DOE/EIA-0202(94)
Distribution Category UC-950

Short-Term Energy Outlook
Annual Supplement 1994

Energy Information Administration
Office of Energy Markets and End Use
U.S. Department of Energy
Washington, DC 20585

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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 chapters 2 through 5 follows below:

Chapter 2 presents an analysis of likely effects of the Clean Air Act Amendments of 1990 as they affect reformulated gasoline. The Amendments require the sale of reformulated gasoline on December 1, 1994, in order to reduce automobile emissions, particularly during the high summer season. This chapter analyzes the effects that this regulation will have on demand, supply, and price of motor gasoline.

Chapter 3 compares the Energy Information Administration's base or "mid" case energy projections for 1994 and 1995 as published in the first quarter 1994 *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 tend to be on the high side (except for prices) compared to the other forecasts for economic growth and energy demand.

Chapter 4 evaluates the overall accuracy of the short-term energy forecasts published in the third quarter 1992 through the fourth quarter 1993 *Outlooks*. 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 1992 through the end of 1993. This period covers generally declining world oil prices, but at the same time large fluctuations for natural gas wellhead prices. In addition, there are evaluations of one-year-ahead forecasts for several major energy variables for 1986 through 1993 which adds historical depth to the analysis.

Chapter 5 provides a discussion on the methodology of forecasting the demand for "other" petroleum products which includes 14 miscellaneous products representing 14 percent of total petroleum product demand. Included in this chapter are linear regression equations and summary regression analysis results.

2. Demand, Supply and Price Outlook for Reformulated Gasoline, 1995

The reformulated gasoline provisions of the Clean Air Act Amendments of 1990 (CAAA90) require reductions in automobile emissions of ozone-forming volatile organic compounds (VOC) during the summer high ozone season, and toxic air pollutants (TAP) during the entire year in certain areas of the United States.[1] The new regulations, effective December 1, 1994, mandate the sale of reformulated gasoline in the nine largest metropolitan areas with the most severe summer ozone levels and other ozone nonattainment areas that opt in to the program. (States with ozone nonattainment areas may apply to the EPA to enter the reformulated gasoline program). The regulations also prohibit gasoline sold in the rest of the country from becoming more polluting than it was in 1990. This provision is intended to ensure that refiners do not "dump" into conventional gasoline what they can no longer use in reformulated gasoline.

Summary

This chapter analyzes the new regulations' impact on the motor gasoline market and evaluates the constraints and costs faced by the petroleum refining industry in complying with them. The forecasts in this article are based on the *Short-Term Energy Outlook*, which is published quarterly by the Energy Information Administration.[2] The supply, demand and price forecasts in this chapter do not include provisions for a minimum use of renewable oxygenates, which had been proposed but not yet promulgated by the Environmental Protection Agency (EPA) at the time this chapter was prepared.[3]

Demand for reformulated gasoline is expected to represent almost 35 percent of total motor gasoline demand in 1995. Demand projections for reformulated gasoline are based on the 1990 populations of the participating ozone nonattainment areas and projected per-capita gasoline demands. Corrections are made for "spillover" of reformulated gasoline to areas that won't require reformulated gasoline, changes in automobile fuel efficiency, and the price elasticity of demand.

Refineries will have to change operating procedures, make plant modifications, and obtain new process equipment in order to meet the new oxygenate, vapor pressure, and benzene specifications and emissions reduction requirements for reformulated gasoline. Nevertheless, there have been no indications that the domestic refining industry will be unable to meet the demand for reformulated gasoline. If supply were to be insufficient, the EPA can delay the program in opt-in areas for up to 3 years. EPA reports that it has not received any petitions to delay implementation of the reformulated gasoline program and believes that there will be more than sufficient supply given the current level of opt-ins.

The minimum oxygenate requirements for reformulated gasoline will increase demand for the oxygenates: ethanol, methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), and tertiary amyl methyl ether (TAME). Total demand is expected to increase from the 1993 average of 319,100 barrels per day of MTBE-equivalent volume to an average 480,000 barrels per day of MTBE-equivalent volume in 1995. New oxygenate domestic production capacity and imports should be adequate to satisfy this surge in demand.

Refiners will incur higher operating and capital costs in producing reformulated gasoline. The costs of oxygenate blending, lower gasoline vapor pressure, and reduced benzene and aromatics concentrations are expected to yield a reformulated gasoline wholesale price premium of 3.5 to 4.0 cents per gallon over conventional unleaded gasoline. The retail price premium may be greater due to testing and compliance costs and to the costs of handling and transporting the additional grades of gasoline, which must be segregated

in the distribution system. In addition, the wider use of oxygenates, which have a lower energy content than the motor gasoline components they displace, will raise consumers' effective final costs by imposing fuel-economy penalties.

Program Requirements

The CAAA90 regulations require that beginning January 1, 1995, all reformulated gasoline at retail outlets must meet the following minimum requirements:[4]

- The oxygen content of reformulated gasoline shall equal or exceed 2.0 percent by weight (equivalent to 11.15 percent MTBE or 5.5 percent ethanol by volume).

- The benzene content of reformulated gasoline shall not exceed 1.0 percent by volume.

- Reformulated gasoline shall have no heavy metals, including lead or manganese.

- The emissions of nitrogen oxides (NO_x) when using reformulated gasoline shall be no greater than such emissions from 1990 model year automobiles operated on a specified baseline gasoline.

In addition to these minimum requirements, reformulated gasoline must also meet VOC and TAP emissions reduction targets. The new VOC and TAP emissions standards are to be implemented in two phases. The Phase I reformulated gasoline regulations, effective from 1995 to 2000, require a minimum 15 percent reduction in VOC and TAP emissions from 1990 model year automobiles operated on a specified baseline gasoline. The VOC emissions reduction is required only during the summer high ozone season, which lasts from June 1 to September 15. The TAP emissions reduction requirement applies during the entire year. (The Phase II emission performance standards will take effect in 2000, and will require greater reductions in VOC, TAP, and NO_x emissions. They are not discussed in this article.)

A two-stage approach is taken in implementing the Phase I program. The first stage uses the EPA's "simple" emissions model to certify that gasoline meets the VOC and TAP reduction standards. Under the second stage, the EPA's "complex" emissions model would supplant the simple model and take effect on January 1, 1998.

The simple model, which relates gasoline composition to the fuel's VOC and TAP emissions, is limited to the effects of gasoline oxygen content, Reid vapor pressure (RVP), and aromatics content. Reformulated gasoline satisfying the above-minimum specifications and the following additional composition requirements will meet the Phase I simple model NO_x, VOC, and TAP emissions performance standards:

- Oxygen: 2.7 percent by weight maximum during summer high ozone season. Maximum 3.5 percent oxygen at other times. States can elect to apply the summer high ozone season 2.7 percent limit during the winter if the use of higher oxygenate levels are found to cause other air quality problems.

- Reid Vapor Pressure: 7.2 psi RVP maximum in Southern areas (EPA VOC Control Region 1) and 8.1 psi RVP maximum in northern areas (EPA Region 2), during the high ozone season of June 1 through September 15. RVP controls also apply May 1 through May 31 for facilities upstream of retail outlets such as refineries, pipelines, and terminals.

- Aromatics: determined by the emissions model for the required TAP reductions.

- Each refiner's annual average levels of sulfur, olefins, and the temperature at which 90 percent of the fuel vaporizes (T_{90}), must not exceed their 1990 averages for these parameters.

The complex model expands the number of variables that refiners can control to produce qualifying reformulated gasoline (e.g., sulfur, olefins, and distillation range). This additional flexibility should provide a more cost-effective method for complying with the emissions reduction requirements. Refiners will have the option of using the complex model during the first stage to show that their fuel meets the emissions standards. However, because early use of the complex model in place of the simple model by a refiner during stage I would require segregation of that blend in the gasoline distribution system and at retailer outlets, this option is expected to be used by only a very few refineries.

Antidumping: The CAAA90 antidumping regulation requires that conventional gasoline produce no more exhaust benzene emissions than each refiner's or importer's average 1990 gasoline quality. Sulfur, olefins, and T_{90} are capped at 125 percent of each refiner's 1990 average. In other words, refiners cannot dump the benzene extracted from their reformulated gasoline pool into conventional gasoline. Importers that lack actual 1990 gasoline quality data to establish an individual baseline will be subject to meeting baseline gasoline specifications established by the CAAA90 and the EPA.

Averaging and Credit Trading: Individual refiners and importers will have the option of meeting the oxygen and benzene content and VOC and TAP emissions reduction targets on an average rather than on a per-gallon basis. The averaging program will require that all reformulated gasoline produced at each refinery, or imported, which does not meet the standards on a per-gallon basis, must meet somewhat more stringent averaged standards over an averaging period. For example, the RVP specification is lowered by 0.1 psi and the oxygen requirement is raised by 0.1 percent for refiners who wish to take advantage of averaging. Credits for oxygen and benzene content (but not VOC or TAP) may be purchased from other parties to meet the averaged standards for these parameters.

California Clean Gasoline Program: California has established its own gasoline composition standards that take effect statewide on March 1, 1996. The California Air Resources Board (CARB) regulations are more stringent than those of the Federal Phase I reformulated gasoline program. The CARB specifications (on a per-gallon basis) are: 25 volume percent aromatics content, 6 volume percent olefin content, 7.0 psi RVP summer maximum, 40 parts per million (ppm) sulfur content maximum, 1.8 to 2.2 weight percent oxygen content, 210° F T_{50} maximum, and 300° F T_{90} maximum.[5] The Federal standards will apply to the California ozone nonattainment areas mandated by the CAAA90 between January 1, 1995, and the time the new CARB regulations take effect.

Reformulated Gasoline Demand

Projections of reformulated gasoline demand begin with estimates of baseline demand for gasoline in the nine cities where the CAAA90 mandates sales of reformulated gasoline and other areas that "opt-in" to the reformulated gasoline program. Baseline demands are estimated from 1990 population counts and projected per capita gasoline demands and then adjusted for the following factors that may alter demand both inside and outside required reformulated gasoline sales areas:

- Delivery ("spillover") of reformulated gasoline to areas that do not require it under the regulations
- Changes in automobile fuel efficiency with reformulated gasoline
- Price elasticity of demand.

The baseline demand for reformulated gasoline, primarily from the ozone nonattainment areas in the Northeast States, the Midwest, Texas, and California, represents about 32.5 percent of total U.S. motor gasoline demand. Spillovers, changes in fuel efficiency, and demand responses to price are projected to increase the total reformulated gasoline market share to about 34.4 percent of total motor gasoline demand (Table 1).

This projection is consistent with the results from the 1992 National Petroleum Council (NPC) survey of refineries which showed that 121 respondents (representing about 86 percent of U.S. crude oil atmospheric distillation capacity) expected to produce 7,291 barrels per day of gasoline in 1995, of which 36.2 percent would be reformulated.[6]

Baseline Demand for Reformulated Gasoline: Sale of reformulated gasoline is mandated in the nine largest metropolitan areas that have the most severe summertime ozone pollution problems and 35 other cities, counties, or entire States that have "opted-in" to the reformulated gasoline program. About 35 percent of the total U.S. population live in reformulated gasoline marketing areas and consume 32.5 percent of the Nation's gasoline (Table 1).

Mandated Control Areas: Marketing of reformulated gasoline is mandated for the nine largest metropolitan areas that have the most severe summertime ozone pollution problems based on noncompliance with ozone air-quality standards from 1987 through 1989. Those nine ozone nonattainment areas contain over 23 percent of the total U.S. population (Table 2).

Opt-Ins: Any State with ozone nonattainment areas may apply to the EPA to opt-in to the reformulated gasoline program. The reformulated gasoline requirements will then apply to those state nonattainment areas on January 1, 1995, or 1 year after an application is received by the EPA, whichever is later. The EPA may delay a State's petition to opt-in to the program for up to 3 years if the domestic capacity to produce reformulated gasoline is determined to be insufficient. The EPA has published opt-in applications from 13 States and the District of Columbia.[7] The opt-in ozone nonattainment areas contain about 12 percent of the total U.S. population (Table 3).

Potential Opt-Ins: An additional 51 cities or counties (excluding California) are ozone nonattainment areas and are eligible to opt-in to the reformulated gasoline program (Table 4). Rather than opt-in, some States are considering alternatives for reducing local ozone levels. One leading option is to apply only the low RVP requirement of the reformulated gasoline program.[8] Because of the required 1-year delay between application to opt-in to the reformulated gasoline program and actual participation, these potential opt-in areas are not included in 1995 reformulated gasoline demand projections.

Table 1. Population and Gasoline Demand Shares for Reformulated Gasoline by Petroleum Administration for Defense (PAD) District

PAD District	Percent Population in Reformulated Gasoline Marketing Areas: Mandated Areas	Opt-In Areas	Totals	Gasoline Demand, 1995 (thousand barrels per day): Total	Reformulated
IA - New England	15.5	74.8	90.3%	373	337
IB - Central Atlantic	58.5	26.9	85.3	1,083	924
IC - Lower Atlantic	0.0	9.8	9.8	1,262	123
II - Midwest	13.6	1.4	15.0	2,254	338
III - Gulf Coast	11.8	11.2	23.0	1,079	248
IV - Rocky Mountain	0.0	0.0	0.0	241	0
V (ex CA) - West Coast	0.0	0.0	0.0	460	0
V (CA only) - California	57.2	0.0	57.2	902	516
U.S. Totals	**23.3**	**12.0**	**35.3**	**7,654**	**2,486**
Spillover to Nonrequired Areas (5 percent)				-	126
Reduced Automobile Fuel Efficiency (1.6 percent)				42	42
Price Elasticity of Demand (-0.6 percent)				(16)	(16)
Total Motor Gasoline Demand				**7,680**	**2,638** (34.4%)

Notes: • Total gasoline demand shares by PAD District are based on 1992 demand shares reported by the Federal Highway Administration, *Highway Statistics 1992*, FHWA-93-023 (Washington, DC, 1993), p. 10. • Total Motor Gasoline Demand is from the *Short-Term Energy Outlook*, Second Quarter 1994.

Table 2. Population of Ozone Nonattainment Areas Required to Participate in Reformulated Gasoline Program

City	EPA VOC Control Region	PAD District	Population (thousands)
Hartford, CT	2	IA	1,086
New York, NY-NJ-CT	2	IA & IB	18,087
Philadelphia, PA-NJ-DE-MD	2	IB	6,010
Baltimore, MD	1	IB	2,382
Chicago, IL-IN-WI	2	II	8,066
Milwaukee-Racine, WI	2	II	1,607
Houston-Galveston-Brazoria, TX	1	III	3,731
Los Angeles-Anaheim-Riverside, CA	1	V	14,532
San Diego, CA	1	V	2,498
Total Population, Mandated Ozone Nonattainment Areas			**57,999**
Total United States Population, 1990 Census			**248,710**

Sources: *Federal Register*, Vol. 59, No. 32 (Washington, DC, February 16, 1994), pp. 7808, 7851; National Petroleum Council, *U.S. Petroleum Refining*, Vol. IV, Part 1 (Washington, DC, August 1993), pp. L.III.5-8 - L.III.5-30; 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.

Spillover to Areas Not Requiring Reformulated Gasoline: "Spillover" refers to the supply of reformulated gasoline to areas that do not require it because segregation of reformulated and conventional gasoline may be difficult or costly. This situation arises because the geographic definitions of reformulated gasoline marketing areas do not coincide with normal distribution patterns; that is, many pipelines and terminals serve both areas that require reformulated gasoline and those that do not. The expected price differential between reformulated and conventional gasoline should provide a strong incentive for refiners and marketers to minimize spillover.

