{\partial Y} + \frac{S_i}{P_i}\left(P\frac{\partial Q}{\partial Y} + Q\frac{\partial P}{\partial Y}\right) \qquad (32)$$

Assuming aggregate prices are unaffected by income or output, the net income (output) elasticities become:

$$\frac{\partial \ln Q_i^{net}}{\partial \ln Y} = \gamma\left\{1 + \frac{\partial \ln S_i}{\partial \ln Q}\right\}. \qquad (33)$$

Finally, the net weather elasticities are as follows:

$$\frac{\partial Q_i^{net}}{\partial Z_k} = \frac{C}{P_i}\frac{\partial S_i}{\partial Z_k} + \frac{S_i}{P_i}P\frac{\partial Q}{\partial Z_k} + \frac{C}{P_i}\frac{\partial S_i}{\partial Q}\frac{\partial Q}{\partial Z_k}, \qquad (34)$$

Table 22. Short and Intermediate-Run Price Elasticities of Demand

	RESIDENTIAL SECTOR		
	Natural Gas	Heating Oil	Electricity
Natural Gas	-0.074	-0.059	0.132
	(-0.096)	(-0.076)	(0.173)
Heating Oil	-0.267	-0.221	0.487
	(-0.347)	(-0.289)	(0.636)
Electricity	0.044	0.036	-0.079
	(-0.057)	(0.047)	(-0.104)
	COMMERCIAL SECTOR		
Natural Gas	-0.064	-0.013	0.077
	(-0.162)	(-0.032)	(0.195)
Heating Oil	-0.048	-0.123	0.180
	(-0.123)	(-0.335)	(0.458)
Electricity	0.018	0.011	-0.029
	(0.045)	(0.028)	(-0.073)

	ELECTRIC UTILITY SECTOR		
	Natural Gas	Distillate & Residual Oil	Steam Coal
Natural Gas	-0.298	0.056	0.241
	(-0.426)	(0.081)	(0.345)
Distillate &	0.105	-0.264	0.158
Residual Oil	(0.150)	(-0.377)	(0.227)
Coal	0.068	0.024	-0.092
	(0.097)	(0.034)	(-0.132)

	INDUSTRIAL SECTOR				
	Natural Gas	Distillate Oil	Residual Oil	Steam Coal	Electricity
Natural Gas	-0.074	-0.055	0.058	0.019	0.053
	(-0.109)	{-0.081)	(0.085)	(0.028)	(0.078)
Distillate Oil	-0.237	-0.364	0.323	0.116	0.161
	(-0.349)	(-0.536)	(0.476)	(0.171)	(0.237)
Residual Oil	0.261	0.342	-0.538	-0.076	0.011
	(0.385)	(0.503)	(-0.793)	(-0.112)	(0.017)
Coal	0.181	0.263	-0.163	-1.633	1.351
	(0.268)	(0.388)	(-0.240)	(-2.406)	(1.991)
Electricity	0.023	0.017	0.001	0.062	-0.104
	(0.035)	(0.025)	(0.002)	(0.092)	(-0.153)

Note: (Intermediate-Run elasticities).

which for the two-stage model is as follows:

$$\frac{\partial \ln Q_i^{net}}{\partial \ln Z_k} = \frac{\partial \ln S_i}{\partial \ln Z_k} + \upsilon_k \left\{ 1 + \frac{\partial \ln S_i}{\partial \ln Q} \right\}. \qquad (35)$$

The net elasticities of demand, which include the induced changes from the level of total sectoral energy demand, are presented in Table 23. For instance, oil price changes affect the level and mix of fuel demands. Overall, the own net price elasticities increase substantially from the price elasticities calculated holding the level of expenditures constant.

Income and output elasticities are also presented in (Table 23). The income elasticities for residential fuel demand are very small. The heating degree day elasticities are much larger with the heating oil and natural gas demand elasticities the most sensitive to colder weather. Residential electricity use increases with higher cooling degree days or warmer weather reflecting increased air conditioning demands. The commercial weather elasticities reflect somewhat less sensitivity to weather. Commercial employment, fossil fuel generation, and industrial production are used as demand shifters in the other three sectors. The commercial employment elasticities range from 0.466 for natural gas to 0.192 for heating oil. Gas and coal use in the electric utility sector rise slightly less than proportionately with electric generation. In contrast, oil use rises sharply with higher generation perhaps reflecting peak load generation. Except for residual oil, all fuel demands rise with higher industrial production.

Within Sample Model Forecasting Performance

Next, the forecasting performance of the model within the sample is evaluated. The simulation model includes (1) and (29) for each sector, energy demand identities and divisia price indices, which are functions of the predicted shares from (4). The performance of these simulation models is checked by conducting a static simulation within the sample period and comparing the actual and predicted values using the root mean squared error and its decomposition. An overview of the model's performance appears in Table 25, which reports the errors in predicting total fuel demands. The results for natural gas, electricity, and coal indicate an excellent fit with root mean squared errors in the 1-2 percent range with negligible bias. The errors in distillate and residual fuel demand are substantially higher, although there appears very little bias in the forecasts. Tables 25 and 26 provide the sector level detail of these errors. The errors in predicting oil consumption are relatively large across all four sectors. Perhaps if data on stocks held by all consumers were available, energy demand models with inventories would provide more accurate forecasts.

Out-of-Sample Forecasting Performance

Next, the demand models are assembled into one simulation for out-of-sample forecasting and model simulation. In Table 26, the forecasts of total fuel demands are compared with the recent fourth quarter forecasts from the Energy Information Administration (EIA). Except for residual fuel oil, the forecasts show no discernible divergence from the (EIA). forecasts.

Conclusions

All functional forms used in applied demand analysis involve trade-offs. It can be argued that the linear logit model of cost shares offers considerable advantages over flexible functional forms in maintaining non-negativity and desirable curvature properties in return for only being able to impose symmetry at a point. This paper demonstrates that the linear logit model of cost shares can provide consistent and very intuitively appealing estimates of short-run interfuel substitution. Not surprisingly, very limited substitution possibilities are found between fuels in the residential and commercial sectors but considerably greater substitution in the industrial and electric utility sectors. Moreover, the model simulations demonstrate a superior fit over the sample period, stable projections out of sample, and sensible responses in fuel demands to weather, income, and output shocks.

There are several avenues for further research. The mean square errors on oil consumption across sectors may reflect underlying data problems. Therefore, analysis of the consistency of the oil data sample may be worthwhile.

Secondly, long-run adjustment through technical changes in capital stocks deserves further study. One could calibrate these adjustments to EIA’s annual energy demand models via an error correction process.

Table 23. Net Short-Run Price and Income, Output, and Weather Elasticities

	RESIDENTIAL SECTOR					
				Personal	Degree-Days	
	Natural Gas	Heating Oil	Electricity	Income	Heating	Cooling
Natural Gas	-0.162	-0.148	0.043	0.124	0.608	-0.037
Heating Oil	-0.285	-0.241	0.467	0.108	0.745	-0.074
Electricity	-0.224	-0.232	-0.347	0.138	0.209	0.141

	COMMERCIAL SECTOR					
					Degree-Days	
	Natural Gas	Heating Oil	Electricity	Employment	Heating	Cooling
Natural Gas	-0.071	-0.020	0.070	0.466	0.239	0.013
Heating Oil	-0.050	-0.134	0.179	0.192	0.207	0.055
Electricity	-0.012	-0.019	-0.058	0.341	0.053	0.043

	ELECTRIC UTILITY SECTOR			
	Natural Gas	Distillate & Residual	Steam Coal	Fossil Fuel Generation
Natural Gas	-0.331	0.022	0.207	0.783
Dist. & Resid.	0.087	-0.282	0.140	4.098
Coal	-0.051	-0.096	-0.212	0.859

	INDUSTRIAL SECTOR					
	Natural Gas	Distillate Oil	Residual Oil	Steam Coal	Electricity	Output
Natural Gas	-0.136	-0.118	-0.005	-0.044	-0.010	0.481
Distillate Oil	-0.251	-0.378	0.309	0.102	0.147	1.637
Residual Oil	0.247	0.328	-0.552	-0.090	-0.002	-0.329
Coal	0.012	0.110	-0.082	-1.640	1.345	0.039
Electricity	-0.087	0.021	-0.128	1.212	-0.244	0.221

Table 24. Mean Squared Error Decomposition for Total Fuel Demands from Static Simulation over the Sample Period

	Root Mean	Mean Squared Error Decomposition		
	Square Errors	Bias	Regression	Disturbance
Total Fuel Demands				
Electricity	0.016	0.000	0.000	1.000
Natural Gas	0.021	0.004	0.012	0.985
Distillate oil	0.040	0.001	0.057	0.942
Residual Fuel	0.092	0.007	0.006	0.987
Steam Coal	0.015	0.003	0.090	0.907

g = natural gas, h = heating fuel, e = electricity, c = steam coal, d = distillate fuel oil, r = residual fuel oil.