Spillover is likely to be highest in PAD Districts IA and IB (the Northeast and Central Atlantic States) where mandated and opt-in reformulated gasoline markets represent over 85 percent of the regions' population. The small demand shares for conventional gasoline in these areas may result in higher handling and transportation costs thereby minimizing the economic incentive to eliminate spillover. Experience from the oxygenated gasoline program during the winter of 1992-1993 indicates that spillover rates as low as 2 percent are feasible.[9] EIA assumes a reformulated gasoline spillover rate of 5 percent of baseline demand (126,000 barrels per day).[10]

Automobile Fuel Efficiency: Automobile fuel efficiency is expected to suffer somewhat from the switch to reformulated gasoline (and thus affect demand) because the energy (Btu) content of oxygenates is lower than that of conventional gasoline or octane blendstocks (e.g., aromatics) that the oxygenates will displace (Table 5). This loss will be partially offset by the lower summer RVP requirement, which will reduce both evaporative emissions and the volume of low-energy content butane in gasoline.

Summer gasoline reformulated with MTBE as the oxygenate is calculated to depress the Btu value of gasoline by 1,900 Btu per gallon, or 1.7 percent. Summer gasoline reformulated with ethanol has a Btu content about 1.3 percent less than the baseline conventional gasoline. Winter reformulated gasoline, which does not require RVP reductions, should result in fuel efficiency losses of about 0.3 percent higher. A reduction in fuel efficiency of 1.6 percent is assumed, which is consistent with EPA estimates of fuel economy reduction of about 2 percent with the addition of

Table 3. Population of Reformulated Gasoline Opt-In Areas

State	EPA VOC Control Region	PAD District	Opt-In Population (thousands)
Connecticut	2	IA	1,240
Maine	2	IA	809
Massachusetts	2	IA	6,016
New Hampshire	2	IA	806
Rhode Island	2	IA	1,003
Delaware	2	IB	113
District of Columbia	1	IB	607
Maryland	1	IB	1,807
New Jersey	2	IB	411
New York	2	IB	2,471
Pennsylvania	2	IB	6,331
Virginia	1	IC	3,663
Kentucky	2	II	1,029
Texas	1	III	3,560
Total Population, Ozone Nonattainment Opt-In Areas			**29,868**

Sources: *Federal Register*, Vol. 59, No. 32 (Washington, DC, February 16, 1994), pp. 7808, 7851; National Petroleum Council, *U.S. Petroleum Refining*, Vol. IV, Part 1 (Washington, DC, August 1993), pp. L.III.5-8 - L.III.5-30; 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.

oxygenates, offset by a 0.3 percent increase with the lowering of RVP.[11]

Price Elasticity of Demand: Because gasoline demand is relatively inelastic with respect to change in its own price, the demand for reformulated gasoline is projected to be only modestly affected by its price premium. EIA estimates the short-term price elasticity of gasoline demand is about -0.11, so that a 5-percent increase in the price of gasoline will lead to a 0.6-percent reduction in gasoline demand.[12] Assuming an average 1995 reformulated gasoline demand of about 2.6 million barrels per day, a 5-percent increase in gasoline price in reformulated gasoline market areas will reduce demand by only about 16,000 barrels per day.

Reformulated Gasoline Supply

Although production of reformulated gasoline will require significant changes to refinery operations and capital investment of up to $4 billion,[13] there have been no indications that the domestic refining industry will be unable to meet demand for reformulated gasoline in 1995. If reformulated gasoline supply was insufficient to meet demand, the EPA has authority to delay the program in opt-in areas for up to 3 years. The EPA reports that it has not received any petitions to delay implementation of the reformulated gasoline program and believes that there will be more than sufficient supply given the current level of opt-ins.[14]

Refiners must change operations to meet the following reformulated gasoline quality requirements:

- Benzene and aromatics reduction
- RVP reduction
- Oxygenate addition.

Benzene and Aromatics Reduction: Refiners have several options for reducing the benzene and aromatics content of their gasoline. The most commonly pursued options focus on the two largest sources of benzene and aromatics in a refinery: the Fluid Catalytic Cracker (FCC) and the Reformer (Table 6). FCC gasoline contains about 29 percent aromatics by volume and makes up about 41 percent of the total gasoline pool. Reformer product (reformate) contains about 66 percent

Table 4. Population of Potential Reformulated Gasoline Opt-In Areas by Petroleum Administration for Defense (PAD) District

PAD District	Potential Opt-In Area Population (thousands)	Percent of Total Population
IA - New England	0	0.0%
IB - Central Atlantic	0	0.0%
IC - Lower Atlantic	12,385	33.0%
II - Midwest	24,325	34.1%
III - Gulf Coast	2,734	8.6%
IV - Rocky Mountain	1,072	14.7%
V (ex CA) - West Coast	6,414	45.0%
V (CA only) - California	0	0.0%
U.S. Totals	**46,929**	**18.9%**

Notes: • California has established its own gasoline composition standards that take effect statewide in 1996. Thus, PAD District V, California nonattainment cities are not expected to opt-in to the Federal reformulated gasoline program and are not included in this table. • Ozone attainment areas that are within an ozone transport region may also opt-in to the program. However, these areas are not included in this table.

Source: Refer to Table 3 and *Federal Register*, Vol. 56, No. 215 (Washington, DC, November 6, 1991), pp. 56694-56858.

aromatics and constitutes about 27 percent of the total gasoline pool.

FCC's and Reformers are operated to produce high-octane blendstocks for the gasoline pool. Changing operating conditions (e.g., temperature, pressure, reactor space velocity, catalyst type, etc.) can lower benzene and aromatics production. The 1992 NPC survey respondents reported that about 310,000 barrels per day of high pressure catalytic reforming units will be converted to low pressure or continuous catalyst regeneration units.[15]

Table 5. Summer Conventional and Reformulated Gasoline Calculated Btu Content
(Thousand Barrels per Day)

Component	Net (lower) Heating Value (Btu per Gallon)	Gasoline: Conventional Gasoline	Gasoline: Reformulated with MTBE	Gasoline: Reformulated with Ethanol
Saturates and Olefins	110,860	63.6%	62.8%	70.5%
Normal Butane	93,200	4.0%	2.0%	0.0%
Aromatics	125,600	30.1%	24.0%	24.0%
MTBE	93,500	1.2%	11.2%	-
Ethanol	76,000	1.1%	-	5.5%
Calculated Btu Content per Gallon		114,000	112,100	112,480

Notes: • Btu content of aromatics is a simple average of values for benzene, toluene, m-xylene, and p-xylene. • Btu content of saturates and olefins is an assumed value that yields a conventional gasoline Btu content of 114,000 Btu per gallon.

Sources: American Petroleum Institute, *Alcohols and Ethers, A Technical Assessment of Their Applications as Fuel and Fuel Components*, Publication 4261, Second Edition (Washington, DC, July 1988), p. 2; Phillips Petroleum Company, *Reference Data for Hydrocarbons and Petro-Sulfur Compounds* (Bartlesville, OK).

Table 6. Estimated 1990 U.S. Gasoline Pool Composition
(Thousand Barrels per Day)

Blendstock	Gasoline Pool Composition (percent)	RVP (psi)	Benzene (volume percent)	Aromatics (volume percent)
FCC Gasoline	40.6 %	7.0	1.0 %	28.7 %
Reformate	27.0 %	4.3	3.0 %	66.1 %
Alkylate	12.6 %	7.5	0.0 %	0.5 %
Straight-run Naphtha	4.3 %	11.9	1.7 %	7.2 %
Normal Butane	3.0 %	55.0	0.0 %	0.0 %
MTBE	1.1 %	10.0	0.0 %	0.0 %
Ethanol	1.0 %	18.0	0.0 %	0.0 %
Other	10.4 %	14.0	0.6 %	5.9 %
Average Gasoline	100 %	8.8	1.3 %	30.4 %

Note: Normal butane pool composition is an assumed value.

Sources: MTBE and ethanol volume contributions from Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(92/02) (Washington, DC, February 1992), p. *xliv*; others are from National Petroleum Council, *U.S. Petroleum Refining*, Volume VI (Washington, DC, August 1993), pp. N242-N244.

Changing operating conditions of existing equipment will not fully satisfy the new gasoline quality targets at many refineries, and they are implementing other capital intensive options to meet the benzene and aromatics restrictions:

- Prefractionate Reformer feed to remove benzene precursors (e.g., cyclic compounds like methyl cyclopentane and cyclohexane). The benzene precursors in the Reformer feed contribute about 70 to 80 percent of the benzene entering the gasoline pool. Removal of most C_6 benzene precursors may lower reformate benzene concentration to as low as 1.0−1.5 percent.[16] The fractionated C_5's and C_6's may then be blended into gasoline or isomerized to increase octane and then blended into gasoline.

- Fractionate the Reformer product and hydrogenate the benzene-rich fraction to convert benzene to methyl cyclopentane and cyclohexane, or extract benzene and other aromatics for sale into the petrochemicals market.

- Distill out the heavy aromatics fraction from FCC gasoline for further processing such as hydrocracking.

Respondents to the 1992 NPC survey reported plans to install by 1995 an additional 1,193,000 barrels per day of secondary gasoline fractionation capacity, 142,000 barrels per day of pentane/hexane isomerization capacity, 33,000 barrels per day of light naphtha/gasoline aromatics saturation capacity, and 24,000 barrels per day of additional aromatics extraction capacity.[17]

These options to control benzene and aromatics production may also require new sources of hydrogen. For example, lowering reformer severity to reduce aromatics content also decreases hydrogen production. Investment in additional hydrogen production plants (e.g., steam reforming of methane) will be necessary in some refineries. NPC survey respondents anticipated a 22-percent increase in on-purpose refinery hydrogen production capacity (most of this capacity expansion is required for production of low-sulfur on-highway diesel fuel oil).[18]

RVP Reduction: The new reformulated gasoline summer RVP regulations continue reductions that began in 1989 with a two-phase RVP reduction program promulgated by the EPA (Table 7).[19] Gasoline vapor pressure control is relatively straightforward. The primary methods for lowering RVP are reducing the volume of normal butane (a liquefied petroleum gas) blended into gasoline or increasing the volume of normal butane rejected from gasoline through distillation. About 2 gallons of normal butane have to be removed from 100 gallons of gasoline to reduce gasoline RVP by 1 psi based on a simple linear blending calculation.[20] Butane removed from the gasoline pool can be inventoried for winter gasoline blending, converted to isobutane and then to isobutylene for MTBE production, or sold into the petrochemicals market.

RVP reduction in reformulated gasoline is made somewhat more difficult because blending ethanol or MTBE yields RVP increases (Table 8). Some additional RVP reduction may be obtained by also removing C_4 and C_5 olefins (e.g., butylenes and amylenes) from the gasoline pool. Alkylation is a primary means of converting light olefins to heavier gasoline blendstocks. NPC survey respondents reported plans for an additional 79,000 barrels per day of alkylation capacity.[21] Isobutylene and isoamylene may also be converted to MTBE/ETBE and TAME, respectively.

Reformulated Gasoline Imports: Gasoline imports averaged 197,000 barrels per day in 1993, with Brazil, Canada, Saudi Arabia, and Venezuela providing over 71 percent of the total.[22] Over 90 percent of U.S. gasoline imports are into PAD District I, the East Coast, which is also the largest market for reformulated gasoline.

Imported gasoline presents a unique problem because the EPA would be unable to enforce the anti-dumping regulations on foreign refiners. Foreign refiners may realize a cost advantage by dumping benzene and aromatics extracted from reformulated gasoline into their conventional gasoline sold in their own markets. The cost advantage under the simple model is limited to benzene and aromatics and is likely to be small. The advantage under the complex model should be larger because of the ability to trade-off reformulated gasoline characteristics, such as aromatics for oxygen content.

Both domestic refiners and importers must establish individual 1990 anti-dumping baselines for conventional gasoline (and levels for sulfur, olefins, and T_{90} in reformulated gasoline under the simple model) if the necessary actual 1990 gasoline quality data are available. If the actual 1990 data are not available to domestic refiners, the next best available data from production after 1990 are used to establish a baseline. Importers, however, are not allowed to revert to more recent data. If actual 1990 gasoline quality data are not available, importers (and blenders) must use the

Table 7. Motor Gasoline Summer Volatility Regulations
(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	Reformulated After January 1, 1995
Ozone Attainment Areas					
Northern United States	C	11.5	[a]10.5	9.0	9.0
Southern United States	B	10.5	9.5	9.0	9.0
Southern United States	A	9.0	9.0	9.0	9.0
Ozone Nonattainment Areas					
Northern United States	C	11.5	[a]10.5	9.0	8.1
Southern United States	B	10.5	9.5	7.8	7.2
Southern United States	A	9.0	9.0	7.8	7.2

[a]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 1989.

Notes: Regulations apply to the summer months of May 1 through September 15.

Table 8. Reid Vapor Pressure of Various Alcohol/Ether Gasoline Blends
(Pounds per Square Inch)

Percent of Gasoline	Percent of Alcohol/Ether	Blending Agent		
		Ethanol	ETBE	MTBE
100	0	9.00	9.00	9.00
95	5	10.10	8.80	9.40
90	10	10.00	8.60	9.20
85	15	9.90	8.30	9.10

Source: U.S. Department of Energy Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 11*, ORNL-6649 (Oak Ridge, TN, January 1991), p. 4-4.

CAAA90 statutory baseline gasoline, which approximates the U.S. national average quality for gasoline sold in 1990. However, if an importer brought 75 percent or more of the 1990 gasoline production from one refinery into the U.S., it must establish an individual baseline as if it were a domestic refinery.

Oxygenate Supply and Demand

EIA projects that demand for oxygenates (ethanol, MTBE, ETBE, and TAME) will increase from an average 319,100 barrels per day of MTBE-equivalent volume in 1993 to an average 480,000 barrels per day in 1995. The increase in oxygenate demand for reformulated gasoline will be partially offset by expected declines in ethanol blended into gasohol and MTBE blended into conventional gasoline. Oxygenate supply in 1995 will come primarily from MTBE and fuel ethanol domestic production, supplemented by small volumes of TAME and ETBE production, MTBE imports, and MTBE inventory draw.

Oxygenate Demand: Total oxygenate demand is based on projections of reformulated and oxygenated gasoline demand plus continued demand for ethanol and MTBE as blendstocks in conventional gasoline. EIA expects the demand for oxygenates in reformulated and oxygenated gasoline to average 373,000 barrels per day of MTBE-equivalent volume in 1995. Continued demand for ethanol in gasohol blending and MTBE as a gasoline octane blendstock increases total projected oxygenate demand in 1995 to an average 480,000 barrels per day of MTBE-equivalent volume (Figure 1).

The oxygenate content of reformulated gasoline is assumed to average 2.1 weight percent. The oxygenated gasoline program (initiated on November 1, 1992) will require reformulated gasoline markets in Baltimore, New York City, Philadelphia, Washington, DC, and the State of New Jersey to increase the oxygenate level to a minimum 2.7 weight percent (2.8 percent assumed average) during certain winter months. An additional 21 cities participate in the oxygenated gasoline program and will continue to require 2.7 weight percent oxygenates, except cities in California (2.1 weight percent assumed) and Tucson, Arizona (1.9 percent assumed).[23] EIA projects 1995 average oxygenate demands (in MTBE-equivalent volume) in these markets as follows:

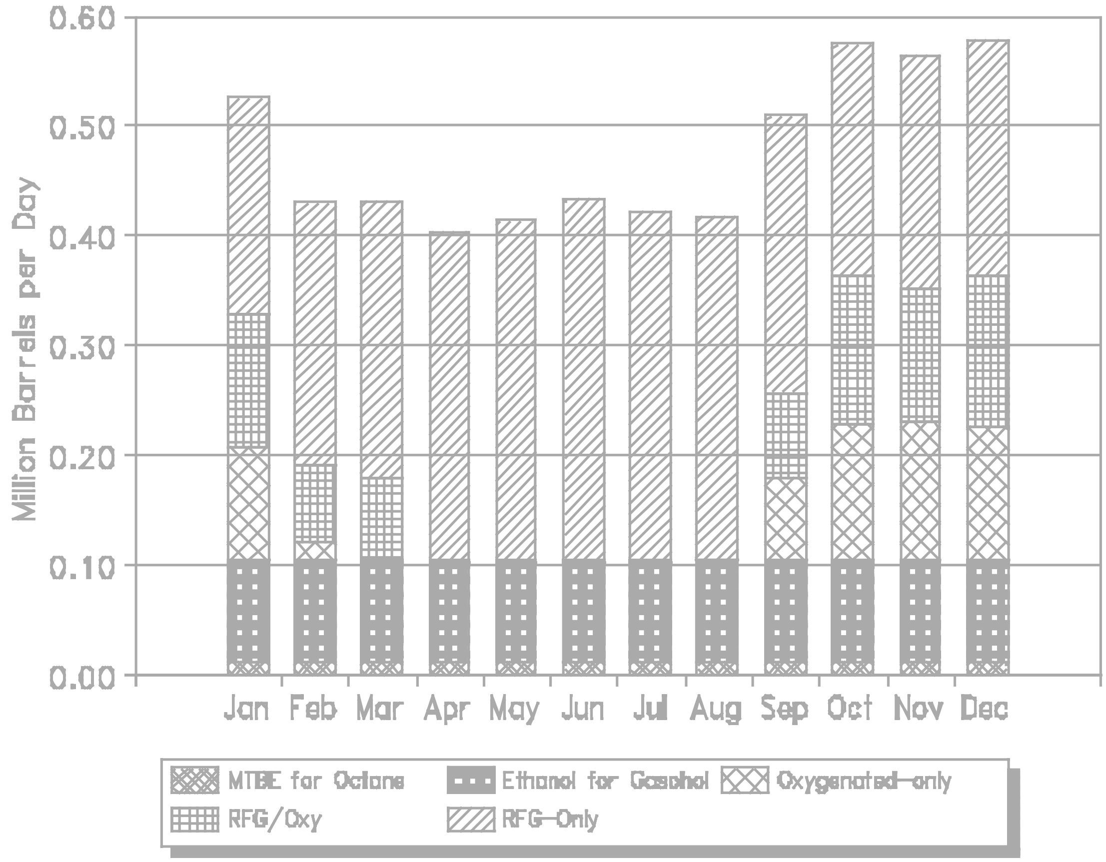
Market	Gasoline Barrels per Day
Reformulated-only	263,000
Reformulated/Oxygenated	62,000
Oxygenated-only	48,000
Total Nonattainment area oxygenate demand . .	373,000

Ethanol will continue to be used for gasohol in areas that do not require reformulated or oxygenated gasoline. Over 76 percent of all gasohol is sold in the Midwestern States (PAD District II), because of proximity to ethanol producers and State tax incentives for gasohol.[24] Ethanol demand averaged about 68,000 barrels per day during the second and third quarters of 1993 (between the first and second oxygenated gasoline seasons).[25] This historical baseline ethanol demand for gasohol blending is lowered to account for reformulated and oxygenated gasoline market shares in States that reported gasohol sales. About 120,000 barrels per day of gasohol (12,000 barrels per day of contained ethanol) may be replaced by reformulated or oxygenated gasoline.

Because of the expected improved balance between total oxygenate supply and demand in 1995, stronger oxygenate prices should also lead to reduced gasohol sales in States that do not offer State tax credits or in-state ethanol production facilities. About 20,000 barrels per day of ethanol was sold into States without tax credits for gasohol blending in 1992. This forecast assumes an additional 10,000 barrels per day of ethanol will be redirected from gasohol sales to reformulated gasoline markets. The continued demand for ethanol in gasohol sales is then projected to average 46,000 barrels per day, or 93,000 barrels per day of MTBE-equivalent volume.

MTBE may also continue to be used as an octane blend component in gasoline sold in areas that do not require reformulated or oxygenated gasoline. MTBE demand averaged about 88,000 barrels per day during the second quarter 1993.[26] Because of excess MTBE production capacity during 1993, MTBE selling prices were generally determined by its octane value and did not include any oxygenate price premium. Thus, there was limited incentive to restrain MTBE use during the year. Continued MTBE demand as an octane blendstock is assumed to be the balancing item between

Figure 1. Projected 1995 Oxygenate Demand (MTBE-Equivalent Volume)



Sources: Details provided in Figure Reference section, p. 45.

the 1995 oxygenate supply and demand forecasts. MTBE use as an octane blendstock is expected to average about 14,000 barrels per day in 1995. This small volume of MTBE octane blending highlights the potential tightness in the oxygenate markets.

Oxygenate Supply: Total oxygenate supply for gasoline blending in 1993 was almost evenly split between MTBE and fuel ethanol (on an MTBE-equivalent volume basis). MTBE production averaged 136 thousand barrels per day with an additional 15 thousand barrels per day net imports and 11 thousand barrels per day inventory drawdown. Ethanol production averaged 152 thousand barrels per day of MTBE-equivalent volume with an inventory build of 1.7 thousand barrels per day and no net imports.[27] Total oxygenate supply is projected to increase to an average 480 thousand barrels per day in 1995, primarily through new domestic MTBE and TAME production capacity and higher MTBE imports.

Domestic Production: Production capacity for both MTBE and ethanol has steadily increased since the early 1980's. Federal and local tax incentives for blending renewable fuel ethanol into gasoline and the continued growing demand for gasoline octane blendstocks contributed to steady increases in demand for ethanol and MTBE. The new Federal oxygenated and reformulated gasoline programs have stimulated a dramatic increase in MTBE production capacity within the last few years (Table 9). On the other hand, ethanol shipping costs, gasohol nonfungibility with gasoline, and limited State tax incentives have contributed to restrained growth in ethanol production capacity.

Table 9. Oxygenate Production Capacity and 1995 Production Forecast
(Barrels per Calendar Day)

	MTBE	TAME	ETBE	Ethanol
Capacity History				
January 1, 1991	122,500	547	0	82,643
January 1, 1992	135,090	3,689	0	93,498
January 1, 1993	182,153	5,000	815	87,053
January 1, 1994	226,703	14,500	815	90,672
Capacity Projections				
January 1, 1995	269,553	20,640	815	103,718
January 1, 1996	282,053	24,700	815	106,718
Average 1995 Capacity	275,803	22,670	815	105,218
Capacity Utilization Factor	0.83	0.70	0.70	0.85
Projected 1995 Production	228,916	15,870	570	89,435
Volume Correction Factor for MTBE-Equivalent Volume	1.00	0.89	0.88	2.03
Projected 1995 Production MTBE-Equivalent Volume	228,916	14,123	502	181,554

Source: • Capacity history and projections for January 1, 1995, from Energy Information Administration, *Petroleum Supply Annual 1993*, Volume 1, DOE/EIA-0340(93)/1 (Washington, DC, June 1994). • Capacity projections for January 1, 1996 based on plants scheduled to start-up in 1995; Information Resources, Inc., "Oxygenated Fuels Industry Gears Up For Reformulated Gasoline," *Fuel Reformulation* (Denver, CO, March/April 1994), pp. 48-56. • Capacity utilization factors from National Petroleum Council, *U.S. Petroleum Refining*, Volume I (Washington, DC, August 1993) p. 147; Ethanol plant utilization factor adjusted for observed 1993 operations.

Projected oxygenate production capacities are based on data collected by the Energy Information Administration (Form EIA-822). Limited feedstock supply, plant maintenance, and variable market conditions contribute to less than full capacity utilization. Consequently, domestic production of oxygenates, MTBE, TAME, and ethanol is expected to average about 425 thousand barrels per day in MTBE-equivalent volume in 1995 (Table 9).

Imports: MTBE imports will also represent a significant source of oxygenates and will make up some of the projected difference between total demand and domestic production. Ethanol and ETBE imports are not expected to significantly contribute to oxygenate supply because of the steep tariffs on these products (Table 10). MTBE net imports averaged 15,000 barrels per day in 1993, primarily from world-scale MTBE plants (over 10,000 barrels per day capacity) in Canada, Saudi Arabia, and Venezuela.[28] Foreign MTBE plant capacity grew by 26,900 barrels per day in 1993, and is expected to grow by 60,000 barrels per day in 1994 and 39,500 barrels per day in 1995.[29] EIA assumes MTBE net imports in 1995 will increase to 45,000 barrels per day.

Inventories: The reformulated gasoline program will alter the role of inventories in meeting oxygenate supply needs. The CAAA90 oxygenated gasoline program, which began in November 1992, introduced a highly seasonal (winter only) demand for oxygenates. The reformulated gasoline program will reduce the role of inventories in meeting winter peak oxygenate demand that was observed during the first two oxygenated gasoline seasons. MTBE inventory draw contributed an average 11,134 barrels per day to oxygenate supply in 1993. MTBE inventories are expected to build during the second half of 1994 to satisfy reformulated and oxygenated gasoline demand for oxygenates during 1995. Although the potential for 1995 oxygenate supply from inventory is highly uncertain, an average 10,000 barrels per day is assumed, for a total inventory drawdown of 3.65 million barrels.

Table 10. Import Tariffs on Fuel Oxygenates, as of January 1, 1994

Product	General	NAFTA Canada	NAFTA Mexico	Generalized System of Preferences	Caribbean Basin
MTBE/TAME	5.6 %	Free	Free	Free	Free
ETBE	$0.227/gallon	Free	$0.201/gallon	Free	Free
Fuel Ethanol	$0.54/gallon	$0.238/gallon	$0.484/gallon	$0.54/gallon	Free

Notes: NAFTA refers to the North American Free Trade Agreement. Generalized System of Preferences includes countries such as Argentina, Bahrain, Malaysia, and Venezuela. The Caribbean Basin [Economic Recovery Act] includes Trinidad.

Source: U.S. International Trade Commission, *Harmonized Tariff Schedules of the United States* (Washington, DC, December 15, 1993); MTBE/TAME product code 2909.19.10; fuel ethanol product code 9901.00.50; ETBE product code 9901.00.52.

Renewable Oxygenate Standard: The EPA's proposal to mandate use of renewable fuel oxygenates in a minimum portion of the reformulated gasoline pool may provide additional incentive to shift ethanol out of the Midwest gasohol markets to replace MTBE either directly in reformulated gasoline blends or indirectly through conversion of MTBE production facilities to ETBE production. Ethanol production in 1995 is projected to average about 89 thousand barrels per day (Table 9). An average of about 24,000 barrels per day of ethanol will be required in 1995 to meet a minimum 15 percent reformulated gasoline oxygenate market share under the Renewable Oxygenate Standard.

Reformulated Gasoline Costs

The new requirements for oxygenates and reductions in RVP, benzene, and aromatics content in reformulated gasoline will lead to production cost increases that may be passed through as a price premium over conventional gasoline.

Most published estimates of reformulated gasoline production costs are derived from linear programming (LP) models. The EPA's LP model generates a price premium for Phase I reformulated gasoline of about 4 cents per gallon over the cost of conventional gasoline.[30] This price premium includes fuel economy effects resulting from the change in reformulated gasoline's heat content due to the addition of oxygenates and reduction in RVP. The EPA's LP model estimate of the average refinery cost for producing reformulated gasoline (excluding the average cost of fuel economy effects of 1.4 cents per gallon) is about 2.6 cents per gallon.

The NPC's LP model estimate of the added refining cost to produce Phase I summer reformulated gasoline is about 5.5 to 6.0 cents per gallon. This does not include fuel economy effects.[31] In its base case, the NPC assumed reformulated gasoline would be supplied only to the 9 mandated cities with 10 percent spillover (about 27 percent of total gasoline demand). With full opt-in (reformulated gasoline representing about 65 percent of total gasoline demand), the average refining cost rises by only 0.5 cents.

The differences in LP model results arise not only because of different model structures and assumptions, but also because a price premium reported may represent either an average cost (based on the LP model "objective function value") or a marginal cost (corresponding to an LP model "shadow price"). In this forecast, EIA uses observed market price premiums for oxygenate additions under the oxygenated gasoline program and summer RVP reductions in some gasoline markets to estimate the refiner's marginal cost for producing reformulated gasoline. Because the benzene and aromatics restrictions are new, reported LP model results are used to estimate the cost of this part of the reformulated gasoline program. By these analyses, EIA estimates that the added cost to produce reformulated gasoline will be 3.9 cents per gallon in summer and 3.5 cents per gallon in winter:

Cents per Gallon	
3.00	Blend oxygenates to 2.0 percent oxygen by weight.
0.40	Remove high vapor pressure components from gasoline to meet summer RVP specifications.
0.50	Reduce level of benzene and other aromatics.
3.90	Summer reformulated gasoline cost.
3.50	Winter reformulated gasoline cost. (Does not include cost of RVP reduction).

Oxygenate Blending: An estimated price premium for oxygenate blending may be derived from the observed premium for oxygenated gasoline during the last two winter carbon monoxide control seasons (Table 11). The wholesale spot price premium for oxygenated gasoline over conventional gasoline is assumed to recover to 4.0 cents per gallon in 1995. The significant increase in demand for oxygenates in reformulated gasoline is assumed to eliminate the over supply of oxygenates that contributed to weakness in the oxygenates markets. Since the required oxygenate level in reformulated gasoline is only 74 percent of the level of oxygenated gasoline (2.0 weight percent versus 2.7 weight percent), oxygenate blending is assumed to contribute 3.0 cents per gallon to the reformulated gasoline price premium.

RVP Reduction: The market price premium for reducing RVP depends on the price differential between gasoline and normal butane. The market price premium for 7.8 RVP gasoline relative to 9.0 RVP gasoline during the summer of 1993 was about 4 percent of the price difference between 7.8 RVP gasoline and normal butane, or about 0.66 cents per gallon per psi reduction (Table 12). This observed market price premium is almost 50 percent greater than expected from a simple linear blend calculation that corrects for octane differences.[32] One reason for the additional price premium for low RVP gasoline is that 7.8 RVP material is only required in ozone nonattainment areas in the Southern States, which represents only about 18 percent of the total gasoline market. The small market share and restrictive distribution requirements may contribute to the higher observed market price premium. The reformulated gasoline regulations require a 0.9-psi reduction in RVP in Northern States ozone nonattainment areas (EPA VOC Control Region 2) and a 0.6-psi reduction in southern areas (EPA Region 1) during the summer months. The average reformulated gasoline RVP reduction is about 0.8 psi. The EPA estimated the refinery cost to reduce RVP (including capital recovery cost) was about 0.4 cents per gallon per psi reduction.[33] This EPA estimate is consistent with the observed market price premium in June and July of 1993 when demand for low-RVP gasoline was at its highest. The average cost for reducing RVP to meet reformulated gasoline requirements during the summer

Table 11. Market Price Premium for Unleaded Oxygenated Gasoline
(Cents per Gallon)

	New York Harbor Cargo Spot Price			Gulf Coast Waterborne Spot Price		
Date	Conventional	Oxygenated	Difference	Conventional	Oxygenated	Difference
October 1992	60.04	63.64	3.60	59.42	62.77	3.35
November 1992	56.74	60.79	4.05	53.84	56.98	3.14
December 1992	52.99	57.16	4.17	50.89	54.66	3.77
January 1993	53.07	56.96	3.89	51.83	55.11	3.28
February 1993	52.74	56.53	3.79	51.46	54.38	2.92
March 1993	53.84	57.40	3.56	56.51	58.75	2.24
October 1993	50.34	53.04	2.70	48.32	50.79	2.47
November 1993	44.32	47.40	3.08	42.31	44.82	2.51
December 1993	37.99	41.32	3.33	36.20	40.54	4.34
January 1994	42.44	44.96	2.52	41.90	45.44	3.54
February 1994	44.06	46.88	2.92	43.84	46.79	2.95

Source: McGraw-Hill, Inc., *Platt's Oilgram Price Report*, Price Average Annual Supplement, February 1994, Vol. 72, No. 59 (New York, NY, March 25, 1994), and earlier issues.