Table 25. Mean Squared Error Decomposition by Sector from Static Simulation over the Sample Period

	Root Mean Square Error	Mean Squared Error Decomposition Bias	Regression	Disturbance
Residential				
$\ln(S_{gt}/S_{et})$	0.032	0.000	0.004	0.996
$\ln(S_{ht}/S_{et})$	0.024	0.000	0.001	0.999
$\ln(Q_t^r)$	0.003	0.007	0.000	0.999
S_{gt}	0.019	0.000	0.000	1.000
S_{ht}	0.098	0.002	0.000	0.998
S_{et}	0.007	0.001	0.000	0.998
P_t^r	0.000	0.312	0.004	0.684
Q_{gt}	0.027	0.000	0.000	1.000
Q_{ht}	0.089	0.001	0.001	0.998
Q_{et}	0.022	0.000	0.000	1.000
Commercial				
$\ln(S_{gt}/S_{et})$	0.024	0.007	0.000	0.993
$\ln(Sht/S_{et})$	0.025	0.002	0.003	0.999
$\ln(Q_t^c)$	0.002	0.000	0.002	0.999
S_{gt}	0.024	0.000	0.001	0.998
S_{ht}	0.068	0.000	0.000	1.000
S_{et}	0.007	0.006	0.000	0.994
P_t^c	0.000	0.125	0.040	0.834
Q_{gt}	0.031	0.000	0.004	0.997
Q_{ht}	0.069	0.000	0.000	0.995
Q_{et}	0.010	0.001	0.003	0.996
Electric Utilities				
$\ln(S_{gt}/S_{ct})$	0.052	0.019	0.005	0.976
$\ln(S_{ot}/S_{ct})$	0.062	0.015	0.085	0.900
$\ln(Q_t^u)$	0.004	0.000	0.021	0.979
S_{gt}	0.058	0.031	0.023	0.946
S_{ot}	0.112	0.003	0.069	0.928
S_{ct}	0.016	0.005	0.002	0.997
P_t^u	0.000	0.060	0.057	0.883
Q_{gt}	0.060	0.022	0.007	0.971
Q_{ot}	0.140	0.002	0.062	0.936
Q_{ct}	0.018	0.003	0.088	0.909
Industrial				
$\ln(S_{gt}/S_{et})$	0.035	0.003	0.001	0.996
$\ln(S_{dt}/S_{et})$	0.104	0.015	0.082	0.901
$\ln(S_{rt}/S_{et})$	0.047	0.006	0.130	0.863
$\ln(S_{ct}/S_{et})$	0.008	0.000	0.004	0.996
$\ln(Q_t^i)$	0.004	0.006	0.002	0.993
S_{gt}	0.022	0.000	0.000	0.999
S_{dt}	0.325	0.013	0.183	0.803
S_{rt}	0.108	0.003	0.189	0.808
S_{ct}	0.032	0.000	0.004	0.999
S_{et}	0.018	0.002	0.033	0.967
P_t^i	0.002	0.075	0.053	0.872
Q_{gt}	0.027	0.001	0.005	0.994
Q_{dt}	0.316	0.013	0.113	0.875
Q_{rt}	0.116	0.000	0.062	0.937
Q_{ct}	0.023	0.001	0.000	0.998
Q_{et}	0.010	0.011	0.003	0.986

g = natural gas, h = heating fuel, e = electricity, c = steam coal, d = distillate fuel oil,r = residual fuel oil.

Table 26. Dynamic Simulation from December 1994 to December 1995: Percent Changes from Fourth Quarter 1994 EIA Forecast

	Natural Gas	Distillate Oil	Residual Oil	Steam Coal	Electricity
Dec.93	3.79	2.55	2.96	14.08	4.71
Jan.94	3.09	2.52	1.23	14.50	4.38
Feb.94	3.19	0.07	2.03	3.49	2.52
Mar.94	3.98	3.73	2.12	32.47	2.99
Apr.94	5.39	4.84	-1.05	4.46	4.54
May.94	3.98	4.76	0.24	-5.11	1.37
June.94	3.26	0.20	1.14	21.24	2.87
July.94	-1.12	-4.69	-1.28	21.36	-2.33
Aug.94	-0.52	-2.46	-0.35	10.31	-1.85
Sept.94	2.45	-0.21	1.87	8.76	0.31
Oct.94	-3.02	-1.17	5.36	-10.96	-6.24
Nov.94	-1.12	2.70	6.04	-14.37	-3.95
Dec.94	0.59	5.05	5.31	-5.96	-1.10
Jan.95	3.11	7.24	1.79	-5.31	2.69
Feb.95	3.41	5.05	3.35	7.87	1.12
Mar.95	-3.57	-1.16	4.29	-5.67	-6.91
Apr.95	-1.70	-1.97	0.18	-10.96	-5.38
May.95	-3.58	-4.91	-0.72	-16.77	-7.83
June.95	2.88	-2.86	-0.19	-4.04	1.08
July.95	2.92	-3.56	-1.54	-9.21	1.30
Aug.95	2.36	-2.63	-0.50	-12.06	0.21
Sept.95	3.93	-1.53	-0.15	-13.64	1.32
Oct.95	-1.74	-2.67	2.74	-13.03	-5.65
Nov.95	0.05	1.57	3.46	-16.27	-3.63
Dec.95	1.71	4.29	2.80	-10.07	-1.29

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Figure References

The following is a list of references for the figures appearing in this issue of the *Annual Supplement*. Except where noted, all data for figures are taken from datasets containing monthly values of each variable depicted, aggregated to quarterly or annual values as required using appropriate weights. In Figures 4 through 8, the "One-Year-Ahead Forecast Percent Error" is determined by subtracting the "One-Year-Ahead" actual value of the variable from the forecasted value then dividing that result by the actual value. Also, except when noted, all figures refer to the base case.

1. Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(95/02) (Washington DC, February 1995), Table 4.

2. Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(95/02) (Washington, DC, February 1995), Table 31.

3. **History:** Compiled from monthly data for the refiner acquisition cost of imported crude oil used in publication of Energy Information Administration, *Historical Monthly Energy Review, 1973-1988*, DOE/EIA-0035(78), Table 9.1; for recent values, *Petroleum Marketing Monthly*, DOE/EIA-0380, Table 1. **Projections:** Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 85/1Q through 93/4Q base (mid-price) case. Table 2, "Macroeconomic, Oil Price, and Weather Assumptions" for projections for the first quarter 1986 through the third quarter 1991; Table 5, "Energy Prices" for projections for the fourth quarter 1991 through the fourth quarter 1994.

4. **History:** Compiled from monthly data for the residential electricity prices used in publication of Energy Information Administration, *Historical Monthly Energy Review, 1973-1988*, DOE/EIA-0035(78), Table 9.9; for recent values, *Monthly Energy Review*, DOE/EIA-0035, Table 9.9. **Projections:** Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 85/1Q through 93/4Q base (mid-price) case, Table 5, "Energy Prices."

5. **History:** Compiled from monthly data used in publication of Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109, Table S1, adjusted in years prior to 1993 for new (1993) reporting basis for fuel ethanol blended into motor gasoline (See *Short-Term Energy Outlook*, DOE/EIA-0202(93/3Q), Appendix B). **Projections:** Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 85/1Q through 93/4Q base (mid-price) case. Table: "U.S. Petroleum Supply and Demand: Mid-World Oil Price Case."

6. **History:** Compiled from monthly data used in publication of Energy Information Administration, *Natural Gas Annual, Volume 2*, DOE/EIA-0131, Table 3 for historical series; for recent values, Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130. **Projections:** Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 85/1Q through 93/4Q base (mid price) case. Table: "U.S. Natural Gas Supply and Demand: Mid-World Oil Price Case."

7. **History:** Compiled from quarterly data used in publication of Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121, Table 1. **Projections:** Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 85/1Q through 93/4Q base (mid-price) case. Table: "U.S. Coal Supply and Demand: Mid-World Oil Price Case."

8. **History:** Compiled from monthly data used in publication of Energy Information Administration, *Electric Power Monthly* , DOE/EIA-0226, Table 51. **Projections:** Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 85/1Q through 93/4Q base (mid-price) case. Table: "U.S. Electricity Supply and Demand: Mid-World Oil Price Case."

Appendix A

Regression Results
(Chapter 2)

Table A1. Liquefied Petroleum Gas (LPG) Refinery Output (LGROPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LGROPUS	20	124	0.08439	0.0006806	0.02609	0.9601	0.9539	1.739

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
LGRO_B0	-0.20452	0.10739	-1.90	0.0592	LGROPUS constant coefficient
LGRO_R1	0.04006	0.01430	2.80	0.0059	LGROPUS coef of RVPI
LGRO_R2	0.09819	0.01498	6.55	0.0001	LGROPUS coef of RVPII
LGRO_MG	-0.06122	0.02489	-2.46	0.0153	LGROPUS coef of MGROPUS
LGRO_C1	0.06312	0.01395	4.53	0.0001	LGROPUS coef of CORIPUS
LGRO_C2	0.07689	0.02063	3.73	0.0003	LGROPUS coef of UORIPUS
LGRO_C3	-0.05394	0.04293	-1.26	0.2114	LGROPUS coef of PSRIPUS
LGRO_T	0.00109	0.00025	4.42	0.0001	LGROPUS coef of TIME
LGRO_E1	0.02550	0.01040	2.45	0.0156	LGROPUS coef of JAN
LGRO_E2	0.05720	0.01305	4.38	0.0001	LGROPUS coef of FEB
LGRO_E3	0.12045	0.01488	8.10	0.0001	LGROPUS coef of MAR
LGRO_E4	0.10428	0.01504	6.93	0.0001	LGROPUS coef of APR
LGRO_E5	0.09845	0.01564	6.29	0.0001	LGROPUS coef of MAY
LGRO_E6	0.09400	0.01598	5.88	0.0001	LGROPUS coef of JUN
LGRO_E7	0.09576	0.01588	6.03	0.0001	LGROPUS coef of JUL
LGRO_E8	0.08076	0.01548	5.22	0.0001	LGROPUS coef of AUG
LGRO_E9	0.06150	0.01347	4.57	0.0001	LGROPUS coef of SEP
LGRO_E10	0.03735	0.01220	3.06	0.0027	LGROPUS coef of OCT
LGRO_E11	-0.00062	0.00838	-0.07	0.9410	LGROPUS coef of NOV
LGRO_L1	0.72092	0.06490	11.11	0.0001	LGROPUS 1st-order autocorrelation coefficient

Method of Estimation: OLS regression with 1st-order autocorrelation correction
RANGE of Fit: 8301 TO 9412

CORIPUS = Refinery input of crude oil, million barrels per day
LGROPUS = Refinery output of liquefied petroleum gas, million barrels per day
MGROPUS = Refinery output of finished motor gasoline, million barrels per day
PSRIPUS = Refinery inputs of "other" petroleum products, million barrels per day
RVPI = Dummy variable = 1 if Month = April through August and Year = 1989 through 1991; 0 otherwise
RVPII = Dummy variable = 1 if Month = April through August and Year > 1989; 0 otherwise
TIME = Integers 1 -> n, where n = number of observations
UORIPUS = Refinery input of unfinished oils, million barrels per day
JAN -> NOV = Monthly dummy variables

Table A2. Liquefied Petroleum Gas (LPG) Refinery Inputs (LGRIPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
LGRIPUS	16	152	0.04843	0.0003186	0.01785	0.9414	0.9356	1.676