Table 12. Market Price Premium for Low Vapor Pressure (RVP) Gasoline
(Cents per Gallon)

	Gulf Coast Waterborne Spot Price			
	9.0 RVP	7.8 RVP	Difference	Mont Belvieu 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

Source: McGraw-Hill, Inc., *Platt's Oilgram Price Report*, Price Average Supplement, August 1993, Vol. 71, No. 234 (New York, NY, December 3, 1993), and earlier issues.

months is estimated to be about 0.40 cents per gallon of reformulated gasoline (0.8 psi times 0.5 cents / gallon / psi reduction).

Aromatics Reduction: The average level of aromatics in regular unleaded gasoline is about 32 volume percent in the summer and 28 volume percent during the winter. Benzene concentrations average 1.6 volume percent during the summer and 1.5 percent during the winter.[34] Under the new regulations, benzene must be reduced to 1.0 percent by volume or lower. The required aromatics reduction is determined by the emissions model for TAP reduction and is dependent on the fuel's RVP, benzene concentration, and the level and type of oxygenate. Reductions in aromatics of 2 to 4 volume percent are expected.

The EPA estimated the cost to reduce aromatics from 30 percent to 28 percent by volume to be 0.0664 cents per gallon per percent reduction. For a further reduction from 28 percent down to 24 percent the cost rose to 0.305 cents per gallon per percent reduction.[35] EIA assumes an average cost of benzene and the aromatics reduction of 0.50 cents per gallon.

Glossary

Alcohol: The family name of a group of organic chemical compounds composed of carbon, hydrogen, and oxygen. The series of molecules vary in chain length and are composed of a hydrogen, plus a hydroxyl group; CH_3-$(CH_2)_n$-OH (e.g., methanol, ethanol, and tertiary butyl alcohol).

Aromatics: Hydrocarbons characterized by unsaturated ring structures of carbon atoms. Commercial petroleum aromatics are benzene, toluene, and xylene (BTX).

Catalytic Reforming: A refining process using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules, thereby converting paraffinic and naphthenic type hydrocarbons (e.g., low-octane gasoline boiling range fractions) into petrochemical feedstocks and higher octane stocks suitable for blending into finished gasoline.

ETBE (Ethyl Tertiary Butyl Ether), $(CH_3)_3COCO_2H_5$: An oxygenate blend stock formed by the catalytic etherification of isobutylene with ethanol.

Ether: A generic term applied to a group of organic compounds composed of carbon, hydrogen, and oxygen, characterized by an oxygen atom attached to two carbon atoms (e.g., methyl tertiary butyl ether).

Ethanol (Fuel), C_2H_5OH: An anhydrous denatured aliphatic alcohol intended for gasoline blending. See **Oxygenates**.

Fluid Catalytic Cracking: The refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil.

Isobutylene, C_4H_8: An olefinic compound recovered from refinery processes or petrochemical processes.

Methanol, CH_3OH: A light, volatile alcohol eligible for gasoline blending. See **Oxygenates**.

MTBE (Methyl tertiary Butyl Ether), $(CH_3)_3COCH_3$: An ether, intended for gasoline blending, formed by the catalytic etherification of isobutylene with methanol. See **Oxygenates**.

Oxygenates: Any substance which, when added to gasoline, increases the amount of oxygen in that gasoline blend. Through a series of waivers and interpretive rules, the Environmental Protection Agency (EPA) has determined the allowable limits for oxygenates in unleaded gasoline. The "Substantially Similar" Interpretive Rules (56 FR [February 11, 1991]) allows blends of aliphatic ethers and aliphatic alcohols, provided the oxygen content does not exceed certain limits specified for each blending component.

Oxygenated Gasoline: Motor gasoline which contains no less than 2.7 percent oxygen by weight in the form of blended oxygenates.

PAD (Petroleum Administration for Defense) District.

PAD District I.

Subdistrict IA. Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont.

Subdistrict IB. Delaware, District of Columbia, Maryland, New Jersey, New York, Pennsylvania.

Subdistrict IC. Florida, Georgia, North Carolina, South Carolina, Virginia, West Virginia.

PAD District II.

Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, South Dakota, Ohio, Oklahoma, Tennessee, Wisconsin.

PAD District III.

Alabama, Arkansas, Louisiana, Mississippi, New Mexico, Texas, Federal Offshore Gulf.

PAD District IV.

Colorado, Idaho, Montana, Utah, Wyoming.

PAD District V.

Alaska (North Slope and Other Mainland), Arizona, California, Hawaii, Nevada, Oregon, Washington, Federal Offshore California.

TAME (Tertiary Amyl Methyl Ether), $(CH_3)_2(C_2H_5)COCH_3$: An ether, intended for gasoline blending, formed by the catalytic etherification of isoamylene with methanol. See **Oxygenates**.

Notes: Chapter 2

[1]Public Law 101-549, Section 211(k), U.S.C. 42, "Clean Air Act Amendments of 1990," enacted on November 15, 1990. Final rule published in *Federal Register*, Vol. 59, No. 32 (Washington, DC, February 16, 1994), p. 7716. VOC exclude methane and ethane. TAP are defined as the total mass emissions of benzene, 1,3-butadiene, polycyclic organic matter, formaldehyde, and acetaldehyde.

[2]Energy Information Administration, *Short-Term Energy Outlook*, Second Quarter 1994, DOE/EIA-0202(94/2Q) (Washington, DC, May 1994).

[3]*Federal Register*, Vol. 58, No. 246 (Washington, DC, December 27, 1993), p. 68343. The final rule was announced by EPA on June 30, 1994.

[4]Reformulated gasoline requirements apply at facilities upstream of retail outlets beginning on December 1, 1994.

[5]*Federal Register*, Vol. 58, No. 37 (Washington, DC, February 26, 1993), pp. 11745-11750. The T_{50} and T_{90} specifications refer to the temperatures at which 50 percent and 90 percent of the fuel vaporizes, respectively.

[6]National Petroleum Council, *U.S. Petroleum Refining*, Volume VI (Washington, DC, August 1993), pp. N238-N240. Response to the NPC survey was as high as 154 of 197 refineries, which represented almost 95 percent of 1990 U.S. refinery inputs. Not all respondents answered all survey items.

[7]*Federal Register*, Vol. 59, No. 32 (Washington, DC, February 16, 1994), pp. 7807-7808 and 7851-7852.

[8]Hart Publications, Inc., "As SIP Deadline Nears, States Consider Various Options," *Oxy-Fuel News* (November 8, 1993), pp. 8-11.

[9]Energy Information Administration, "The Economics of the Clean Air Act Amendments of 1990: Review of the 1992-1993 Oxygenated Motor Gasoline Season," *Petroleum Supply Monthly*, DOE/EIA-0109(93/07) (Washington, DC, July 1993), pp. xiii-xxv.

[10]Respondents to the 1992 NPC refinery survey anticipate a spillover rate of under 5 percent; National Petroleum Council, *U.S. Petroleum Refining*, Volume VI (Washington, DC, August 1993), p. N261. The EPA assumed a 10-percent spillover rate in its regulatory impact analysis; Environmental Protection Agency, *Final Regulatory Impact Analysis for Reformulated Gasoline* (Washington, DC, December 13, 1993), p. 334.

[11]Environmental Protection Agency, *Final Regulatory Impact Analysis for Reformulated Gasoline* (December 13, 1993), pp. 344-347.

[12]Elasticity of gasoline demand with respect to price is calculated by dividing the percentage difference in gasoline demand from the *Short-Term Energy Outlook's* low oil price and high oil price cases by the percentage difference in gasoline prices in those two price cases. The elasticity based on the second-quarter 1994 *Outlook* is 11.0 percent for 1995 average gasoline demand.

[13]Respondents to the NPC survey estimated total capital expenditures directly related to reformulated gasoline would total $3,979 million. National Petroleum Council, *U.S. Petroleum Refining*, Volume VI (Washington, DC, August 1993), p. N255.

[14]Environmental Protection Agency, *Final Regulatory Impact Analysis for Reformulated Gasoline* (December 13, 1993), p. 479, and Testimony of Susan F. Tierney, Assistant Secretary for Policy, Planning and Program Evaluation, U.S. Department of Energy, before the Committee on Energy and Commerce Subcommittee on Oversight and Investigations, U.S. House of Representatives, June 22, 1994.

[15]National Petroleum Council, *U.S. Petroleum Refining*, Volume I (Washington, DC, August 1993), p. 236.

[16]PennWell Publishing Co., "Refiners Have Several Options for Reducing Gasoline Benzene," *Oil and Gas Journal* (September 13, 1993), pp. 63-69.

[17]National Petroleum Council, *U.S. Petroleum Refining*, Volume VI (Washington, DC, August 1993), pp. N210-N231.

[18]National Petroleum Council, *U.S. Petroleum Refining*, Volume VI (Washington, DC, August 1993), p. N230.

[19]Phase I gasoline volatility regulation announced by Environmental Protection Agency in *Federal Register*, Vol. 54, No. 54 (Washington, DC, March 22, 1989) p. 11868. Phase II volatility regulation announced in *Federal Register*, Vol. 55, No. 112 (Washington, DC, June 11, 1990), p. 23658.

[20]Internal calculation based on lowering 9.0 RVP vapor pressure finished motor gasoline to 8.0 RVP by removing 55-60 RVP normal butane.

[21]National Petroleum Council, *U.S. Petroleum Refining*, Volume VI (Washington, DC, August 1993), p. N226.

[22]Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(94/02) (Washington, DC, February 1994), p. 82. Import figures are adjusted to exclude the Virgin Islands.

[23]For a review of the oxygenated gasoline forecast procedure refer to Energy Information Administration, "Demand, Supply, and Price Outlook for Oxygenated Gasoline, Winter 1992-1993," *Monthly Energy Review*, DOE/EIA-0035(92/08), (Washington, DC, August 1992), p. 7.

[24]Federal Highway Administration, *Highway Statistics 1992*, FHWA-93-023 (Washington, DC, 1993), p. 11. States with reformulated and/or oxygenated gasoline markets that reported gasohol sales include California, Colorado, Connecticut, Illinois, Indiana, Kentucky, Minnesota, Montana, Nevada, Oregon, Texas, Utah, Virginia, Washington, and Wisconsin.

[25]Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(94/01), (Washington, DC, January 1994), p. 148.

[26]Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(94/01), (Washington, DC, January 1994), p. 149.

[27]Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(94/01) (Washington, DC, January 1994), pp. 148-149. MTBE imports from Energy Information Limited, "U.S. MTBE Imports Remain Strong While Stocks Rebuild With End of Oxy Season," *Oil Market Listener* (San Francisco, CA, April 6, 1994).

[28]Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(94/01) (Washington, DC, January 1994), pp. 148-149. MTBE imports from Energy Information Limited, "U.S. MTBE Imports Remain Strong While Stocks Rebuild With End of Oxy Season," *Oil Market Listener* (San Francisco, CA, April 6, 1994).

[29]Information Resources, Inc., "Oxygenated Fuels Industry Gears Up For Reformulated Gasoline," *Fuel Reformulation* (Denver, CO, March / April 1994), pp. 48-56.

[30]Environmental Protection Agency, *Final Regulatory Impact Analysis for Reformulated Gasoline* (Washington, DC, December 13, 1993), p. 306.

[31]National Petroleum Council, *U.S. Petroleum Refining,* Volume I (Washington, DC, August 1993), p. 235.

[32]Internal calculation based on 2 volume percent reduction in gasoline normal butane (Nc_4) content for each 1 psi reduction in RVP and Nc_4 road octane (R+M) / 2 = 92.1:

0.976 (7.8 RVP gasoline price) + 0.024 (Nc_4 price) = 9.0 RVP gasoline price - octane credit

or, 7.8 RVP price - 9.0 RVP price = 0.024 (7.8 RVP price - Nc_4 price) - octane credit

[33]Environmental Protection Agency, *Final Regulatory Impact Analysis for Reformulated Gasoline* (Washington, DC, December 13, 1993), p. 348.

[34]National Institute for Petroleum and Energy Research, *Motor Gasoline, Winter 1991-92,* NIPER-175 PPS 92 / 3 (Bartlesville, OK, June 1992), and *Motor Gasoline, Summer 1992,* NIPER-178 PPS 93 / 1 (Bartlesville, OK, January 1993).

[35]Environmental Protection Agency, *Final Regulatory Impact Analysis for Reformulated Gasoline* (Washington, DC, December 13, 1993), p. 403.

3. Comparison of EIA and Other Forecasts for 1994 and 1995

This chapter presents a comparison of EIA's energy forecasts for 1994 and 1995 as published in the second quarter 1994 *Short-Term Energy Outlook* and forecasts of several other major U.S. energy forecasters.[36] These forecasts are: DRI/McGraw-Hill (DRI), National Economic Research Associates (NERA), the American Gas Association (AGA) and the Independent Petroleum Association of America (IPAA).[37] 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 1994. Tables 13 and 14 summarize these results. 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 13, the 1993-1994 changes (in both percentage and absolute terms) are based on the 1993 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 1993 at the time of their forecasts. A summary of the 1993 historical data estimates for each forecaster is provided in Table 15.

Summary

All the forecasts were in general agreement on overall economic and energy growth trends for 1994 and 1995. Differences in macroeconomic premises between the forecasts were small. In all but one of the projections (AGA), economic growth, as measured by real gross domestic product (GDP), would accelerate in 1994 from that of the previous year and moderate somewhat in 1995. All of the projections assumed continued low rates of inflation throughout the forecast interval. Projections for total energy demand were consistent with each other but exhibited more variation than those of general economic growth. In all of the projections, total energy growth was less than that of real GDP, resulting in continuing declines in energy intensity. The major source of differences in forecast indicators was world oil prices. EIA and DRI's premises assume year-to- year declines in crude oil prices in 1994 followed by increases in those prices in the following year. AGA and NERA, in contrast, postulated steady increases in crude oil prices throughout the forecast interval. That divergence contributed to differences in relative prices of oil and natural gas and, hence, petroleum and natural gas demand patterns. Natural gas prices, however, were projected to rise in both 1994 and 1995 in all of the forecasts providing such projections. Utility coal price forecasts called for almost no change during the forecast interval.

Despite the divergence in oil price premises, all of the forecasts projected continued declines in crude oil production in 1994. In 1995, oil production is projected to increase only in NERA's forecast in a lagged response to rising crude oil prices during the two-year interval. With the exception of AGA, total petroleum products demand was slated to rise in all of the projections. AGA, in contrast, projected no growth in petroleum products demand in 1994 and only slight growth in the following year. Differences in the price of oil relative to gas as well as the timing of the release of the forecasts accounted for the bulk of the difference in these projections. In 1994, U.S. natural gas

Table 13. Comparison Summary—1994

1994 Projections

production was slated to increase in the EIA and DRI forecasts; IPAA and NERA forecasted slight declines. All of the forecasts, however, projected increases in natural gas production in 1995. Gas demand was projected to rise in all of the forecasts in both years, but at different rates, due to differences in relative prices of oil and gas and economic growth rates. With the exception of DRI, coal production and demand were forecasted to increase in each year. Coal demand in the DRI forecast is projected to decline slightly in 1994 based on assumptions of increased nuclear and hydroelectric power generation compared to 1993.