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
LGRI_B0	0.09699	0.05447	1.78	0.0769	LGROPUS constant coefficient
LGRI_R1	-0.01379	0.00902	-1.53	0.1287	LGROPUS coef of RVPI
LGRI_R2	-0.00752	0.00902	-0.83	0.4059	LGROPUS coef of RVPII
LGRI_MG	0.04541	0.00775	5.86	0.0001	LGROPUS coef of MGROPUS
LGRI_E1	-0.02123	0.00592	-3.59	0.0004	LGROPUS coef of JAN
LGRI_E2	-0.06542	0.00776	-8.43	0.0001	LGROPUS coef of FEB
LGRI_E3	-0.13191	0.00862	-15.30	0.0001	LGROPUS coef of MAR
LGRI_E4	-0.15314	0.00904	-16.94	0.0001	LGROPUS coef of APR
LGRI_E5	-0.16089	0.00893	-18.02	0.0001	LGROPUS coef of MAY
LGRI_E6	-0.16764	0.00884	-18.97	0.0001	LGROPUS coef of JUN
LGRI_E7	-0.17298	0.00876	-19.75	0.0001	LGROPUS coef of JUL
LGRI_E8	-0.16016	0.00855	-18.73	0.0001	LGROPUS coef of AUG
LGRI_E9	-0.12521	0.00750	-16.69	0.0001	LGROPUS coef of SEP
LGRI_E10	-0.07112	0.00698	-10.19	0.0001	LGROPUS coef of OCT
LGRI_E11	-0.01024	0.00517	-1.98	0.0001	LGROPUS coef of NOV
LGRI_L1	0.67622	0.06309	10.72	0.0001	LGROPUS 1st-order autocorrelation coefficient

Method of Estimation: OLS regression with 1st-order autocorrelation correction
RANGE of Fit: 8301 TO 9412

LGRIPUS = Refinery inputs of liquefied petroleum gas, million barrels per day
MGROPUS = Refinery output of finished motor gasoline, million barrels per day
RVPI = Dummy variable = 1 if Month = April through August and Year = 1989 through 1991; 0 otherwise
RVPII = Dummy variable = 1 if Month = April through August and Year > 1989; 0 otherwise
JAN -> NOV = Monthly dummy variables

Table A3. Finished Motor Gasoline Refinery Output (MGROPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
MGROPUS	23	121	0.62206	0.0051410	0.07170	0.9710	0.9657	1.841

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
MGRO_B0	-0.05528	0.52566	-0.11	0.9164	MGROPUS constant coefficient
MGRO_C1	0.42554	0.02509	16.96	0.0001	MGROPUS coef of CORIPUS
MGRO_C2	0.54363	0.05148	10.56	0.0001	MGROPUS coef of UORIPUS
MGRO_C3	0.65543	0.11625	5.64	0.0001	MGROPUS coef of (PSRIPUS - OXRIPUS)
MGRO_C4	1.43754	0.23727	6.06	0.0001	MGROPUS coef of OXRIPUS
MGRO_C5	0.86889	0.15428	5.63	0.0001	MGROPUS coef of (LGRIPUS - LGROPUS)
MGRO_C6	1.32905	0.55575	2.39	0.0001	MGROPUS coef of PPRIPUS
MGRO_PR	0.63892	0.11656	5.48	0.0001	MGROPUS coef of MGWHUUSX/D2WHUUS
MGRO_PS	0.00046	0.00138	0.33	0.7393	MGROPUS coef of lag(MGPSPUSA)
MGRO_D8404	0.11727	0.06349	1.85	0.0672	MGROPUS coef of D8404
MGRO_D8406	-0.15247	0.06698	-2.28	0.0246	MGROPUS coef of D8406
MGRO_E1	0.00150	0.03192	0.05	0.9625	MGROPUS coef of JAN
MGRO_E2	0.00946	0.04305	0.22	0.8264	MGROPUS coef of FEB
MGRO_E3	0.04845	0.05955	0.81	0.4175	MGROPUS coef of MAR
MGRO_E4	0.11111	0.06047	1.84	0.0686	MGROPUS coef of APR
MGRO_E5	0.11271	0.05996	1.88	0.0626	MGROPUS coef of MAY
MGRO_E6	0.10389	0.06158	1.69	0.0942	MGROPUS coef of JUN
MGRO_E7	0.08716	0.06119	1.42	0.1569	MGROPUS coef of JUL
MGRO_E8	0.06312	0.05911	1.07	0.2878	MGROPUS coef of AUG
MGRO_E9	0.02129	0.04816	0.44	0.6593	MGROPUS coef of SEP
MGRO_E10	-0.09721	0.03912	-2.48	0.0143	MGROPUS coef of OCT
MGRO_E11	-0.04096	0.02571	-1.59	0.1137	MGROPUS coef of NOV
MGRO_L1	0.65332	0.08027	8.14	0.0001	MGROPUS 1st-order autocorrelation coefficient

Method of Estimation: OLS regression with 1st-order autocorrelation correction
RANGE of Fit: 8301 TO 9412

CORIPUS = Refinery inputs of crude oil, million barrels per day
D2WHUUS = Wholesale price of motor gasoline, cents per gallon
LGRIPUS = Refinery inputs of liquefied petroleum gases, million barrels per day
LGROPUS = Refinery outputs of liquefied petroleum gases, million barrels per day
MGPSPUSA = Finished motor gasoline end-of month stocks (deseasonalized), million barrels
MGROPUS = Refinery production of finished motor gasoline, million barrels per day
MGWHUUSX = Wholesale price of motor gasoline, cents per gallon
OXRIPUS = Refinery inputs of oxygenates, million barrels per day
PPRIPUS = Refinery inputs of pentanes plus, million barrels per day
PSRIPUS = Refinery inputs of "other" petroleum products, million barrels per day
UORIPUS = Refinery inputs of unfinished oils, million barrels per day
D8404 = Dummy variable = 1 if Month = April and Year = 1984; 0 otherwise
D8406 = Dummy variable = 1 if Month = June and Year = 1984; 0 otherwise
JAN -> NOV = Monthly dummy variables

Table A4. Crude Oil Refinery Inputs (CORIPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
CORIPUS	28	128	5.22295	0.04080	0.20200	0.9528	0.9428	1.966

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
CORI_B0	9.05960	1.69073	5.36	0.0001	CORIPUS constant coefficient
CORI_R1	-0.07433	0.10886	-0.68	0.4960	CORIPUS coef of RVPI
CORI_R2	0.01690	0.12534	0.13	0.8929	CORIPUS coef of RVPII
CORi_PSRI	-0.89148	0.31279	-2.85	0.0051	CORIPUS coef of (PSRIPUS - OXRIPUS)
CORI_OXRI	0.52744	0.65402	0.81	0.4215	CORIPUS coef of OXRIPUS
CORI_UORI	-0.19189	0.14014	-1.37	0.1733	CORIPUS coef of UORIPUS
CORI_LGRI	-1.12122	0.43319	-2.59	0.0108	CORIPUS coef of (LGRIPUS - LGROPUS)
CORI_PATC	0.16877	0.04263	3.96	0.0001	CORIPUS coef of PATCPUS
CORI_PAT1	0.15926	0.05355	2.97	0.0035	CORIPUS coef of lag(PATCPUS)
CORI_PAT2	0.09687	0.04614	2.10	0.0377	CORIPUS coef of lag2(PATCPUS)
CORI_PAT3	0.10210	0.04255	2.40	0.0179	CORIPUS coef of lag3(PATCPUS)
CORI_MGPS	-0.01329	0.00405	-3.28	0.0013	CORIPUS coef of lag(MGPSPUSA)
CORI_MGP1	-0.00796	0.00383	-2.08	0.0397	CORIPUS coef of lag2(MGPSPUSA)
CORI_DFPS	-0.00351	0.00402	-0.87	0.3839	CORIPUS coef of lag(DFPSPUSA)
CORI_DFP1	-0.00689	0.00390	-1.77	0.0794	CORIPUS coef of lag2(DFPSPUSA)
CORI_D8311	0.41254	0.19103	2.16	0.0327	CORIPUS coef of D8311
CORI_E2	-0.28326	0.08365	-3.39	0.0009	CORIPUS coef of FEB
CORI_E3	-0.36690	0.13520	-2.71	0.0076	CORIPUS coef of MAR
CORI_E4	0.03692	0.14778	0.25	0.8031	CORIPUS coef of APR
CORI_E5	0.40274	0.15403	2.61	0.0100	CORIPUS coef of MAY
CORI_E6	0.72762	0.15504	4.69	0.0001	CORIPUS coef of JUN
CORI_E7	0.69659	0.14803	4.71	0.0001	CORIPUS coef of JUL
CORI_E8	0.59114	0.13832	4.27	0.0001	CORIPUS coef of AUG
CORI_E9	0.53612	0.11960	4.48	0.0001	CORIPUS coef of SEP
CORI_E10	0.28572	0.10641	2.68	0.0082	CORIPUS coef of OCT
CORI_E11	0.46361	0.09199	5.04	0.0001	CORIPUS coef of NOV
CORI_E12	0.37286	0.09140	4.08	0.0001	CORIPUS coef of DEC
CORI_L1	0.57415	0.08531	6.73	0.0001	CORIPUS 1st-order autocorrelation coefficient

Method of Estimation: OLS regression with 1st-order autocorrelation correction
RANGE of Fit: 8301 TO 9412

CORIPUS = Refinery inputs of crude oil, million barrels per day
DFPSPUSA = Distillate fuel end-of month stocks (deseasonalized), million barrels
LGRIPUS = Refinery inputs of Liquefied Petroleum Gases, million barrels per day
LGROPUS = Refinery outputs of Liquefied Petroleum Gases, million barrels per day
MGPSPUSA = Finished motor gasoline end-of month stocks (deseasonalized), million barrels
OXRIPUS = Refinery inputs of oxygenates, million barrels per day
PATCPUS = Total demand for petroleum products, million barrels per day
PSRIPUS = Refinery inputs of "other" petroleum products, million barrels per day
UORIPUS = Refinery inputs of unfinished oils, million barrels per day
RVPI = Dummy variable = 1 if Month = April through August and Year = 1989 through 1991; 0 otherwise
RVPII = Dummy variable = 1 if Month = April through August and Year > 1989; 0 otherwise
D8311 = Dummy variable = 1 if Month = November and Year = 1983; 0 otherwise
FEB -> DEC = Monthly dummy variables