NOTE: Percentage Change Calculations are Based on 1993 Historical Estimates of Each Forecaster, Which May Differ from Those of EIA.

Table 14. Comparison Summary—1995

	1995 Projections

Table 15. Historical Data Comparison—1993

Forecaster Publication Date	EIA 5/94	DRI 5/94	NERA 4/94	AGA 1/94	IPAA 3/94
Price Assumptions (nominal)					
World Oil Price (dollars per barrel)	16.12	16.17	16.41	16.12	N/A
Petroleum Products (dollars per U.S. gallon)					
Motor Gasoline (retail)	1.17	1.17	1.17	N/A	N/A
Heating Oil (retail)	0.91	1.01	0.91	N/A	N/A
Natural Gas Wellhead (dollars per thousand cubic feet)	1.99	2.01	1.97	N/A	N/A
Coal—utility (dollars per million Btu)	1.38	1.39	N/A	1.38	N/A
Macroeconomic Growth Rates					
Real GDP (percentage change from previous year)	2.9	2.9	2.9	2.7	2.9
Industrial Index (percentage change from previous year)	4.1	4.2	4.1	N/A	4.1
Inflation (percentage change from previous year)	2.5	2.6	2.6	2.6	2.5
Personal Income (percentage change from previous year)	1.9	1.9	N/A	1.8	N/A
Energy Intensity[a]	16.34	16.42	N/A	16.40	16.23
Energy Supply					
Crude Oil Production (million barrels per day)[b]	6.84	6.99	6.84	N/A	6.84
Net Oil Imports (million barrels per day)[c]	7.52	7.57	7.52	N/A	7.52
Total Gas Production (trillion cubic feet)	18.45	18.44	18.43	18.40	18.28
Net Gas Imports (trillion cubic feet)	2.09	2.13	2.12	2.30	2.09
Coal Production (million short tons)	944	947	N/A	N/A	N/A
Net Coal Exports (million short tons)	67	67	N/A	N/A	N/A
Electricity Generation (billion kilowatthours)	2,882	2,899	2,900	2,900	N/A
Energy Demand					
Total Oil Products (million barrels per day)	17.19	17.28	17.17	17.09	17.17
Motor Gasoline (million barrels per day)	7.48	7.51	7.48	7.20	7.48
Jet Fuel (million barrels per day)	1.47	1.47	N/A	1.47	1.47
Distillate (million barrels per day)	3.03	3.09	3.03	2.96	3.03
Residual (million barrels per day)	1.07	1.07	1.07	1.12	1.05
Natural Gas Demand (trillion cubic feet)	20.12	20.10	20.18	20.18	20.19
Coal Demand (million short tons)	928	929	N/A	943	N/A
Electricity Sales (billion kilowatthours)	2,865	2,832	2,870	2,863	N/A
Total Energy Demand (quadrillion Btu)	83.9	84.3	N/A	84.0	85.4
Oil Import Dependence (percent)	43.7	43.8	43.8	N/A	43.8

[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, 1994; DRI/McGraw-Hill, *Energy Review*, Spring-Summer 1994; National Economic Research Associates, *Energy Outlook*, April 1994; American Gas Association—TERA Base Case 1994, January 1994; Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Term Forecast, 1993-2010*, March 1994.

Economic and Price Assumptions

Real gross domestic product (GDP) grew by an estimated 2.9 percent in 1993. With the exception of AGA, in which growth moderates to 2.8 percent, the projections assume accelerated growth in 1994, ranging from 3.1 percent (IPAA) to 3.7 percent (EIA and NERA). In 1995, however, growth in the EIA and DRI forecasts is projected to slow to 1.9 percent. AGA projects growth for that year to match that of 1994 at 2.8 percent. NERA's 1995 forecast calls for a growth rate of 2.9 percent despite robust growth in the previous year. In all the forecasts, industrial production growth in 1994 is projected to outpace that of the overall economy, ranging from 4.1 percent (IPAA) to 5.2 percent (EIA). In 1995, rates of growth of industrial output range from 1.9 percent (EIA) to 3.5 percent (NERA), reflecting divergences in cyclical patterns found in overall economic growth. Inflation, as expressed by the implicit price deflator, range from 2.3 percent (NERA) to 3.1 percent (AGA) for 1994. EIA's projection of 2.4 percent was close to the low end of that range. All of the projections call for a slight uptick in inflation rates for 1995, ranging from 2.5 percent (DRI) to 3.9 percent (AGA). As in the previous year, EIA's projection of 2.6 percent ranks among the low projections.

The major feature distinguishing the forecasts is the world oil price paths. Projections for crude oil prices range from a low of $13.91 per barrel (EIA)—a decline of $2.21 from 1993—to $17.00 per barrel (NERA), an increase of $0.88. All of the forecasts, however, project increases in crude oil prices in 1995. These increases are clustered around an average of $2.00. As a result, EIA's world oil price projection for that year remains the lowest of all the forecasts at $15.90 per barrel, still below the 1993 average. At $19.00 per barrel, NERA is the highest.

Movements in product price projections reflect those of the underlying crude oil costs. For 1994, changes in retail motor gasoline prices ranged from a decline of 2 cents per gallon (EIA) to an increase of 7 cents per gallon (NERA). All of the forecasts providing price projections for 1995 call for similar hikes in motor gasoline prices, ranging from 7 cents per gallon (NERA) to 10 cents per gallon (DRI), reflecting the narrow range of crude oil price increases for that year. Retail heating oil price hikes in 1994 are projected to range from a decline of 2 cents per gallon (DRI) to an increase of 5 cents per gallon (NERA). The EIA projects no change in heating oil prices. In 1995, heating oil prices are projected to increase in all of the forecasts. The increases range from 1 cent per gallon (EIA) to 7 cents per gallon (DRI).

Natural gas wellhead price changes, which are only loosely related to those of crude oil, displayed significant variation in 1994, ranging from an increase of 1 cent per million cubic feet (DRI) to 17 cents per million cubic feet (EIA). In 1995, natural gas prices are projected to increase, with a range of 7 cents per million cubic feet (DRI) to 27 cents per million cubic feet (NERA) despite increases in crude oil costs of a similar magnitude between forecasts. EIA projected an increase of 15 cents per million cubic feet.

Primary Energy Supply

U.S. crude oil production was projected to continue to decline in 1994 in all of the available projections. The decline rates for that year range from 90,000 barrels per day (NERA) to 210,000 barrels per day (EIA). For 1995, changes in production rates from that of the previous year range from a decline of 110,000 barrels per day (DRI) to an *increase* of 70,000 barrels per day (NERA). NERA's production increase is a lagged response to the sizeable escalation in oil prices projected in both forecast years. The EIA projects a decline of 130,000 barrels per day.

In all of the forecasts, a strengthening economy and declines in U.S. production rates in 1994 result in substantial increases in net imports of petroleum. Levels of net imports ranged from 7.77 million barrels per day (DRI)—an increase of 200,000 barrels per day—to 8.13 million barrels per day (NERA), an increase of 610,000 barrels per day. EIA projected net imports to be 7.99 million barrels per day, an increase of 470,000 barrels per day. For 1995, net imports are projected to range from 8.26 million barrels per day (EIA) to 8.40 million barrels per day (NERA). Both of these represent year-to-year increases of 270,000 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, changes in natural gas production for 1994 show little consensus. They range from declines of 0.07 trillion cubic feet (IPAA) to an increase of 0.64 trillion cubic feet (EIA). All of the forecasts project increases for natural gas production in 1995, ranging from 0.10 trillion cubic feet (NERA) to 0.49 trillion cubic feet (DRI). EIA projected an increase of 0.28 trillion cubic feet. Differences in the price of natural gas (or, more specifically, the relative price of natural gas in terms of residual fuel oil) accounted for the bulk of the divergences in production between forecasts. NERA's projected price is $2.40 per million cubic feet; DRI's is $2.09.

Available forecasts for coal production (EIA and DRI) show increases in production in both 1994 and 1995. Much of the year-to-year increase in 1994 results from the strike in 1993 that severely reduced coal production. For 1995, however, continued recovery in export markets as well as domestic demand account for the projected increases in coal production.

Energy Demand

All of the forecasts projected 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 of fuels as well as changes in economic growth rates.

Total petroleum demand for 1994 was projected to increase in all the forecasts, except for AGA, which projected no growth in that category. Both the EIA and NERA projected increases of 500,000 barrels per day, or 2.9 percent. Although DRI projected growth of 460,000 barrels per day, the composition of that growth differed substantially from that of the EIA. EIA projected growth in motor gasoline demand of 110,000 barrels per day; DRI forecasted a decline of 10,000 barrels per day due to the perceived effects of the unusually cold winter on driving as well as optimistic assumptions about retirements of older, less fuel-efficient vehicles. But DRI forecasted larger increases in jet fuel and residual fuel oil demand than did the EIA. Contributing to the AGA's flat demand growth was an 18-percent decline in residual oil demand and weak motor gasoline demand growth. In addition, the timing of the AGA forecast—which evidently precluded the availability of actual winter-related demand data—appears to account for some of the "missing" demand growth vis-a-vis other projections.

Growth is projected in 1995 for petroleum demand in all of the forecasts, but with a wide variation. AGA projected an increase of only 50,000 barrels per day due to continued weakness in gasoline markets and declines in both residual and distillate fuel oil demand brought about by higher oil prices. NERA, on the other hand, projected growth of 360,000 barrels per day based on higher-than-consensus projections of economic growth. EIA projected petroleum demand to increase by 170,000 barrels per day, or 1.0 percent, reflecting a slowdown in overall economic growth.

Natural gas consumption in 1994 is projected to rise in all the forecasts. The increases in consumption range from 0.30 trillion cubic feet (DRI), or 1.5 percent, to 0.79 trillion cubic feet (EIA), or 3.9 percent. In 1995, increases range from 0.08 trillion cubic feet (NERA) to 0.80 trillion cubic feet (AGA). EIA projected growth of 0.47 trillion cubic feet, or 2.2 percent. Divergent assumptions about economic growth as well as about relative prices of competing fuels in each of the forecast years account for the bulk of the differences in natural gas consumption projections. In the AGA projection for 1995, for example, high growth in natural gas demand is correlated with robust economic growth. The low demand growth in the DRI and NERA projections stems largely from increases in the relative price for natural gas and a sharp moderation in economic growth.

In contrast, 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 (0.3-percent) increase in DRI's 1994 coal demand stems from moderate (1.9-percent) demand growth and substantial growth in nuclear and hydroelectric generation capacity. At the other end of the spectrum, AGA projects a 3.5-percent increase in coal demand as a result of minimal increase in power generation from fossil fuels and nuclear power plants. EIA projects a 2.5-percent jump in coal demand, driven largely by a 3.3-percent hike in electricity demand. In 1995, coal demand growth rates range from 1.1 percent (DRI) to 3.6 percent (AGA). EIA projects a 1.3-percent growth rate for that year.

Notes: Chapter 3

[36]U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202 (94/2Q).

[37]DRI / McGraw-Hill, *Energy Review* (Spring-Summer May 1994); National Economic Research Associates, *Energy Outlook* (April 1994); American Gas Association—TERA Base Case 1994 (January 1994); Independent Petroleum Association of America, *IPAA Supply and Demand Committee Long-Term Forecast, 1993-2010* (March 1994).

4. Forecast Evaluation

This chapter presents an evaluation of errors between published forecast values and subsequent historical values for selected major energy variables: energy prices, macroeconomic variables, weather, demand, and production for petroleum, natural gas, coal, and electricity as published in the third quarter 1992 through the fourth quarter 1993 issues of the *Short-Term Energy Outlook (Outlook)*.[38] Detailed forecast error tables for selected variables are presented in Appendix A. 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 1993 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 8 years of *Outlooks* (32 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 16 presents a summary of the average absolute errors for the forecasts published in the third quarter 1992 through the fourth quarter 1993 issues of the *Outlook*, as well as the average absolute errors published in the previous issue of the *Supplement* (covering the third quarter 1991 through the fourth quarter 1992 issues of the *Outlook*). Table 16 shows that, in percentage terms, 15 out of 34 (44 percent) of the forecasts either improved or were equal to or close to the forecast errors examined in the 1993 *Supplement*. Four of the seven selected price variables showed increased forecasting errors. The continued decline of crude oil prices led to overstatements for the refiners acquisition cost (RAC) of crude oil (Table A1) which, in turn, resulted in overstatements for most of the petroleum product prices. There were improvements for distillate fuel demand, "other" petroleum products demand, lower 48 crude oil production, net oil imports, and petroleum stocks.

There were also improvements in forecast in all sectors of electricity sales, with the exception of industrial sales. In addition, there were forecast improvements for electricity generation by petroleum, nuclear, and hydroelectric power. Natural gas demand had larger errors than reported in the previous *Supplement* because of the flattening of seasonal price patterns that occurred in the first half of 1993. 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, natural gas wellhead prices, petroleum and natural gas generation had the largest errors.

The summary forecast evaluation table presents the average absolute percent error of 21 quarterly forecasts made in six *Outlooks*, from the third quarter 1992 through the fourth quarter 1993. The 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 A1 through A36, 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 16. Summary of Absolute Errors, *1993 Annual Supplement* Compared to *1994 Annual Supplement*

	Average Absolute Percent Error

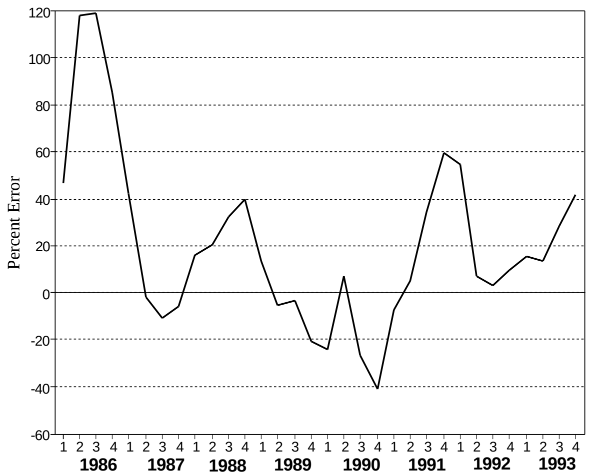
in forecasting the RAC, while obviously having an adverse effect on the results for petroleum product prices, also affect to a lesser degree, the results of natural gas prices, as well as petroleum and natural gas demand and production. Based on the mid-oil price case forecasts, the overall average absolute error for the imported RAC was 20.3 percent or $3.11 per barrel, over the last six issues of the *Outlook.* This compares with a previously reported error of 8.2 percent in the 1993 *Supplement* (Tables 16 and A1). All of the reports evaluated overstated the forecasts, not anticipating the falling price of the imported RAC. The principal reasons for the decline in the RAC were unexpected relatively high levels of net exports from an economically chaotic Russia (although production declined, so too did internal demand), higher than expected production from 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 an enigmatic task. This is because swift and sizeable 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. Moreover, it is difficult to precisely pin down turning points for economic trends such as the recovery (or lack of) for industrial production in Western Europe and Japan. As a result, the RAC forecast errors for a particular quarter have often been quite large. Examining forecasts for one year ahead (four quarters ahead) for the periods for 1986 through 1993, 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 2). 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 17 of these 32 quarters evaluated here, the actual prices have fallen outside the range of expectations.[39]

Petroleum Product Prices

Retail motor gasoline price forecasts had an average absolute error of 5.8 percent or about 7 cents per gallon (Table A2). Every one of the motor gasoline price forecast errors was higher than expected. Almost all of the errors can be attributed to the overstatements of RAC prices, a major component of gasoline prices.