Appendix B

Detailed Forecast Error Tables

Table B1. Refiner Acquisition Cost of Imported Crude Oil, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(dollars per barrel)						
93/3Q	18.00	19.00	18.00	18.00	19.00	20.00	3.44
93/4Q	--	17.50	17.25	16.50	17.00	18.00	2.09
94/1Q	--	--	15.00	15.00	15.50	16.00	1.05
94/2Q	--	--	--	13.50	14.00	15.00	2.06
94/3Q	--	--	--	--	16.00	16.50	0.54
94/4Q	--	--	--	--	--	16.50	0.34
Actual	**15.60**	**14.09**	**13.01**	**15.80**	**16.73**	**16.16**	
Average Absolute Error	2.40	4.16	3.74	1.50	1.45	1.28	2.04
	(percent error)						
93/3Q	15.4	34.8	38.4	13.9	13.6	23.8	22.6
93/4Q	--	24.2	32.6	4.4	1.6	11.4	13.8
94/1Q	--	--	15.3	-5.1	-7.4	-1.0	6.8
94/2Q	--	--	--	-14.6	-16.3	-7.2	12.7
94/3Q	--	--	--	--	-4.4	2.1	3.3
94/4Q	--	--	--	--	--	2.1	2.1
Average Absolute Percent Error	15.4	29.5	28.7	9.5	8.6	7.9	13.8

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B2. Retail Motor Gasoline Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(dollars per gallon)						
93/3Q	1.21	1.22	1.19	1.24	1.25	1.26	0.06
93/4Q	--	1.21	1.21	1.24	1.25	1.25	0.06
94/1Q	--	--	1.15	1.21	1.22	1.21	0.03
94/2Q	--	--	--	1.16	1.17	1.18	0.03
94/3Q	--	--	--	--	1.20	1.22	0.02
94/4Q	--	--	--	--	--	1.24	0.03
Actual	**1.16**	**1.17**	**1.11**	**1.15**	**1.23**	**1.21**	
Average Absolute Error	0.05	0.05	0.07	0.06	0.03	0.03	0.04
	(percent error)						
93/3Q	4.3	4.3	7.2	7.8	1.6	4.1	4.8
93/4Q	--	3.4	9.0	7.8	1.6	3.3	4.9
94/1Q	--	--	3.6	5.2	-0.8	0.0	2.3
94/2Q	--	--	--	0.9	-4.9	-2.5	2.8
94/3Q	--	--	--	--	-2.4	0.8	1.6
94/4Q	--	--	--	--	--	2.5	2.5
Average Absolute Percent Error	4.3	3.8	6.6	5.4	2.3	2.2	3.7

-- = Not applicable.

Note: Gasoline Prices are an average of all grades and services, including taxes.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B3. Residential Heating Oil Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(dollars per gallon)						
93/3Q	0.89	0.97	0.99	0.93	0.92	1.01	0.09
93/4Q	--	0.95	0.95	0.91	0.92	0.98	0.07
94/1Q	--	--	0.88	0.87	0.93	0.93	0.05
94/2Q	--	--	--	0.88	0.86	0.91	0.03
94/3Q	--	--	--	--	0.84	0.92	0.04
94/4Q	--	--	--	--	--	0.90	0.05
Actual	**0.85**	**0.88**	**0.91**	**0.87**	**0.83**	**0.85**	
Average Absolute Error	0.04	0.08	0.05	0.03	0.06	0.09	0.06
	(percent error)						
93/3Q	4.7	10.2	8.8	6.9	10.8	18.8	10.0
93/4Q	--	8.0	4.4	4.6	10.8	15.3	8.5
94/1Q	--	--	-3.3	0.0	12.0	9.4	6.1
94/2Q	--	--	--	1.1	3.6	7.1	3.9
94/3Q	--	--	--	--	1.2	8.2	4.8
94/4Q	--	--	--	--	--	5.9	5.9
Average Absolute Percent Error	4.7	9.1	5.5	3.2	7.7	10.8	7.4

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B4. Residual Fuel Oil Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(dollars per barrel)						
93/3Q	14.53	16.10	15.84	14.82	15.33	16.99	1.43
93/4Q	--	15.73	15.82	13.98	14.22	15.80	1.25
94/1Q	--	--	12.89	11.81	12.19	13.54	2.34
94/2Q	--	--	--	12.00	12.20	13.64	2.53
94/3Q	--	--	--	--	12.80	14.02	2.38
94/4Q	--	--	--	--	--	14.49	1.26
Actual	**13.52**	**12.70**	**14.38**	**13.84**	**15.83**	**15.75**	
Average Absolute Error	1.01	3.22	1.46	1.25	2.48	1.43	1.80
	(percent error)						
93/3Q	7.5	26.8	10.2	7.1	-3.2	7.9	10.0
93/4Q	--	23.9	10.0	1.0	-10.2	0.3	8.6
94/1Q	--	--	-10.4	-14.7	-23.0	-14.0	15.7
94/2Q	--	--	--	-13.3	-22.9	-13.4	16.7
94/3Q	--	--	--	--	-19.1	-11.0	15.1
94/4Q	--	--	--	--	--	-8.0	8.0
Average Absolute Percent Error	7.5	25.3	10.2	9.0	15.7	9.1	12.3

-- = Not applicable.
Note: Prices are refiner retail sales, average of all sulfur contents.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B5. Natural Gas Wellhead Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
	(dollars per thousand cubic feet)						
93/3Q	1.98	2.29	2.33	2.03	2.19	2.53	0.35
93/4Q	--	2.35	2.36	2.02	2.15	2.49	0.40
94/1Q	--	--	2.18	1.92	2.05	2.31	0.29
94/2Q	--	--	--	2.01	2.08	2.40	0.42
94/3Q	--	--	--	--	2.11	2.30	0.53
94/4Q	--	--	--	--	--	2.01	0.37
Actual	**2.06**	**2.06**	**2.08**	**1.87**	**1.72**	**1.64**	
Average Absolute Error	0.08	0.26	0.21	0.12	0.40	0.70	0.38
	(percent error)						
93/3Q	-3.9	11.2	12.0	8.6	27.3	54.3	18.2
93/4Q	--	14.1	13.5	8.0	25.0	51.8	21.3
94/1Q	--	--	4.8	2.7	19.2	40.9	15.7
94/2Q	--	--	--	7.5	20.9	46.3	24.1
94/3Q	--	--	--	--	22.7	40.2	31.2
94/4Q	--	--	--	--	--	22.6	22.6
Average Absolute Percent Error	3.9	12.6	10.1	6.7	23.0	42.7	21.8

-- = Not applicable.
^{E} = Estimated.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B6. Residential Natural Gas Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
	(dollars per thousand cubic feet)						
93/3Q	7.51	6.02	5.88	6.46	7.63	6.17	0.26
93/4Q	--	6.04	5.88	6.46	7.61	6.13	0.24
94/1Q	--	--	6.02	6.70	7.92	6.33	0.09
94/2Q	--	--	--	6.84	8.23	6.61	0.22
94/3Q	--	--	--	--	7.84	6.35	0.12
94/4Q	--	--	--	--	--	6.22	0.01
Actual	**7.90**	**6.22**	**6.07**	**6.85**	**7.97**	**6.23**	
Average Absolute Error	0.39	0.19	0.14	0.23	0.13	0.13	0.19
	(percent error)						
93/3Q	-4.9	-3.2	-3.1	-5.7	-4.3	-1.0	3.8
93/4Q	--	-2.9	-3.1	-5.7	-4.5	-1.6	3.7
94/1Q	--	--	-0.8	-2.2	-0.6	1.6	1.3
94/2Q	--	--	--	-0.1	3.3	6.1	3.1
94/3Q	--	--	--	--	-1.6	1.9	1.8
94/4Q	--	--	--	--	--	-0.2	0.2
Average Absolute Percent Error	4.9	3.1	2.4	3.4	2.9	2.1	2.8

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B7. Residential Electricity Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
			(cents per kilowatthour)				
93/3Q	8.70	8.30	8.00	8.50	8.80	8.40	0.06
93/4Q	--	8.30	8.00	8.50	8.80	8.40	0.07
94/1Q	--	--	8.00	8.50	8.70	8.30	0.08
94/2Q	--	--	--	8.50	8.80	8.40	0.08
94/3Q	--	--	--	--	8.90	8.50	0.12
94/4Q	--	--	--	--	--	8.40	0.10
Actual	**8.76**	**8.30**	**7.90**	**8.57**	**8.86**	**8.30**	
Average Absolute Error	0.06	0.00	0.10	0.07	0.08	0.10	0.08
			(percent error)				
93/3Q	-0.7	0.0	1.3	-0.8	-0.7	1.2	0.8
93/4Q	--	0.0	1.3	-0.8	-0.7	1.2	1.2
94/1Q	--	--	1.3	-0.8	-1.8	0.0	1.0
94/2Q	--	--	--	-0.8	-0.7	1.2	0.9
94/3Q	--	--	--	--	0.5	2.4	1.4
94/4Q	--	--	--	--	--	1.2	1.2
Average Absolute Percent Error	0.7	0.0	1.3	0.8	0.9	1.2	0.9

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B8. Electric Utility Coal Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
			(dollars per million Btu)				
93/3Q	1.40	1.40	1.41	1.43	1.43	1.43	0.05
93/4Q	--	1.41	1.42	1.44	1.43	1.43	0.07
94/1Q	--	--	1.40	1.43	1.42	1.42	0.06
94/2Q	--	--	--	1.41	1.41	1.41	0.06
94/3Q	--	--	--	--	1.39	1.39	0.05
94/4Q	--	--	--	--	--	1.39	0.06
Actual	**1.38**	**1.38**	**1.36**	**1.38**	**1.35**	**1.33**	
Average Absolute Error	0.02	0.03	0.05	0.05	0.07	0.08	0.06
			(percent error)				
93/3Q	1.4	1.4	3.7	3.6	5.9	7.5	3.9
93/4Q	--	2.2	4.4	4.3	5.9	7.5	4.9
94/1Q	--	--	2.9	3.6	5.2	6.8	4.6
94/2Q	--	--	--	2.2	4.4	6.0	4.2
94/3Q	--	--	--	--	3.0	4.5	3.7
94/4Q	--	--	--	--	--	4.5	4.5
Average Absolute Percent Error	1.4	1.8	3.7	3.4	4.9	6.1	4.3

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B9. Real Disposable Personal Income, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(billion 1987 dollars)						
93/3Q	3707	3731	3749	3778	3807	3838	30
93/4Q	--	3728	3728	3751	3787	3819	54
94/1Q	--	--	3752	3767	3804	3830	45
94/2Q	--	--	--	3805	3834	3858	20
94/3Q	--	--	--	--	3844	3871	18
94/4Q	--	--	--	--	--	3867	36
Actual	**3708**	**3748**	**3779**	**3812**	**3841**	**3903**	
Average Absolute Error	1	18	36	36	27	56	36
	(percent error)						
93/3Q	0.0	-0.4	-0.8	-0.9	-0.9	-1.7	0.8
93/4Q	--	-0.5	-1.4	-1.6	-1.4	-2.2	1.4
94/1Q	--	--	-0.7	-1.2	-1.0	-1.9	1.2
94/2Q	--	--	--	-0.2	-0.2	-1.2	0.5
94/3Q	--	--	--	--	0.1	-0.8	0.5
94/4Q	--	--	--	--	--	-0.9	0.9
Average Absolute Percent Error	0.0	0.5	1.0	0.9	0.7	1.4	0.9

-- = Not applicable.