Figure 2. Imported Crude Oil Prices
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 45.

The residential heating oil price forecasts had an average absolute error of 8.7 percent over the last six *Outlooks* compared to 7.1 percent in the previous *Supplement* (Tables 16 and A3). Like motor gasoline, all of the forecast errors were higher than expected due to low crude oil prices. The largest errors occurred in the fourth quarter of 1993, due to unusually warm weather and low world oil prices.

Residual fuel oil price forecasts had an average absolute error of 14.0 percent, over the last six *Outlooks* (Table A4). This was an improvement for this volatile fuel price over the 16.2 percent error reported in the previous *Supplement*. Crude oil price overstatements, and a mild winter in the fourth quarter of 1993 accounted for most of the errors. The price was underestimated for only one quarter of the evaluation period. This was the second quarter of 1993 where error was due to the unusually cold weather in middle and late March, leading to a jump in natural gas prices (see below) which, in turn, put upward pressure on residual fuel oil prices.

Natural Gas

Forecast errors for natural gas wellhead prices have averaged 11.0 percent over the last year and a half (Table A5). The errors were somewhat weather related with unusually cold weather on the East Coast in the late winter (March) and early spring of 1993, which left inventories low; and to warmer-than-normal weather in the gas-consuming regions in the fourth quarter of that year. In addition, the pronounced seasonal price patterns that have occurred in the past have flattened over the last few years due to more efficient inventory management and to the growth of the futures market. The forecasts have not sufficiently reflected these trends. The third quarter 1993 price was consistently underestimated as warmer-than-normal weather in some parts of the country resulted in high demand at gas-burning electric utilities, putting upward pressure on prices.

Residential natural gas price forecast errors were relatively small, averaging 2.7 percent (Table A6). 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 some instances, the forecasts overestimated the price, with most of the errors due to overstatements of wellhead prices.

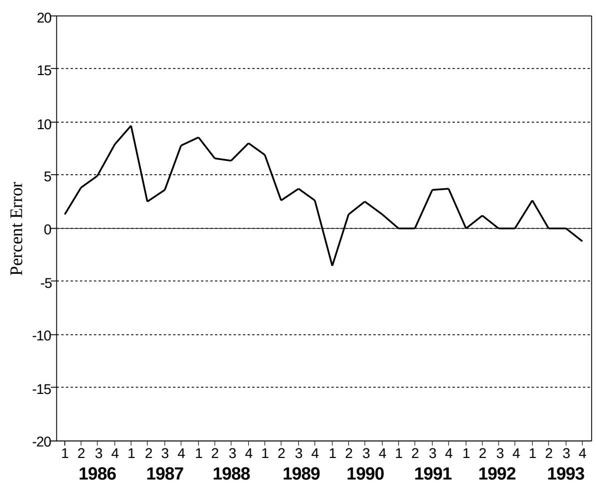
Residential Electricity

Residential electricity price forecasts, with a 1.0-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 A7). Eight of the 21 forecast quarters reported in Table A7 had forecasts exactly equal to the actual data. 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 3 illustrates that one-year-ahead projections for this price have improved considerably over the last 8 years. The one-year-ahead projection for the first quarter of 1987 was overstated by nearly 10 percent (Figure 3). 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 1.3 percent for the one-year-ahead projections made for 1990 through 1993.

Electric Utility Coal Prices

Projections for coal prices to electric utilities have averaged a 3.3-percent error rate, which was the same error rate as in the previous *Supplement* (Tables 16 and A8). 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 up and down. The forecasts have consistently overstated prices, but by a relatively small amount.

Figure 3. U.S. Residential Electricity Prices
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 45.

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 1.4 percent over the six most recent forecast quarters (Table A9). All of the errors were underestimations as the overall economy grew more rapidly than had been forecasted.

The Industrial Production Index for Manufacturing

The historical (actual) numbers from 1991 and 1992 for the industrial production index for manufacturing were revised in 1993. 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 (1951-1980) 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. 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). The third quarter 1993, for example, was 9.1 percent warmer than normal (Table A12). Therefore, projections for electricity sales, particularly the residential and commercial sectors were somewhat understated.

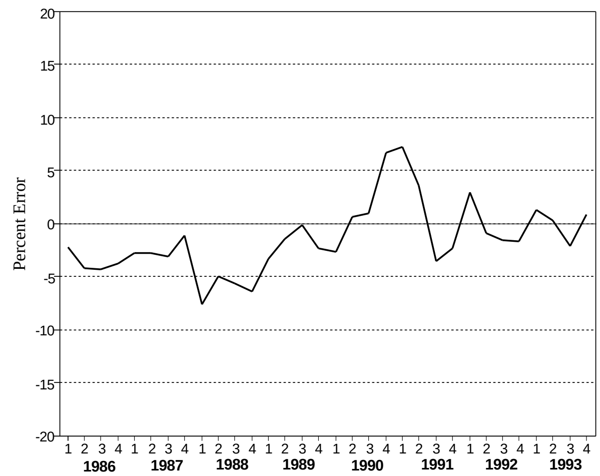
Petroleum

Demand

For the six *Short-Term Energy Outlooks* evaluated, the average absolute forecasting error for petroleum demand was 1.4 percent or 230,000 barrels per day (Table A13), equal to the same error rate in the previous *Supplement*. For the major petroleum products, the average absolute error ranged from 1.1 percent for motor gasoline, to 7.3 percent for residual fuel oil. The one-year-ahead forecasts for total petroleum demand never erred by more than 8 percent for 1986 through 1993, but the forecasts made prior to 1989 were consistently understated (Figure 4). 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 1.1 percent (or 90,000 barrels per day) compared to 1.0 percent in the previous *Supplement* (Tables 16 and A14). Nearly all of the forecast errors, albeit small, tended to understate gasoline demand. Motor gasoline demand grew between 1992 and 1993, while the forecasts tended to project very small growth over that period. This was due to the assumption that efficiency gains (average miles per gallon) would offset increases in fleet size and vehicle-miles traveled. In fact, efficiency gains were somewhat overstated.

Figure 4. U.S. Total Petroleum Demand
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 45.

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*. These "normals" are used in projecting heating fuels demand. Consequently, the average absolute percent error for distillate fuel was a relatively small 2.8 percent, an improvement over the 4.3 percent error reported in the previous *Supplement* (Table A15). Residual fuel oil forecast errors averaged 7.3 percent (Table A16). Demand for this fuel was overstated by an average of 18 percent for the first quarter 1993. This was the result of switching to natural gas, as gas prices were unseasonably low due to high storage levels, the result of warm weather.

Jet fuel demand forecasts had an average error of 3.8 percent, or 60,000 barrels per day, compared to an average error of 3.1 percent in the previous report (Table A17). For 1993, most of the forecasts tended to overstate demand, not anticipating the continued economic troubles in the airline industry.

Forecasts of demand for "other" petroleum products include motor gasoline blending components, asphalt, road oil, petroleum coke, LPG, waxes, lubricants, unfinished oils, aviation gasoline blending components, and miscellaneous oils, and show an improvement. The average absolute forecasting error for "other" petroleum products was 3.1 percent, or 130,000 barrels per day (Table A18), compared to 4.8 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 1.3 percent or 90,000 barrels per day (Table A19). 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. Although slightly more than half of the forecast errors of each of the production categories were in the same direction, there were 10 of 21 forecast quarters where the errors had opposite signs. This yielded offsetting errors for total domestic production, which as an aggregate, had an average absolute percent error smaller than either of its two components (Tables A19, A20, and A21).

Total Petroleum Net Imports, Excluding SPR

Forecast accuracy for net oil imports gained considerably compared to the last *Supplement*, with an average absolute error of 2.4 percent versus 5.2 percent (Table A22). Errors in the projections of net petroleum imports reflect combined errors in predicting crude oil production, petroleum product demand, and crude and product stock changes. Improved accuracy in forecasting petroleum stock changes (see below) is the principal reason for the smaller forecast errors for net oil imports.

Stocks

The forecasts for petroleum inventories in the *Outlook* had an average absolute forecast error of 1.5 percent, compared to 2.6 percent in the previous *Supplement*. Four of the six evaluated quarters had average absolute error of less than 1 percent. The second quarter of 1993 was understated by an average of 3.5 percent since total demand was consistently overstated for that quarter.

Natural Gas

Natural Gas Demand

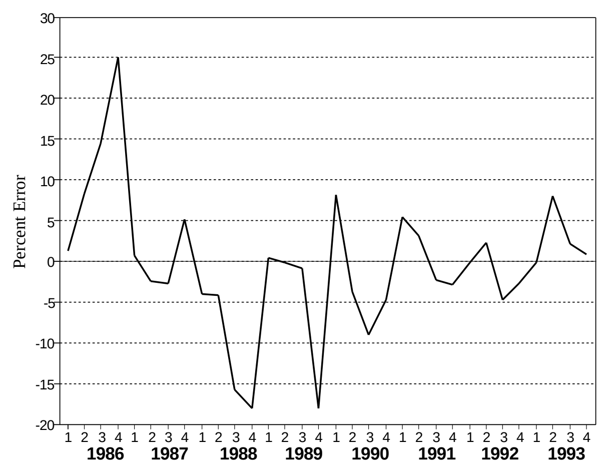
The average absolute error for the total natural gas demand forecasts was 3.7 percent (Table A24) compared to the 2.7 percent error reported in the previous *Supplement*. The volatile natural gas prices (Table A5) had little effect on the demand forecasts, except in the second quarter of 1993, where unseasonably high actual prices (the result of a cold spring and low inventories) contributed to an overstatement of demand by nearly 11 percent.

The one-year-ahead forecasts for natural gas demand had errors higher than 20 percent for forecasts made for 1986 through 1989 (Figure 5). 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 relatively small and consistent over the last several years. The average forecast error was 2.2 percent versus 2.1 percent in the previous *Supplement* (Table A25). However, forecasts made for the third quarter 1992, fourth quarter 1992, and first quarter 1993, tended to overestimate production by an average of over 4 percent. Underground storage withdrawals for the fourth quarter of 1992 were higher than forecasted, thus reducing the amount of natural gas production that was needed to meet expected demand.[40] In addition, the weather was warmer than normal for the first quarter 1993, reducing demand, thus lessening the need for additional production.

Figure 5. U.S. Natural Gas Demand
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 45.

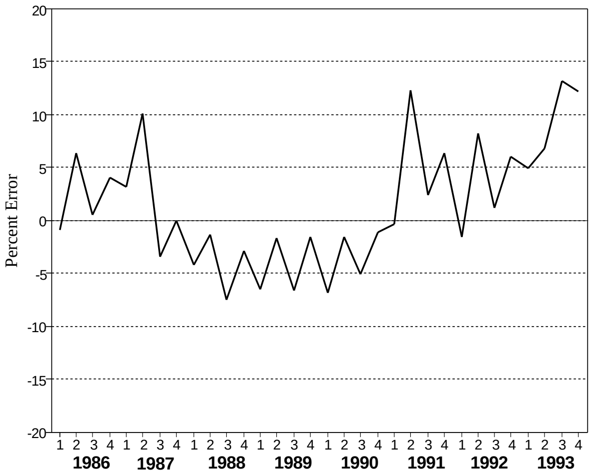
Coal

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 is consumed 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.[41]

The average absolute error for total domestic coal demand increased to 2.3 percent, or 6 million tons, from the 1.9 percent reported in the previous *Supplement*. All five forecasts for the third quarter of 1993 understated coal demand, by an average of 5.0 percent. This was due to the hotter-than-normal summer which increased electricity generation for that period.

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 than never occurred (Figure 6). 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

Figure 6. U.S. Coal Production
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 45.

production, especially in 1993 when a selective coal strike reduced production.

The average absolute error for total coal production was 7.8 percent (Table A27). This compares to the 2.7 percent error in the previous *Supplement*. Production was severely curtailed during the last 9 months of 1993, primarily because of the United Mine Workers of America (UMWA) strike that occurred during this period. Because the strike was unanticipated, production was considerably overestimated for this period.

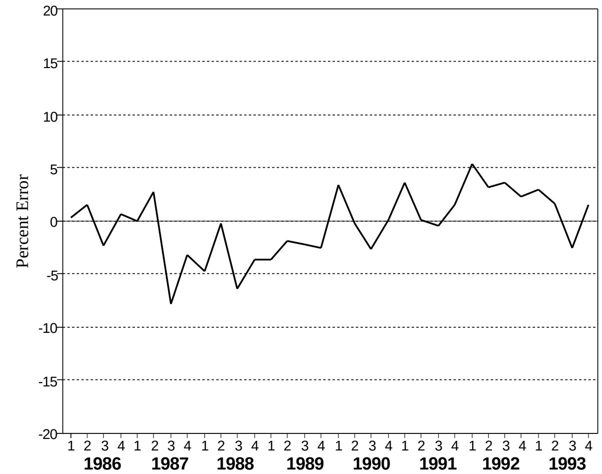
Electric Utilities

The average forecast error for total electricity sales was 1.9 percent compared to 2.2 in the previous report (Table A28). With the exception of the third quarter of 1993, almost all of the forecasts overstated sales, but by a very small amount.

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 principal reason for the underestimations in the third quarter of 1993 was hotter-than-normal 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. 33). The accuracy of the one-year-ahead forecasts have improved slightly over the last 8 years. The average absolute error for the 16 forecasts made for 1986 through 1989 was 2.8 percent.[42] For the 16 forecasts made for 1990 through 1993, the absolute average error was 2.2 percent.[43] 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 1990-1993 were overstated in 12 of 16 quarters (Figure 7).

Residential electricity sales (Table A29) has an average absolute forecast error of 4.1 percent, with an underestimation of 8.6 percent in the third quarter of 1993, due to the hot weather. Commercial electricity sales, which are also weather-related, but to a lesser degree, were understated by an average of 2.9 percent during the same period (Table A30). The average absolute error for commercial sales was 1.9 percent. Industrial electricity sales, which are even less sensitive to weather, had an average forecast error of just 1.7 percent and an average error of 1.5 percent in the third quarter of 1993. (Table A31).

Figure 7. U.S. Electricity Demand
(One-Year-Ahead Forecast Percent Error)



Sources: Details provided in Figure Reference section, p. 45.

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 2.9 percent (Table A32). A large portion of this error occurred in the third quarter of 1993 (understated by 6.2 percent) when the unusually hot weather resulted in greater than normal sales which led to an underestimation of total generation.

Electricity generation from petroleum (primarily residual fuel oil) had an average error of 20.3 percent (Table A33) compared to 27.5 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.

Electricity generation from natural gas had an average absolute error rate of 11.5 percent (Table A34). Forecasts for the second quarter of 1993 were the least accurate with a relatively high error rate of 35.3 percent. This was the result of the overestimation of total electricity sales and the underestimation of natural gas prices, which had increased rapidly in that quarter (Tables A30, A4, and A7).

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 4.2 percent (Tables A35 and A32).

Hydroelectric power had an average absolute forecast error of 10.9 percent, an improvement from the 19.7 percent error in the previous *Supplement* (Table A36). The large forecast error in the previous Supplement resulted from the below-normal precipitation that occurred in 1992. These forecast assume normal water conditions. In 1993, the water conditions were closer to normal and thus the forecasts were more accurate.

Notes: Chapter 4

[38]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.

[39]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 92/4Q, low and high imported crude oil price cases.

[40]Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202 (92/3Q) and (92/4Q).

[41]*Monthly Energy Review*, DOE/EIA-0035(94)/04, Table 6.2. For the years 1990-1992, coal consumption at electric utilities averaged 87 percent of total consumption.

[42]Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226, various issues, Table 3, and Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 85/1Q through 88/4Q.

[43]Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226, various issues, Table 3 and, Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202, issues 89/1Q through 92/4Q.