Sources: History from U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business*, various issues. Forecasts, from: DRI/McGraw-Hill, Quarterly Model of U.S. Economy, CONTROL forecasts, adjusted for EIA oil price forecasts for: June 1993, September 1993, January 1994, March 1994, July 1994, and September 1994.

Table B10. Industrial Production Index for Manufacturing, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(1987 = 1.000)						
93/3Q	1.129	1.141	1.154	1.169	1.181	1.192	0.017
93/4Q	--	1.132	1.144	1.157	1.168	1.179	0.031
94/1Q	--	--	1.157	1.171	1.179	1.188	0.023
94/2Q	--	--	--	1.179	1.191	1.201	0.016
94/3Q	--	--	--	--	1.198	1.207	0.013
94/4Q	--	--	--	--	--	1.206	0.020
Actual	**1.131**	**1.148**	**1.168**	**1.189**	**1.205**	**1.226**	
Average Absolute Error	0.002	0.011	0.016	0.020	0.022	0.030	0.021
	(percent error)						
93/3Q	-0.2	-0.6	-1.2	-1.7	-2.0	-2.8	1.4
93/4Q	--	-1.4	-2.1	-2.7	-3.1	-3.8	2.6
94/1Q	--	--	-0.9	-1.5	-2.2	-3.1	1.9
94/2Q	--	--	--	-0.8	-1.2	-2.0	1.4
94/3Q	--	--	--	--	-0.6	-1.5	1.1
94/4Q	--	--	--	--	--	-1.6	1.6
Average Absolute Percent Error	0.2	1.0	1.4	1.7	1.8	2.5	1.8

-- = Not applicable.

Sources: History from Federal Reserve System, *Statistical Release G.12.3*, various issues. Forecasts from: DRI/McGraw-Hill, Quarterly Model of U.S. Economy, CONTROL forecasts, adjusted for EIA oil price forecasts for: June 1993, September 1993, January 1994, March 1994, July 1994, and September 1994.

Table B11. Heating Degree Days, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
				(Degree Days)			
93/3Q	89	1636	2354	524	89	1636	69
93/4Q	--	1636	2354	524	89	1636	79
94/1Q	--	--	2354	524	89	1636	81
94/2Q	--	--	--	524	89	1636	80
94/3Q	--	--	--	--	89	1636	103
94/4Q	--	--	--	--	--	1636	197
Actual	**109**	**1706**	**2438**	**488**	**97**	**1439**	
Average Absolute Error	20	70	84	36	8	197	85
				(percent error)			
93/3Q	-18.3	-4.1	-3.4	7.4	-8.2	13.7	6.6
93/4Q	--	-4.1	-3.4	7.4	-25.4	13.7	6.4
94/1Q	--	--	-3.4	7.4	-25.4	13.7	7.3
94/2Q	--	--	--	7.4	-25.4	13.7	11.9
94/3Q	--	--	--	--	-25.4	13.7	13.3
94/4Q	--	--	--	--	--	13.7	13.7
Average Absolute Percent Error	18.3	4.1	3.4	7.4	8.2	13.7	9.0

-- = Not applicable.
Sources: U.S. Department of Commerce, National Oceanic and Atmospheric Administration (NOAA), Monthly State, Regional and National Heating/Cooling Degree Days, Weighted by Population; forecasts are 30-year averages of NOAA data, 1961-1990.

Table B12. Cooling Degree Days, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
				(Degree Days)			
93/3Q	758	72	30	334	758	72	23
93/4Q	--	72	30	334	758	72	17
94/1Q	--	--	30	334	758	72	19
94/2Q	--	--	--	334	758	72	23
94/3Q	--	--	--	--	758	72	15
94/4Q	--	--	--	--	--	72	3
Actual	**810**	**62**	**34**	**375**	**732**	**69**	
Average Absolute Error	52	10	4	41	26	3	19
				(percent error)			
93/3Q	-6.4	16.1	-11.8	-10.9	3.6	4.3	6.5
93/4Q	--	16.1	-11.8	-10.9	3.6	4.3	6.6
94/1Q	--	--	-11.8	-10.9	3.6	4.3	6.1
94/2Q	--	--	--	-10.9	3.6	4.3	6.0
94/3Q	--	--	--	--	3.6	4.3	3.6
94/4Q	--	--	--	--	--	4.3	4.3
Average Absolute Percent Error	6.4	16.1	11.8	10.9	3.6	4.3	7.7

-- = Not applicable.
Sources: U.S. Department of Commerce, National Oceanic and Atmospheric Administration (NOAA), Monthly State, Regional and National Heating/Cooling Degree Days, Weighted by Population; forecasts are 30-year averages of NOAA data, 1961-1990.

Table B13. Total Petroleum Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(million barrels per day)						
93/3Q	17.56	17.87	18.01	17.55	17.80	18.21	0.20
93/4Q	--	17.71	17.64	17.11	17.50	17.92	0.18
94/1Q	--	--	17.77	17.23	17.63	18.01	0.15
94/2Q	--	--	--	17.32	17.74	18.03	0.16
94/3Q	--	--	--	--	17.66	17.97	0.13
94/4Q	--	--	--	--	--	17.86	0.12
Actual	**17.44**	**17.68**	**17.82**	**16.45**	**17.69**	**17.74**	
Average Absolute Error	0.12	0.11	0.14	0.20	0.09	0.26	0.17
	(percent error)						
93/3Q	0.7	1.1	1.1	0.6	0.6	2.6	1.1
93/4Q	--	0.2	-1.0	-1.9	-1.1	1.0	1.0
94/1Q	--	--	-0.3	-1.3	-0.3	1.5	0.8
94/2Q	--	--	--	-0.7	0.3	1.6	0.9
94/3Q	--	--	--	--	0.2	1.3	0.7
94/4Q	--	--	--	--	--	0.7	0.7
Average Absolute Percent Error	0.7	0.6	0.8	1.1	0.5	1.5	1.0

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B14. Motor Gasoline Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(million barrels per day)						
93/3Q	7.64	7.45	7.24	7.60	7.73	7.54	0.09
93/4Q	--	7.49	7.20	7.57	7.71	7.53	0.08
94/1Q	--	--	7.27	7.65	7.82	7.62	0.04
94/2Q	--	--	--	7.66	7.87	7.66	0.02
94/3Q	--	--	--	--	7.84	7.57	0.04
94/4Q	--	--	--	--	--	7.55	0.10
Actual	**7.75**	**7.52**	**7.19**	**7.68**	**7.83**	**7.65**	
Average Absolute Error	0.11	0.05	0.05	0.06	0.06	0.08	0.06
	(percent error)						
93/3Q	-1.4	-0.9	0.7	-1.0	-1.3	-1.4	1.1
93/4Q	--	-0.4	0.1	-1.4	-1.5	-1.6	1.0
94/1Q	--	--	1.1	-0.4	-0.1	-0.4	0.5
94/2Q	--	--	--	-0.3	0.5	0.1	0.3
94/3Q	--	--	--	--	0.1	-1.0	0.6
94/4Q	--	--	--	--	--	-1.3	1.3
Average Absolute Percent Error	1.4	0.7	0.6	0.8	0.7	1.0	0.8

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B15. Distillate Fuel Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993		1994				Average Absolute Error
	3rd	4th	1st	2nd	3rd	4th	
				(million barrels per day)			
93/3Q	2.83	3.25	3.59	3.07	2.94	3.37	0.07
93/4Q	--	3.15	3.44	2.93	2.83	3.22	0.09
94/1Q	--	--	3.50	2.98	2.88	3.28	0.07
94/2Q	--	--	--	3.04	2.91	3.31	0.07
94/3Q	--	--	--	--	2.91	3.32	0.11
94/4Q	--	--	--	--	--	3.21	0.06
Actual	**2.82**	**3.19**	**3.53**	**3.03**	**2.96**	**3.18**	
Average Absolute Error	0.01	0.05	0.06	0.05	0.07	0.14	0.08
				(percent error)			
93/3Q	0.4	1.9	1.7	1.3	-0.7	7.0	2.2
93/4Q	--	-1.3	-2.5	-3.3	-4.4	2.2	2.7
94/1Q	--	--	-0.8	-1.7	-2.7	4.1	2.3
94/2Q	--	--	--	0.3	-1.7	5.1	2.4
94/3Q	--	--	--	--	-1.7	5.4	3.6
94/4Q	--	--	--	--	--	1.9	1.9
Average Absolute Percent Error	0.4	1.6	1.7	1.7	2.2	4.3	2.5

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B16. Residual Fuel Oil Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993		1994				Average Absolute Error
	3rd	4th	1st	2nd	3rd	4th	
				(million barrels per day)			
93/3Q	1.05	1.15	1.31	1.14	1.02	1.18	0.11
93/4Q	--	1.17	1.27	1.04	1.01	1.15	0.09
94/1Q	--	--	1.34	1.08	1.04	1.19	0.16
94/2Q	--	--	--	1.09	1.05	1.17	0.18
94/3Q	--	--	--	--	1.00	1.15	0.18
94/4Q	--	--	--	--	--	1.16	0.25
Actual	**1.07**	**1.18**	**1.25**	**0.98**	**0.88**	**0.91**	
Average Absolute Error	0.02	0.02	0.06	0.11	0.14	0.26	0.14
				(percent error)			
93/3Q	-1.8	-2.5	4.8	16.2	15.9	29.7	10.8
93/4Q	--	-0.8	1.6	6.0	14.8	26.4	8.8
94/1Q	--	--	7.2	10.1	18.2	30.8	15.6
94/2Q	--	--	--	11.1	19.3	28.6	19.5
94/3Q	--	--	--	--	13.6	26.4	20.1
94/4Q	--	--	--	--	--	27.5	27.5
Average Absolute Percent Error	1.8	1.7	4.5	10.9	16.4	28.2	14.9