5. Forecasting Demand for "Other" Petroleum Products

Most discussion on petroleum product demand focuses on the five major products used in the transportation, residential, commercial and utility sectors: motor gasoline, jet fuel, distillate fuel, residual fuel, and liquefied petroleum gases. However, the third largest category of product demand is "other" petroleum products, which is made up of 14 miscellaneous products and represents about 14 percent of total petroleum product demand (Table 17). The econometric models of "other" petroleum product demands in the Short-Term Integrated Forecasting System (*STIFS*) have been updated since the last *STIFS* documentation report.[44] That report includes documentation for the major petroleum products. Documentation for the revised "other" petroleum product demand models is provided below. Detailed regression results are found in Appendix B.

The category "other" petroleum products represents the aggregation of 14 individual petroleum products (Table 18). Linear regression equations were developed and tested for 7 of these products or groups of products:

- Pentanes Plus
- Unfinished Oils
- Petrochemical Feedstocks
- Petroleum Coke
- Asphalt and Road Oil
- Still Gas
- Remaining Miscellaneous Petroleum Products.

Crude Oil: A small volume of crude oil used directly as fuel (COTCPUS) is reported as "product supplied" in the *Petroleum Supply Monthly*. This volume has declined steadily since 1983 and averaged 11 thousand barrels per day in 1993.[45] Demand in 1993 was reported only in Petroleum for Administration Defense (PADD) District V, the West Coast. Crude oil product supplied is assumed to remain fixed at 10 thousand barrels per day through the forecast period.

$$\text{COTCPUS} = 0.010$$

Pentanes Plus: Pentanes-plus represents a mixture of hydrocarbons, mostly pentanes and heavier (isopentane, natural gasoline, and plant condensate). Pentanes plus demand (PPTCPUS) is estimated as a function of the refinery yield of motor gasoline, a time trend, and monthly dummies using ordinary least squares regression with a first-order autocorrelation correction factor:[46]

Table 17. Petroleum Products Demand—1993 Averages
(Thousand Barrels per Day)

Product	1993 Average Demand	Percent of Total Demand
Finished Motor Gasoline	7,483	43.5 %
Jet Fuel	1,467	8.5 %
Distillate Fuel Oil	3,031	17.6 %
Residual Fuel Oil	1,068	6.2 %
Liquefied Petroleum Gases	1,714	10.0 %
"Other" Petroleum Products	2,430	14.1 %
Totals	**17,193**	**100.0 %**

Source: Energy Information Administration, *Petroleum Supply Monthly, February 1994*, DOE/EIA-0109(94/02) (Washington, DC, March 1, 1994), p. 39.

Table 18. "Other" Petroleum Product Demands—1992 Averages
(Thousand Barrels per Day)

Product	***STIFS* Variable Name**	Series Start Date	1993 Average
Crude Oil	COTCPUS	8101	11
Pentanes Plus	PPTCPUS	[a]8401	196
Unfinished Oils	UOTCPUS	7601	-184
Aviation Gasoline Blend Components	ABTCPUS	8101	(s)
Finished Aviation Gasoline	AVTCPUS	7501	21
Kerosene	KSTCPUS	7501	49
Petrochemical Feedstocks[b]	FETCPUS	7501	571
Special Naphthas	SNTCPUS	[c]	54
Lubricating Oils	LUTCPUS	7501	152
Waxes	WXTCPUS	[c]	20
Petroleum Coke	PCTCPUS	7801	364
Asphalt and Road Oil	ARTCPUS	7501	476
Still Gas	SGTCPUS	7501	654
Miscellaneous Products	MSTCPUS	[c]	44
Total			**2,430**

[a]Data in *STIFS* database covering period 8101 to 8312 is not on consistent basis with data from 8401 on.
[b]Includes naphtha and other oils for petrochemical feed use.
[c]Not available in *STIFS* database.
(s) = Less than 500 barrels per day.

PPTCPUS = f(TIME, MGYLD, Monthly dummies, AR1)

TIME = Time trend dummy variable
MGYLD = Refinery yield of motor gasoline

Monthly Dummies = 11 monthly dummy variables
AR1 = 1st-Order autocorrelation correction factor

Unfinished Oils: Includes all oils requiring further processing, except those requiring only mechanical blending (naphtha and lighter oils, kerosene and light gas oils, heavy gas oils, and residuum). Demand for unfinished oils (UOTCPUS) is estimated as a function of refinery inputs of unfinished oils and monthly dummy variables:[47]

UOTCPUS = f(UORIPUS, Monthly Dummies)

UORIPUS = Refinery inputs of unfinished oils

Aviation Gasoline Blend Components: Demand for aviation gasoline blend component has consistently been reported as less than 500 barrels per day. Forecast demand for aviation gasoline blend components (ABTCPUS) is set equal to zero.

ABTCPUS = 0.0

Petrochemical Feedstocks: Petrochemical feedstocks are derived from petroleum for the manufacture of chemicals, synthetic rubber, and a variety of plastics. A motor gasoline / propane price ratio is included in the regression equation for petrochemical feedstocks (FETCPUS) to capture substitution between petrochemical feedstocks and lighter products such as liquefied petroleum gases as raw materials in petrochemical processes:

FETCPUS = f(ZO28IUS, MGWHUUSX / PRTCUUS, Monthly Dummies, AR1)

ZO28IUS = Industrial production index, chemicals and products
MGWHUUSX = Wholesale motor gasoline price
PRTCUUS = Retail propane price

Petroleum Coke: A by-product of the upgrading of the heaviest petroleum fractions (e.g., residual fuel oil) to more valuable lighter products in Coking units. Petroleum coke is produced as either sponge coke, needle coke, or fluid coke which vary primarily by particle size. About 65 percent of the coke produced in the U.S. is used as fuel. The remaining 35 percent is sponge coke that, when calcined, is sold as premium-grade coke used in the manufacture of aluminum anodes, furnace electrodes and liners, and shaped graphite products.[48] The largest use of calcined petroleum coke is in the form of anodes for the electrolytic reduction of aluminum ore to make high-purity metal. Exports make up about 40 percent of total petroleum coke sales.

Domestic petroleum coke demand (PCTCPUS) is estimated as a function of a time trend, and monthly dummy variables.[49]

PCTCPUS = f(TIME, Monthly Dummies)

Asphalt and Road Oil: The heaviest fraction of many crude oils includes natural bitumens or asphaltenes and are generally called asphalt. Demand for asphalt and road oil (ARTCPUS) is positively responsive to the level of industrial production and negatively related to cold weather.[50]

ARTCPUS = f(ZOTOIUS, ZWHDDUS / ZSAJQUS, TIME, Monthly Dummies)

ZOTOIUS = Industrial production index - total, seasonally adjusted
ZWHDDUS / ZSAJQUS = Heating degree-days per day deviation from normal

Still Gas: Still gas (also known as refinery gas) is any form or mixture of gas produced in refineries by cracking, reforming, and other processes. Still gas is produced as a by-product in the upgrading of heavy petroleum fractions to more valuable lighter products and is consumed internally as refinery fuel. Since the supply of still gas creates its own demand, still gas demand (SGTCPUS) is modelled as a function of refinery inputs of crude oil and the refinery yield or motor gasoline. For a given level of refinery crude oil inputs, still gas production should be positively related to the production of motor gasoline.

SGTCPUS = f(CORIPUS, MGYLD, D86ON, Monthly Dummies, AR1)

CORIPUS = Refinery inputs of crude oil, million barrels per day

D86ON = Dummy variable equal to 1 for DATE greater than 8512, 0 otherwise

Remaining Miscellaneous Products: The remaining miscellaneous products, about 18 percent of the total, is estimated under a new subaggregate variable, MZTCPUS. The total volume of remaining miscellaneous products has declined steadily since 1985. While demand for lubricating oils, which makes up about 44 percent of this category, has been flat since 1984, demands for special naphthas and kerosene have shown significant declines (Table 19).

Table 19. Remaining Miscellaneous Products
(Thousand Barrels per Day)

Year	Lube Oil (LUTCPUS)	Special Naphthas (SNTCPUS)	Kerosene (KSTCPUS)	"Other" Products	Total Miscellaneous Products (MZTCPUS)
1993	152	54	49	86	341
1992	149	54	41	87	331
1991	146	46	46	112	350
1990	164	56	43	105	368
1989	159	56	84	115	414
1988	155	59	96	123	433
1987	161	76	95	106	438
1986	142	68	98	112	420
1985	145	83	114	110	452
1984	156	108	115	106	485

Note: "Other" products includes finished aviation gasoline (AVTCPUS), waxes (WXTCPUS), and miscellaneous products (MSTCPUS).

Special naphthas represent all finished products within the naphtha boiling range that are used as paint thinners, cleaners, or solvents. The steady decline in demand for special naphthas may reflect increasingly stringent environmental regulations or a greater participation in the market from the petrochemical sector.

Kerosene is used primarily in space heaters, cooking stoves, and water heaters. The steady decline in kerosene demand likely reflects fuel switching (e.g., to natural gas or bottled propane) and greater demand for kerosene-type jet fuel.

Remaining miscellaneous products are regressed against time and monthly dummies.[51]

MZTCPUS = f(ZOMNIUS, ZWHDDUS / ZSAJQUS, TIME, Monthly Dummies)

ZOMNIUS = Industrial production index - manufacturing, seasonally adjusted

Other Identities: Several time series are created as aggregations of different miscellaneous petroleum products through identities:

CPTCPUS = PPTCPUS + COTCPUS

MITCPUS = SGTCPUS + ARTCPUS + PCTCPUS + MZTCPUS

PSTCPUS = CPTCPUS + MITCPUS + FETCPUS

Notes: Chapter 5

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

[45]Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(94/02), (Washington, DC, March 1994), p. 39.

[46]Other variables (heating degree-days and the industrial production index) were tested as proxies for demand shocks but were not found to be statistically significant.

[47]Other variables were tested, such as heating degree days, industrial production index, and a motor gasoline-to-distillate price ratio, but were not statistically significant.

[48]Edward J. Swain, "Major Growth in Coke Production Takes Place," *Oil and Gas Journal* (May 6, 1991), pp. 100-102.

[49]The equation was also tested with the industrial production index for the nonferrous metals manufacturing sector which includes aluminum production. However, the estimated coefficient was not statistically significant.

[50]State and local government purchases of structures (which includes road construction) was tested as an alternative to the industrial production index as a proxy for demand. However, the estimated coefficient was not statistically significant.

[51]The equation was also tested with the total demand for motor gasoline plus distillate fuel oil as an independent variable to reflect demand for lube oils. However, the estimated coefficient was not statistically significant.

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 2 through 7, 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. Projections for oxygenated demand are based on Energy Information Administration data and internal analysis.

2. **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 92/4Q 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 1993.

3. **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 92/4Q base (mid-price) case, Table 5, "Energy Prices."

4. **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 92/4Q base (mid-price) case. Table: "U.S. Petroleum Supply and Demand: Mid-World Oil Price Case."

5. **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 92/4Q base (mid price) case. Table: "U.S. Natural Gas Supply and Demand: Mid-World Oil Price Case."

6. **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 92/4Q base (mid-price) case. Table: "U.S. Coal Supply and Demand: Mid-World Oil Price Case."

7. **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 92/4Q base (mid-price) case. Table: "U.S. Electricity Supply and Demand: Mid-World Oil Price Case."

Appendix A

Detailed Forecast Error Tables

Table A1. Refiner Acquisition Cost of Imported Crude Oil, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1992 3rd	1992 4th	1993 1st	1993 2nd	1993 3rd	1993 4th	Average Absolute Error
	(dollars per barrel)						
92/3Q	20.00	20.00	20.00	20.00	20.00	20.00	2.94
92/4Q	--	20.00	20.00	20.00	20.00	20.00	3.41
93/1Q	--	--	19.00	19.00	19.00	19.00	2.83
93/2Q	--	--	--	18.00	19.00	19.00	2.88
93/3Q	--	--	--	--	18.00	19.00	3.66
93/4Q	--	--	--	--	--	17.50	3.41
Actual	**19.42**	**18.27**	**17.34**	**17.66**	**15.60**	**14.09**	
Average Absolute Error	0.58	1.73	2.33	1.59	3.60	4.99	3.11
	(percent error)						
92/3Q	3.0	9.5	15.3	13.3	28.2	41.9	17.2
92/4Q	--	9.5	15.3	13.3	28.2	41.9	20.5
93/1Q	--	--	9.6	7.6	21.8	34.8	17.5
93/2Q	--	--	--	1.9	21.8	34.8	18.3
93/3Q	--	--	--	--	15.4	34.8	24.6
93/4Q	--	--	--	--	--	24.2	24.2
Average Absolute Percent Error	3.0	9.5	13.4	9.0	23.1	35.4	20.3

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A2. Retail Motor Gasoline Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter 1992 3rd	1992 4th	1993 1st	1993 2nd	1993 3rd	1993 4th	Average Absolute Error
	(dollars per gallon)						
92/3Q	1.27	1.28	1.23	1.27	1.31	1.32	0.09
92/4Q	--	1.26	1.20	1.23	1.28	1.31	0.08
93/1Q	--	--	1.16	1.19	1.24	1.27	0.05
93/2Q	--	--	--	1.23	1.24	1.22	0.06
93/3Q	--	--	--	--	1.21	1.22	0.05
93/4Q	--	--	--	--	--	1.21	0.04
Actual	**1.23**	**1.21**	**1.17**	**1.19**	**1.16**	**1.17**	
Average Absolute Error	0.04	0.06	0.03	0.04	0.10	0.09	0.07
	(percent error)						
92/3Q	3.3	5.8	5.1	6.7	12.9	12.8	7.7
92/4Q	--	4.1	2.6	3.4	10.3	12.0	6.4
93/1Q	--	--	-0.9	0.0	6.9	8.5	4.1
93/2Q	--	--	--	3.4	6.9	4.3	4.8
93/3Q	--	--	--	--	4.3	4.3	4.3
93/4Q	--	--	--	--	--	3.4	3.4
Average Absolute Percent Error	3.3	5.0	2.8	3.4	8.3	7.5	5.8

-- = 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(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A3. Residential Heating Oil Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(dollars per gallon)			
92/3Q	0.96	1.03	1.03	0.98	0.96	1.04	0.10
92/4Q	--	1.02	1.04	0.94	0.94	1.06	0.09
93/1Q	--	--	0.99	0.91	0.90	1.01	0.06
93/2Q	--	--	--	0.92	0.91	0.98	0.06
93/3Q	--	--	--	--	0.89	0.97	0.07
93/4Q	--	--	--	--	--	0.95	0.07
Actual	**0.90**	**0.94**	**0.95**	**0.91**	**0.85**	**0.88**	
Average Absolute Error	0.06	0.09	0.07	0.03	0.07	0.12	0.08
				(percent error)			
92/3Q	6.7	9.6	8.4	7.7	12.9	18.2	10.5
92/4Q	--	8.5	9.5	3.3	10.6	20.5	10.4
93/1Q	--	--	4.2	0.0	5.9	14.8	6.1
93/2Q	--	--	--	1.1	7.1	11.4	6.4
93/3Q	--	--	--	--	4.7	10.2	7.5
93/4Q	--	--	--	--	--	8.0	8.0
Average Absolute Percent Error	6.7	9.0	7.4	3.0	8.2	13.8	8.7