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B17. Jet Fuel Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
				(million barrels per day)			
93/3Q	1.51	1.54	1.48	1.43	1.51	1.53	0.04
93/4Q	--	1.53	1.49	1.44	1.54	1.56	0.03
94/1Q	--	--	1.49	1.45	1.56	1.57	0.04
94/2Q	--	--	--	1.44	1.55	1.54	0.03
94/3Q	--	--	--	--	1.53	1.56	0.02
94/4Q	--	--	--	--	--	1.57	0.03
Actual	**1.49**	**1.48**	**1.51**	**1.52**	**1.54**	**1.54**	
Average Absolute Error	0.02	0.06	0.02	0.08	0.01	0.02	0.03
				(percent error)			
93/3Q	1.5	4.1	-2.0	-5.9	-1.9	-0.6	2.7
93/4Q	--	3.4	-1.3	-5.3	0.0	1.3	2.2
94/1Q	--	--	-1.3	-4.6	1.3	1.9	2.3
94/2Q	--	--	--	-5.3	0.6	0.0	2.0
94/3Q	--	--	--	--	-0.6	1.3	1.0
94/4Q	--	--	--	--	--	1.9	1.9
Average Absolute Percent Error	1.5	3.7	1.5	5.3	0.9	1.2	2.2

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B18. Other Petroleum Products Supplied, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
				(million barrels per day)			
93/3Q	4.53	4.49	4.38	4.30	4.60	4.59	0.12
93/4Q	--	4.36	4.24	4.13	4.41	4.45	0.08
94/1Q	--	--	4.17	4.06	4.34	4.36	0.16
94/2Q	--	--	--	4.09	4.37	4.36	0.14
94/3Q	--	--	--	--	4.38	4.37	0.13
94/4Q	--	--	--	--	--	4.37	0.16
Actual	**4.31**	**4.31**	**4.35**	**4.22**	**4.48**	**4.53**	
Average Absolute Error	0.22	0.12	0.11	0.12	0.11	0.13	0.12
				(percent error)			
93/3Q	-5.1	4.2	0.7	1.9	2.7	1.3	2.6
93/4Q	--	1.2	-2.5	-2.1	-1.6	-1.8	1.8
94/1Q	--	--	-4.1	-3.8	-3.1	-3.8	3.7
94/2Q	--	--	--	-3.1	-2.5	-3.8	3.1
94/3Q	--	--	--	--	-2.2	-3.5	2.9
94/4Q	--	--	--	--	--	-3.5	3.5
Average Absolute Percent Error	5.1	2.7	2.5	2.7	2.4	2.9	2.8

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B19. Domestic Crude Oil Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
93/3Q	6.83	6.83	6.82	6.67	6.59	6.60	0.05
93/4Q	--	6.81	6.82	6.69	6.60	6.63	0.06
94/1Q	--	--	6.85	6.73	6.66	6.69	0.11
94/2Q	--	--	--	6.62	6.56	6.61	0.01
94/3Q	--	--	--	--	6.63	6.71	0.10
94/4Q	--	--	--	--	--	6.70	0.10
Actual	**6.72**	**6.87**	**6.75**	**6.62**	**6.54**	**6.60**	
Average Absolute Error	0.11	0.05	0.08	0.06	0.07	0.06	0.06
	(percent error)						
93/3Q	1.6	-0.6	1.0	0.8	0.8	0.0	0.8
93/4Q	--	-0.9	1.0	1.1	0.9	0.5	0.9
94/1Q	--	--	1.5	1.7	1.8	1.4	1.6
94/2Q	--	--	--	0.0	0.3	0.2	0.2
94/3Q	--	--	--	--	1.4	1.7	1.5
94/4Q	--	--	--	--	--	1.5	1.5
Average Absolute Percent Error	1.6	0.7	1.2	0.9	1.0	0.9	1.0

-- = Not applicable.
P = Preliminary.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B20. Lower 48 Crude Oil Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
93/3Q	5.20	5.19	5.18	5.10	5.05	5.05	0.03
93/4Q	--	5.19	5.18	5.10	5.05	5.04	0.02
94/1Q	--	--	5.21	5.15	5.10	5.10	0.07
94/2Q	--	--	--	5.05	5.01	5.00	0.03
94/3Q	--	--	--	--	5.09	5.11	0.07
94/4Q	--	--	--	--	--	5.10	0.08
Actual	**5.24**	**5.22**	**5.14**	**5.09**	**5.04**	**5.02**	
Average Absolute Error	0.04	0.03	0.05	0.03	0.03	0.05	0.04
	(percent error)						
93/3Q	-0.8	-0.6	0.8	0.2	0.2	0.6	0.5
93/4Q	--	-0.6	0.8	0.2	0.2	0.4	0.4
94/1Q	--	--	1.4	1.2	1.2	1.6	1.3
94/2Q	--	--	--	-0.8	-0.6	-0.4	0.6
94/3Q	--	--	--	--	1.0	1.8	1.4
94/4Q	--	--	--	--	--	1.6	1.6
Average Absolute Percent Error	0.8	0.6	1.0	0.6	0.6	1.1	0.8

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B21. Alaskan Crude Oil Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
93/3Q	1.62	1.64	1.64	1.57	1.54	1.56	0.05
93/4Q	--	1.62	1.64	1.59	1.54	1.58	0.03
94/1Q	--	--	1.64	1.58	1.55	1.59	0.03
94/2Q	--	--	--	1.57	1.56	1.61	0.04
94/3Q	--	--	--	--	1.54	1.60	0.03
94/4Q	--	--	--	--	--	1.60	0.03
Actual	**1.48**	**1.65**	**1.61**	**1.53**	**1.50**	**1.59**	**0.01**
Average Absolute Error	0.14	0.02	0.03	0.05	0.05	0.01	0.04
	(percent error)						
93/3Q	9.5	-0.6	1.9	2.6	2.7	-1.9	3.1
93/4Q	--	-1.8	1.9	3.9	2.7	-0.6	2.2
94/1Q	--	--	1.9	3.3	3.3	0.0	2.1
94/2Q	--	--	--	2.6	4.0	1.3	2.6
94/3Q	--	--	--	--	2.7	0.6	1.6
94/4Q	--	--	--	--	--	0.6	0.6
Average Absolute Percent Error	9.5	1.2	1.9	3.1	3.1	0.8	2.4

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B22. Net Oil Imports, Actual Versus Forecasts (Excluding SPR)

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
93/3Q	8.21	7.96	7.84	8.55	8.73	8.48	0.36
93/4Q	--	7.64	7.41	7.99	8.20	8.03	0.29
94/1Q	--	--	7.32	7.97	8.23	8.03	0.31
94/2Q	--	--	--	8.26	8.40	8.21	0.32
94/3Q	--	--	--	--	8.36	8.13	0.44
94/4Q	--	--	--	--	--	7.89	0.28
Actual	**7.82**	**7.88**	**7.38**	**8.23**	**8.72**	**7.61**	
Average Absolute Error	0.39	0.16	0.18	0.21	0.34	0.52	0.33
	(percent error)						
93/3Q	5.0	1.0	6.2	3.9	0.1	11.4	4.5
93/4Q	--	-3.0	0.4	-2.9	-6.0	5.5	3.6
94/1Q	--	--	-0.8	-3.2	-5.6	5.5	3.9
94/2Q	--	--	--	0.4	-3.7	7.9	3.9
94/3Q	--	--	--	--	-4.1	6.8	5.4
94/4Q	--	--	--	--	--	3.7	3.7
Average Absolute Percent Error	5.0	2.0	2.5	2.6	3.9	6.8	4.2

-- = Not applicable.

SPR = Strategic Petroleum Reserve.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B23. Total Petroleum Stocks, Actual Versus Forecasts (Excluding SPR)

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(million barrels)						
93/3Q	1092	1072	1024	1067	1096	1071	20
93/4Q	--	1063	1020	1066	1088	1063	16
94/1Q	--	--	1024	1067	1090	1069	23
94/2Q	--	--	--	1043	1067	1056	14
94/3Q	--	--	--	--	1058	1054	18
94/4Q	--	--	--	--	--	1058	4
Actual	**1080**	**1060**	**987**	**1025**	**1086**	**1062**	
Average Absolute Error	12	8	36	36	13	6	18
	(percent error)						
93/3Q	1.1	1.1	3.7	4.1	0.9	0.8	1.9
93/4Q	--	0.3	3.3	4.0	0.2	0.1	1.5
94/1Q	--	--	3.7	4.1	0.4	0.7	2.2
94/2Q	--	--	--	1.8	-1.7	-0.6	1.4
94/3Q	--	--	--	--	-2.6	-0.8	1.7
94/4Q	--	--	--	--	--	-0.4	0.4
Average Absolute Percent Error	1.1	0.7	3.6	3.5	1.2	0.5	1.7

-- = Not applicable.
SPR = Strategic Petroleum Reserve.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B24. Natural Gas Demand, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(trillion cubic feet)						
93/3Q	4.00	5.23	6.73	4.82	4.18	5.37	0.15
93/4Q	--	5.07	6.65	4.65	3.98	5.26	0.18
94/1Q	--	--	6.70	4.65	3.99	5.22	0.12
94/2Q	--	--	--	4.66	4.12	5.38	0.15
94/3Q	--	--	--	--	4.16	5.43	0.15
94/4Q	--	--	--	--	--	5.43	0.23
Actual	**4.00**	**5.40**	**6.83**	**4.42**	**4.10**	**5.20**	
Average Absolute Error	0.00	0.25	0.14	0.28	0.08	0.15	0.16
	(percent error)						
93/3Q	0.0	-3.1	-1.5	9.0	2.0	3.3	3.1
93/4Q	--	-6.1	-2.6	5.2	-2.9	1.2	3.5
94/1Q	--	--	-1.9	5.2	-2.7	0.4	2.4
94/2Q	--	--	--	5.4	0.5	3.5	3.2
94/3Q	--	--	--	--	1.5	4.4	3.1
94/4Q	--	--	--	--	--	4.4	4.4
Average Absolute Percent Error	0.0	4.6	2.0	6.2	1.9	2.9	3.2

-- = Not applicable.
P = Preliminary.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B25. Natural Gas Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(trillion cubic feet)						
93/3Q	4.59	4.70	4.75	4.68	4.61	4.75	0.05
93/4Q	--	4.50	4.67	4.60	4.40	4.71	0.14
94/1Q	--	--	4.73	4.54	4.40	4.61	0.14
94/2Q	--	--	--	4.70	4.79	5.00	0.13
94/3Q	--	--	--	--	4.66	5.05	0.16
94/4Q	--	--	--	--	--	4.76	0.02
Actual	**4.52**	**4.80**	**4.69**	**4.68**	**4.67**	**4.74**	
Average Absolute Error	0.07	0.20	0.04	0.06	0.15	0.13	0.11
	(percent error)						
93/3Q	1.5	-2.1	1.3	0.0	-1.3	0.2	1.1
93/4Q	--	-6.2	-0.4	-1.7	-5.8	-0.6	3.0
94/1Q	--	--	0.9	-3.0	-5.8	-2.7	3.1
94/2Q	--	--	--	0.4	2.6	5.5	2.8
94/3Q	--	--	--	--	-0.2	6.5	3.4
94/4Q	--	--	--	--	--	0.4	0.4
Average Absolute Percent Error	1.5	4.2	0.9	1.3	3.1	2.7	2.3

-- = Not applicable.
P = Preliminary.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B26. Domestic Coal Demand, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(million tons)						
93/3Q	236.0	230.0	229.0	224.0	244.0	238.0	7.7
93/4Q	--	230.0	229.0	226.0	243.0	236.0	6.0
94/1Q	--	--	231.0	224.0	248.0	238.0	5.5
94/2Q	--	--	--	220.0	246.0	242.0	8.1
94/3Q	--	--	--	--	243.0	240.0	10.0
94/4Q	--	--	--	--	--	238.0	13.0
Actual	**251.0**	**233.0**	**239.0**	**225.0**	**248.0**	**225.0**	
Average Absolute Error	15	3	9	2	3	14	7
	(percent error)						
93/3Q	-6.0	-1.3	-4.2	-0.4	-1.6	5.8	3.2
93/4Q	--	-1.3	-4.2	0.4	-2.0	4.9	2.6
94/1Q	--	--	-3.3	-0.4	-0.0	5.8	2.3
94/2Q	--	--	--	-2.4	-0.8	7.6	3.5
94/3Q	--	--	--	--	-2.0	6.7	4.2
94/4Q	--	--	--	--	--	5.8	5.8
Average Absolute Percent Error	6.0	1.3	3.9	0.9	1.3	6.1	3.2

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(94/4Q); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B27. Coal Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(million tons)						
93/3Q	254.0	256.0	258.0	252.0	257.0	266.0	9.8
93/4Q	--	247.0	260.0	262.0	262.0	262.0	4.4
94/1Q	--	--	260.0	253.0	271.0	265.0	6.3
94/2Q	--	--	--	254.0	266.0	263.0	3.7
94/3Q	--	--	--	--	254.0	254.0	6.0
94/4Q	--	--	--	--	--	256.0	4.0
Actual	**227.0**	**241.0**	**254.0**	**256.0**	**260.0**	**260.0**	
Average Absolute Error	27.0	10.5	5.3	3.8	5.6	4.3	6.3
	(percent error)						
93/3Q	11.9	6.2	1.6	-1.6	-1.2	2.3	3.9
93/4Q	--	2.5	2.4	2.3	0.8	0.8	1.7
94/1Q	--	--	2.4	-1.2	4.2	1.9	2.4
94/2Q	--	--	--	-0.8	2.3	1.2	1.4
94/3Q	--	--	--	--	-2.3	-2.3	2.3
94/4Q	--	--	--	--	--	-1.5	1.5
Average Absolute Percent Error	11.9	4.4	2.1	1.5	2.2	1.7	2.6

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(94/4Q); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B28. Total Electricity Sales, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(billion kilowatthours)						
93/3Q	758.8	689.4	720.9	697.4	781.3	720.1	16.1
93/4Q	--	701.7	722.7	698.1	780.6	718.5	13.0
94/1Q	--	--	729.1	695.1	798.1	714.2	5.8
94/2Q	--	--	--	702.5	787.1	724.6	16.3
94/3Q	--	--	--	--	794.8	722.8	14.8
94/4Q	--	--	--	--	--	727.7	26.6
Actual	**797.5**	**691.0**	**732.4**	**692.8**	**802.7**	**701.1**	
Average Absolute Error	38.7	6.2	8.2	5.5	14.3	20.2	13.8
	(percent error)						
93/3Q	-4.9	-0.2	-1.6	0.7	-2.7	2.7	2.2
93/4Q	--	1.5	-1.3	0.8	-2.8	2.5	1.8
94/1Q	--	--	-0.5	0.3	-0.6	1.9	0.8
94/2Q	--	--	--	1.4	-1.9	3.4	2.2
94/3Q	--	--	--	--	-1.0	3.1	2.0
94/4Q	--	--	--	--	--	3.8	3.8
Average Absolute Percent Error	4.9	0.9	1.1	0.8	1.8	2.9	1.9

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B29. Residential Electricity Sales, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(billion kilowatthours)						
93/3Q	263.8	233.6	260.8	227.8	269.9	239.3	12.9
93/4Q	--	233.7	261.8	228.9	271.0	240.3	10.0
94/1Q	--	--	266.5	220.4	280.6	234.3	4.5
94/2Q	--	--	--	229.8	272.3	241.5	11.9
94/3Q	--	--	--	--	280.6	242.1	9.2
94/4Q	--	--	--	--	--	241.6	13.5
Actual	**292.1**	**231.2**	**273.7**	**220.3**	**285.0**	**228.1**	
Average Absolute Error	28.3	3.0	10.7	6.4	10.1	11.8	10.1
	(percent error)						
93/3Q	-9.7	1.0	-4.7	3.4	-5.3	4.9	5.1
93/4Q	--	1.5	-4.3	3.9	-4.9	5.3	4.1
94/1Q	--	--	-2.6	0.0	-1.5	2.7	1.8
94/2Q	--	--	--	4.3	-4.5	5.9	4.9
94/3Q	--	--	--	--	-1.5	6.1	3.6
94/4Q	--	--	--	--	--	5.9	5.9
Average Absolute Percent Error	9.7	1.3	3.9	2.9	3.6	5.9	4.0

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B30. Commercial Electricity Sales, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(billion kilowatthours)						
93/3Q	217.3	195.8	195.8	197.6	226.4	204.4	4.3
93/4Q	--	195.7	195.3	197.1	225.7	203.6	3.6
94/1Q	--	--	195.6	197.2	229.0	201.8	2.2
94/2Q	--	--	--	196.3	225.5	203.6	4.6
94/3Q	--	--	--	--	229.0	204.6	3.9
94/4Q	--	--	--	--	--	207.0	8.7
Actual	**225.2**	**191.4**	**194.5**	**199.9**	**230.5**	**198.3**	
Average Absolute Error	7.9	4.3	1.1	2.9	3.4	5.9	4.0
	(percent error)						
93/3Q	-3.5	2.3	0.7	-1.2	-1.8	3.1	2.1
93/4Q	--	2.2	0.4	-1.4	-2.1	2.7	1.8
94/1Q	--	--	0.6	-1.4	-0.7	1.8	1.1
94/2Q	--	--	--	-1.8	-2.2	2.7	2.2
94/3Q	--	--	--	--	-0.7	3.2	1.8
94/4Q	--	--	--	--	--	4.4	4.4
Average Absolute Percent Error	3.5	2.3	0.5	1.4	1.5	3.0	1.9

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B31. Industrial Electricity Sales, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(billion kilowatthours)						
93/3Q	252.7	245.3	240.7	248.8	260.1	252.4	1.2
93/4Q	--	247.8	242.0	249.0	259.1	250.9	1.6
94/1Q	--	--	242.3	254.0	262.7	254.4	2.5
94/2Q	--	--	--	252.6	263.7	255.3	2.8
94/3Q	--	--	--	--	260.0	252.1	1.1
94/4Q	--	--	--	--	--	255.1	3.4
Actual	**256.0**	**245.2**	**240.3**	**249.5**	**261.9**	**251.7**	
Average Absolute Error	3.3	1.3	1.4	2.2	1.8	1.9	1.9
	(percent error)						
93/3Q	-1.3	-0.2	0.2	-0.3	-0.7	0.3	0.5
93/4Q	--	0.8	0.7	-0.2	-1.1	-0.3	0.6
94/1Q	--	--	0.8	1.8	0.3	1.1	1.0
94/2Q	--	--	--	1.2	0.7	1.4	1.1
94/3Q	--	--	--	--	0.7	0.2	0.4
94/4Q	--	--	--	--	--	1.4	1.4
Average Absolute Percent Error	1.3	0.5	0.6	0.9	0.7	0.8	0.7

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B32. Electricity Generation from Coal, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(billion kilowatthours)						
93/3Q	417.5	400.5	400.1	397.5	433.2	417.3	15.0
93/4Q	--	401.5	400.9	401.7	431.1	414.2	12.1
94/1Q	--	--	406.3	399.6	442.3	417.7	13.3
94/2Q	--	--	--	389.3	439.2	426.8	15.4
94/3Q	--	--	--	--	433.0	424.1	19.2
94/4Q	--	--	--	--	--	419.6	31.2
Actual	**448.6**	**407.0**	**414.4**	**393.6**	**435.6**	**388.4**	
Average Absolute Error	31.1	6.0	15.0	5.6	4.0	31.6	15.2
	(percent error)						
93/3Q	-6.9	-1.6	-4.1	1.0	-0.6	7.4	3.6
93/4Q	--	-1.4	-4.0	2.1	-1.0	6.6	3.0
94/1Q	--	--	-2.7	1.5	1.5	7.5	3.2
94/2Q	--	--	--	-1.1	0.8	9.9	3.8
94/3Q	--	--	--	--	-0.6	9.2	4.6
94/4Q	--	--	--	--	--	8.0	8.0
Average Absolute Percent Error	6.9	1.5	3.6	1.4	0.9	8.1	3.8

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B33. Electricity Generation from Petroleum, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
	(billion kilowatthours)						
93/3Q	27.0	22.0	27.2	30.4	29.1	23.8	6.5
93/4Q	--	20.3	25.6	24.2	27.7	22.8	5.6
94/1Q	--	--	28.2	25.9	28.6	24.1	5.9
94/2Q	--	--	--	28.8	31.0	25.8	8.8
94/3Q	--	--	--	--	28.0	24.6	9.0
94/4Q	--	--	--	--	--	24.8	10.9
Actual	**33.1**	**25.4**	**32.2**	**24.5**	**20.7**	**13.9**	
Average Absolute Error	6.1	4.2	5.2	3.0	8.2	10.4	6.9
	(percent error)						
93/3Q	-18.4	-13.4	-15.5	24.1	40.6	71.2	25.8
93/4Q	--	-20.1	-20.5	-1.2	33.4	64.0	23.9
94/1Q	--	--	-12.4	5.7	38.2	73.4	25.7
94/2Q	--	--	--	17.6	49.8	85.6	44.8
4/3Q	--	--	--	--	35.3	77.0	52.0
94/4Q	--	--	--	--	--	78.4	78.4
Average Absolute Percent Error	18.4	16.7	16.1	12.1	39.5	74.9	37.9

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B34. Electricity Generation from Natural Gas, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1993		1994				
	3rd	4th	1st	2nd	3rd	4th	
	(billion kilowatthours)						
93/3Q	85.9	58.6	48.9	72.3	89.8	62.5	4.3
93/4Q	--	59.6	51.0	72.5	90.6	63.1	3.9
94/1Q	--	--	51.4	71.1	92.3	62.8	4.3
94/2Q	--	--	--	68.0	88.9	62.1	7.5
94/3Q	--	--	--	--	90.1	62.9	8.3
94/4Q	--	--	--	--	--	62.6	6.5
Actual	**90.9**	**60.7**	**49.6**	**71.7**	**100.6**	**69.1**	
Average Absolute Error	5.0	1.6	1.3	1.4	10.3	6.4	5.1
	(percent error)						
93/3Q	-5.5	-3.5	-1.4	0.8	-10.7	-9.6	5.8
93/4Q	--	-1.8	2.8	1.1	-9.9	-8.7	5.5
94/1Q	--	--	3.6	-0.8	-8.3	-9.1	5.8
94/2Q	--	--	--	-5.2	-11.6	-10.1	9.3
94/3Q	--	--	--	--	-10.4	-9.0	9.8
94/4Q	--	--	--	--	--	-9.4	9.4
Average Absolute Percent Error	5.5	2.6	2.6	2.0	10.2	9.3	6.4

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B35. Electricity Generation from Nuclear Power, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(billion kilowatthours)						
93/3Q	170.7	156.8	158.8	139.5	170.4	156.8	7.1
93/4Q	--	159.8	161.4	141.8	173.2	159.9	6.4
94/1Q	--	--	160.1	139.7	170.7	157.5	5.6
94/2Q	--	--	--	149.5	163.2	150.1	11.4
94/3Q	--	--	--	--	171.5	150.4	9.8
94/4Q	--	--	--	--	--	156.2	10.3
Actual	**162.7**	**144.4**	**154.6**	**143.5**	**174.9**	**166.5**	
Average Absolute Error	8.0	13.9	5.5	3.9	5.1	11.4	7.7
	(percent error)						
93/3Q	4.9	8.6	2.7	-2.8	-2.6	-5.8	4.5
93/4Q	--	10.7	4.4	-1.2	-1.0	-4.0	4.1
94/1Q	--	--	3.6	-2.6	-2.4	-5.4	3.5
94/2Q	--	--	--	4.2	-6.7	-9.8	7.0
94/3Q	--	--	--	--	-1.9	-9.7	5.7
94/4Q	--	--	--	--	--	-6.2	6.2
Average Absolute Percent Error	4.9	9.6	3.6	2.7	2.9	6.8	4.8

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table B36. Electricity Generation from Hydroelectric Power, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1993 3rd	1993 4th	1994 1st	1994 2nd	1994 3rd	1994 4th	Average Absolute Error
	(billion kilowatthours)						
93/3Q	64.1	64.2	74.4	76.4	63.6	62.5	7.6
93/4Q	--	66.2	74.9	78.1	64.3	62.4	9.3
94/1Q	--	--	70.7	76.3	62.6	61.1	6.8
94/2Q	--	--	--	73.3	60.9	60.1	4.0
94/3Q	--	--	--	--	59.4	59.5	3.7
94/4Q	--	--	--	--	--	58.0	2.9
Actual	**60.3**	**55.9**	**61.1**	**70.9**	**56.4**	**55.1**	
Average Absolute Error	3.8	9.3	3.3	5.1	5.8	11.1	6.7
	(percent error)						
93/3Q	6.3	14.8	21.8	7.8	12.8	13.4	12.6
93/4Q	--	18.4	22.6	10.2	14.0	13.2	15.5
94/1Q	--	--	15.7	7.6	11.0	10.9	11.2
94/2Q	--	--	--	3.4	8.0	9.1	6.5
94/3Q	--	--	--	--	5.3	8.0	6.6
94/4Q	--	--	--	--	--	5.3	5.3
Average Absolute Percent Error	6.3	16.6	20.0	7.2	10.2	10.0	11.4

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/03); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Appendix C

Regression Results

(Chapter 5)

Table C1. Field Production of Other Hydrocarbons/Oxygenates (OHRIPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
OHRIPUS	15	105	0.05362	0.0005107	0.02260	0.880	0.864	2.354

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
OHRI_B0	-0.00070	0.01235	-0.57	0.5706	OHRIPUS constant coefficient
OHRI_MT	1.16536	0.10540	11.06	0.0001	OHRIPUS coef of MTPRPUS
OHRI_D9301	0.33709	0.02216	15.21	0.0001	OHRIPUS coef of D9301
OHRI_E1	0.01728	0.00907	1.91	0.0595	OHRIPUS coef of JAN
OHRI_E2	-0.01131	0.01020	-1.11	0.2702	OHRIPUS coef of FEB
OHRI_E3	0.00295	0.01076	0.27	0.7845	OHRIPUS coef of MAR
OHRI_E4	-0.00810	0.01095	-0.74	0.4612	OHRIPUS coef of APR
OHRI_E5	-0.00578	0.01103	-0.52	0.6013	OHRIPUS coef of MAY
OHRI_E6	-0.00398	0.01107	-0.36	0.7201	OHRIPUS coef of JUN
OHRI_E7	0.00100	0.01100	0.09	0.9274	OHRIPUS coef of JUL
OHRI_E8	-0.00505	0.01091	-0.46	0.6445	OHRIPUS coef of AUG
OHRI_E9	-0.00296	0.01067	-0.28	0.7821	OHRIPUS coef of SEP
OHRI_E10	0.00340	0.01008	0.34	0.7365	OHRIPUS coef of OCT
OHRI_E11	0.01284	0.00847	1.52	0.1326	OHRIPUS coef of NOV
OHRI_L1	0.41779	0.09339	4.47	0.0001	OHRIPUS 1st-order autocorrelation coefficient

Method of Estimation: OLS with 1st-order autocorrelation coefficient
RANGE of Fit: 8501 TO 9412

OHRIPUS = Field production of other hydrocarbons/oxygenates, million barrels per day
MTPRPUS = Plant production of methyl tertiary butyl ether (MTBE), million barrels per day
D9301 = Dummy variable = 1 if January 1993, = 0 otherwise
JAN -> NOV = Monthly dummy variables

Table C2. Refinery Inputs of Other Petroleum Products (PSRIPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PSRIPUS	14	106	0.28063	0.0026475	0.05145	0.6836	0.6448	1.716

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PSRI_B0	0.01564	0.02121	0.74	0.4625	PSRIPUS constant coefficient
PSRI_MB	0.87518	0.07465	11.72	0.0001	PSRIPUS coef of MBFPPUS
PSRI_MT	0.73635	0.10838	6.79	0.0001	PSRIPUS coef of MTTCPUS
PSRI_E2	0.02036	0.02305	0.88	0.3792	PSRIPUS coef of FEB
PSRI_E3	0.11966	0.02332	5.13	0.0001	PSRIPUS coef of MAR
PSRI_E4	0.11602	0.02349	4.94	0.0001	PSRIPUS coef of APR
PSRI_E5	0.05484	0.02360	2.32	0.0221	PSRIPUS coef of MAY
PSRI_E6	0.07297	0.02351	3.10	0.0025	PSRIPUS coef of JUN
PSRI_E7	0.04425	0.02369	1.87	0.0645	PSRIPUS coef of JUL
PSRI_E8	0.06794	0.02361	2.88	0.0048	PSRIPUS coef of AUG
PSRI_E9	-0.02008	0.02316	-0.87	0.3878	PSRIPUS coef of SEP
PSRI_E10	0.09632	0.02315	4.16	0.0001	PSRIPUS coef of OCT
PSRI_E11	0.06064	0.02328	2.61	0.0105	PSRIPUS coef of NOV
PSRI_E12	0.07100	0.02333	3.04	0.0029	PSRIPUS coef of DEC

Method of Estimation: OLS
RANGE of Fit: 8301 TO 9412

PSRIPUS = Refinery inputs of other petroleum products, million barrels per day
MBFPPUS = Field production of motor gasoline blending components, million barrels per day
MTTCPUS = MTBE demand, million barrels per day
FEB -> DEC = Monthly dummy variables

Table C3. Refinery Inputs of Other Hydrocarbons/Oxygenates (OXRIPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
OXRIPUS	14	106	0.03758	0.0003546	0.01883	0.9322	0.9239	2.324

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
OXRI_B0	0.07105	0.02931	2.42	0.0170	OXRIPUS constant coefficient
OXRI_MT	0.51704	0.06385	8.10	0.0001	OXRIPUS coef of MTTCPUS
OXRI_E2	-0.02105	0.00571	-3.69	0.0004	OXRIPUS coef of FEB
OXRI_E3	-0.01922	0.00785	-2.45	0.0160	OXRIPUS coef of MAR
OXRI_E4	-0.02587	0.00904	-2.86	0.0051	OXRIPUS coef of APR
OXRI_E5	-0.02796	0.00981	-2.85	0.0053	OXRIPUS coef of MAY
OXRI_E6	-0.02479	0.01036	-2.39	0.0184	OXRIPUS coef of JUN
OXRI_E7	-0.02922	0.01053	-2.78	0.0065	OXRIPUS coef of JUL
OXRI_E8	-0.02577	0.01033	-2.49	0.0142	OXRIPUS coef of AUG
OXRI_E9	-0.01996	0.00977	-2.04	0.0436	OXRIPUS coef of SEP
OXRI_E10	-0.00583	0.00904	-0.64	0.5207	OXRIPUS coef of OCT
OXRI_E11	0.00454	0.00792	0.57	0.5679	OXRIPUS coef of NOV
OXRI_E12	-0.00307	0.00606	-0.51	0.6135	OXRIPUS coef of DEC
OXRI_L1	0.94255	0.04087	23.06	0.0001	OXRIPUS !st-order autocorrelation coefficient

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8301 TO 9412

OXRIPUS = Refinery inputs of other/hydrocarbons and oxygenates, million barrels per day
MTTCPUS = MTBE demand, million barrels per day
FEB -> DEC = Monthly dummy variables