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A4. Residual Fuel Oil Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(dollars per barrel)			
92/3Q	14.68	16.95	16.80	15.14	15.75	17.92	1.94
92/4Q	--	16.85	16.54	15.38	15.21	16.62	1.70
93/1Q	--	--	16.49	15.19	14.87	16.38	1.72
93/2Q	--	--	--	13.46	14.11	15.42	1.65
93/3Q	--	--	--	--	14.53	16.10	2.21
93/4Q	--	--	--	--	--	15.73	3.03
Actual	**15.82**	**16.04**	**14.73**	**15.10**	**13.52**	**12.70**	
Average Absolute Error	1.14	0.86	1.88	0.51	1.37	3.66	1.88
				(percent error)			
92/3Q	-7.2	5.7	14.1	0.3	16.5	41.1	13.2
92/4Q	--	5.0	12.3	1.9	12.5	30.9	11.8
93/1Q	--	--	11.9	0.6	10.0	29.0	12.3
93/2Q	--	--	--	-10.9	4.4	21.4	12.0
93/3Q	--	--	--	--	7.5	26.8	16.8
93/4Q	--	--	--	--	--	23.9	23.9
Average Absolute Percent Error	7.2	5.4	12.8	3.4	10.2	28.8	14.0

-- = 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(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A5. Natural Gas Wellhead Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(dollars per thousand cubic feet)						
92/3Q	1.54	1.79	1.82	1.52	1.54	1.81	0.32
92/4Q	--	2.20	2.10	1.82	1.81	2.16	0.17
93/1Q	--	--	2.02	1.75	1.86	2.16	0.19
93/2Q	--	--	--	1.88	1.89	2.24	0.18
93/3Q	--	--	--	--	1.98	2.29	0.15
93/4Q	--	--	--	--	--	2.35	0.32
Actual	**1.77**	**2.19**	**1.86**	**2.08**	**2.01**	**2.03**	
Average Absolute Error	0.23	0.21	0.15	0.34	0.19	0.21	0.22
	(percent error)						
92/3Q	-13.0	-18.3	-2.2	-26.9	-23.4	-10.8	16.1
92/4Q	--	0.5	12.9	-12.5	-10.0	6.4	8.3
93/1Q	--	--	8.6	-15.9	-7.5	6.4	9.6
93/2Q	--	--	--	-9.6	-6.0	10.3	8.7
93/3Q	--	--	--	--	-1.5	12.8	7.2
93/4Q	--	--	--	--	--	15.8	15.8
Average Absolute Percent Error	13.0	9.4	7.9	16.2	9.7	10.4	11.0

-- = Not applicable.
E = Estimated.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A6. Residential Natural Gas Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(dollars per thousand cubic feet)						
92/3Q	7.25	5.90	5.74	6.28	7.36	6.00	0.16
92/4Q	--	5.98	5.81	6.33	7.46	6.07	0.15
93/1Q	--	--	5.79	6.26	7.38	5.99	0.24
93/2Q	--	--	--	6.33	7.44	6.03	0.23
93/3Q	--	--	--	--	7.51	6.02	0.25
93/4Q	--	--	--	--	--	6.04	0.11
Actual	**7.29**	**5.96**	**5.69**	**6.45**	**7.88**	**6.15**	
Average Absolute Error	0.04	0.04	0.09	0.15	0.45	0.13	0.19
	(percent error)						
92/3Q	-0.5	-1.0	0.9	-2.6	-6.6	-2.4	2.5
92/4Q	--	0.3	2.1	-1.9	-5.3	-1.3	2.4
93/1Q	--	--	1.8	-2.9	-6.3	-2.6	3.6
93/2Q	--	--	--	-1.9	-5.6	-2.0	3.3
93/3Q	--	--	--	--	-4.7	-2.1	3.6
93/4Q	--	--	--	--	--	-1.8	1.8
Average Absolute Percent Error	0.5	0.7	1.6	2.3	5.7	2.0	2.7

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A7. Residential Electricity Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(cents per kilowatthour)						
92/3Q	8.50	8.00	8.00	8.50	8.70	8.30	0.08
92/4Q	--	8.00	7.90	8.40	8.70	8.20	0.10
93/1Q	--	--	7.90	8.40	8.60	8.10	0.13
93/2Q	--	--	--	8.40	8.70	8.20	0.07
93/3Q	--	--	--	--	8.70	8.30	0.00
93/4Q	--	--	--	--	--	8.30	0.00
Actual	**8.60**	**8.20**	**7.80**	**8.50**	**8.70**	**8.30**	
Average Absolute Error	0.10	0.20	0.13	0.07	0.02	0.07	0.08
	(percent error)						
92/3Q	-1.2	-2.4	2.6	0.0	0.0	0.0	1.0
92/4Q	--	-2.4	1.3	-1.2	0.0	-1.2	1.2
93/1Q	--	--	1.3	-1.2	-1.1	-2.4	1.5
93/2Q	--	--	--	-1.2	0.0	-1.2	0.8
93/3Q	--	--	--	--	0.0	0.0	0.0
93/4Q	--	--	--	--	--	0.0	0.0
Average Absolute Percent Error	-1.2	2.4	1.7	0.9	0.2	0.8	1.0

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A8. Coal to Electric Utility Prices, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(dollars per million Btu)						
92/3Q	1.45	1.47	1.44	1.48	1.46	1.45	0.07
92/4Q	--	1.43	1.44	1.45	1.43	1.42	0.05
93/1Q	--	--	1.42	1.43	1.41	1.41	0.04
93/2Q	--	--	--	1.43	1.41	1.40	0.03
93/3Q	--	--	--	--	1.40	1.40	0.02
93/4Q	--	--	--	--	--	1.41	0.03
Actual	**1.40**	**1.40**	**1.38**	**1.39**	**1.38**	**1.38**	
Average Absolute Error	0.05	0.05	0.05	0.06	0.04	0.04	0.05
	(percent error)						
92/3Q	3.6	5.0	4.3	6.5	5.8	5.1	5.0
92/4Q	--	2.1	4.3	4.3	3.6	2.9	3.5
93/1Q	--	--	2.9	2.9	2.2	2.2	2.5
93/2Q	--	--	--	2.9	2.2	1.4	2.2
93/3Q	--	--	--	--	1.4	1.4	1.4
93/4Q	--	--	--	--	--	2.2	2.2
Average Absolute Percent Error	3.6	3.6	3.9	4.1	3.0	2.5	3.3

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A9. Real Disposable Personal Income, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(billion 1987 dollars)			
92/3Q	3609	3630	3642	3668	3689	3720	31
92/4Q	--	3588	3603	3625	3643	3673	77
93/1Q	--	--	3622	3643	3658	3694	46
93/2Q	--	--	--	3657	3660	3692	50
93/3Q	--	--	--	--	3666	3690	54
93/4Q	--	--	--	--	--	3687	69
Actual	**3625**	**3718**	**3642**	**3694**	**3708**	**3756**	
Average Absolute Error	16	109	20	46	45	63	51
				(percent error)			
92/3Q	-0.4	-2.4	0.0	-0.7	-0.5	-1.0	0.8
92/4Q	--	-3.5	-1.1	-1.9	-1.8	-2.2	2.1
93/1Q	--	--	-0.5	-1.4	-1.3	-1.7	1.2
93/2Q	--	--	--	-1.0	-1.3	-1.7	1.3
93/3Q	--	--	--	--	-1.1	-1.8	1.4
93/4Q	--	--	--	--	--	-1.8	1.8
Average Absolute Percent Error	0.4	2.9	0.5	1.2	1.2	1.7	1.4

-- = 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 1992, September 1992, January 1993, March 1993, July 1993, and September 1993.

Table A10. Industrial Production Index for Manufacturing, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(1987 = 1.000)			
92/3Q	1.079	1.096	1.106	1.115	1.126	1.140	0.005
92/4Q	--	1.090	1.101	1.114	1.129	1.145	0.004
93/1Q	--	--	1.088	1.101	1.111	1.120	0.014
93/2Q	--	--	--	1.113	1.124	1.135	0.004
93/3Q	--	--	--	--	1.129	1.141	0.005
93/4Q	--	--	--	--	--	1.132	0.009
Actual	**1.070**	**1.087**	**1.103**	**1.112**	**1.118**	**1.141**	
Average Absolute Error	0.009	0.006	0.007	0.004	0.009	0.007	0.007
				(percent error)			
92/3Q	0.8	0.8	0.3	0.2	0.8	-0.1	0.5
92/4Q	--	0.3	-0.2	0.2	1.0	0.4	0.4
93/1Q	--	--	-1.3	-1.0	-0.6	-1.9	1.2
93/2Q	--	--	--	0.1	0.5	-0.5	0.4
93/3Q	--	--	--	--	1.0	0.0	0.5
93/4Q	--	--	--	--	--	-0.8	0.8
Average Absolute Percent Error	0.8	0.5	0.6	0.4	0.8	0.6	0.6

-- = 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 1992, September 1992, January 1993, March 1993, July 1993, and September 1993.

Table A11. Heating Degree Days, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(Degree Days)						
92/3Q	88	1669	2401	536	88	1669	28
92/4Q	--	1669	2401	536	88	1669	26
93/1Q	--	--	2401	536	88	1669	31
93/2Q	--	--	--	536	88	1669	22
93/3Q	--	--	--	--	88	1669	28
93/4Q	--	--	--	--	--	1669	26
Actual	**127**	**1674**	**2342**	**527**	**118**	**1643**	
Average Absolute Error	39	5	59	9	30	26	27
	(percent error)						
92/3Q	-30.7	-0.3	2.5	1.7	-25.4	1.6	2.6
92/4Q	--	-0.3	2.5	1.7	-25.4	1.6	2.0
93/1Q	--	--	2.5	1.7	-25.4	1.6	2.7
93/2Q	--	--	--	1.7	-25.4	1.6	2.8
93/3Q	--	--	--	--	-25.4	1.6	3.2
93/4Q	--	--	--	--	--	1.6	1.6
Average Absolute Percent Error	30.7	0.3	2.5	1.7	25.4	1.6	8.7

-- = 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, 1951-1980.

Table A12. Cooling Degree Days, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(Degree Days)						
92/3Q	755	63	28	327	755	63	33
92/4Q	--	63	28	327	755	63	21
93/1Q	--	--	28	327	755	63	27
93/2Q	--	--	--	327	755	63	32
93/3Q	--	--	--	--	755	63	40
93/4Q	--	--	--	--	--	63	4
Actual	**665**	**62**	**17**	**312**	**831**	**59**	
Average Absolute Error	90	1	11	15	76	4	28
	(percent error)						
92/3Q	13.5	1.6	64.7	4.8	-9.1	6.8	10.1
92/4Q	--	1.6	64.7	4.8	-9.1	6.8	8.4

93/1Q	--	--	64.7	4.8	-9.1	6.8	8.7
93/2Q	--	--	--	4.8	-9.1	6.8	7.9
93/3Q	--	--	--	--	-9.1	6.8	9.0
93/4Q	--	--	--	--	--	6.8	6.8
Average Absolute Percent Error	13.5	1.6	64.7	4.8	9.1	6.8	15.1

-- = 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, 1951-1980.

Table A13. Total Petroleum Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
92/3Q	16.96	17.39	17.49	16.86	17.14	17.77	0.20
92/4Q	--	17.43	17.45	16.95	17.42	17.97	0.23
93/1Q	--	--	17.56	16.94	17.19	18.00	0.31
93/2Q	--	--	--	17.05	17.37	17.94	0.24
93/3Q	--	--	--	--	17.56	17.87	0.23
93/4Q	--	--	--	--	--	17.71	0.11
Actual	**17.04**	**17.58**	**17.13**	**16.68**	**17.36**	**17.60**	
Average Absolute Error	0.08	0.17	0.37	0.27	0.13	0.28	0.23
	(percent error)						
92/3Q	-0.5	-1.1	2.1	1.1	-1.3	1.0	1.2
92/4Q	--	-0.9	1.9	1.6	0.3	2.1	1.4
93/1Q	--	--	2.5	1.6	-1.0	2.3	1.8
93/2Q	--	--	--	2.2	0.1	1.9	1.4
93/3Q	--	--	--	--	1.2	1.5	1.3
93/4Q	--	--	--	--	--	0.6	0.6
Average Absolute Percent Error	0.5	1.0	2.2	1.6	0.8	1.6	1.4

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A14. Motor Gasoline Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
92/3Q	7.42	7.31	7.08	7.46	7.63	7.46	0.09
92/4Q	--	7.27	7.08	7.47	7.59	7.48	0.09
93/1Q	--	--	7.19	7.50	7.63	7.48	0.08
93/2Q	--	--	--	7.48	7.64	7.51	0.07
93/3Q	--	--	--	--	7.64	7.45	0.10
93/4Q	--	--	--	--	--	7.64	0.11

Actual	**7.58**	**7.41**	**7.09**	**7.54**	**7.76**	**7.53**	
Average Absolute Error	0.16	0.12	0.04	0.06	0.13	0.06	0.09
				(percent error)			
92/3Q	-2.1	-1.3	-0.1	-1.1	-1.7	-0.9	1.2
92/4Q	--	-1.9	-0.1	-0.9	-2.2	-0.7	1.2
93/1Q	--	--	1.4	-0.5	-1.7	-0.7	1.1
93/2Q	--	--	--	-0.8	-1.5	-0.3	0.9
93/3Q	--	--	--	--	-1.5	-1.1	1.3
93/4Q	--	--	--	--	--	1.5	1.5
Average Absolute Percent Error	2.1	1.6	0.6	0.8	1.7	0.8	1.1

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A15. Distillate Fuel Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(million barrels per day)			
92/3Q	2.68	3.18	3.49	2.90	2.73	3.25	0.10
92/4Q	--	3.17	3.45	2.95	2.84	3.27	0.09
93/1Q	--	--	3.47	2.94	2.81	3.28	0.10
93/2Q	--	--	--	2.95	2.83	3.28	0.09
93/3Q	--	--	--	--	2.83	3.25	0.04
93/4Q	--	--	--	--	--	3.15	0.03
Actual	**2.77**	**3.10**	**3.33**	**2.80**	**2.82**	**3.18**	
Average Absolute Error	0.09	0.07	0.14	0.14	0.03	0.08	0.09
				(percent error)			
92/3Q	-3.2	2.6	4.8	3.6	-3.2	2.2	3.3
92/4Q	--	2.3	3.6	5.4	0.7	2.8	3.0
93/1Q	--	--	4.2	5.0	-0.4	3.1	3.2
93/2Q	--	--	--	5.4	0.4	3.1	3.0
93/3Q	--	--	--	--	0.4	2.2	1.3
93/4Q	--	--	--	--	--	-0.9	0.9
Average Absolute Percent Error	3.2	2.4	4.2	4.8	1.0	2.4	2.8

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A16. Residual Fuel Oil Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	

	(million barrels per day)						
92/3Q	1.06	1.17	1.26	1.05	0.99	1.15	0.08
92/4Q	--	1.18	1.26	1.02	1.00	1.21	0.08
93/1Q	--	--	1.27	1.05	0.94	1.27	0.13
93/2Q	--	--	--	1.09	1.01	1.18	0.07
93/3Q	--	--	--	--	1.05	1.15	0.01
93/4Q	--	--	--	--	--	1.17	0.02
Actual	**0.94**	**1.16**	**1.07**	**0.98**	**1.07**	**1.15**	
Average Absolute Error	0.12	0.02	0.19	0.07	0.07	0.04	0.08
	(percent error)						
92/3Q	12.8	1.3	17.9	7.0	-7.5	0.0	7.5
92/4Q	--	2.2	17.9	4.0	-6.5	5.2	7.1
93/1Q	--	--	18.8	7.0	-12.1	10.4	12.2
93/2Q	--	--	--	11.1	-5.6	2.6	6.2
93/3Q	--	--	--	--	-1.9	0.0	0.9
93/4Q	--	--	--	--	--	1.7	1.7
Average Absolute Percent Error	12.8	1.7	18.2	7.3	6.7	3.3	7.3

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A17. Jet Fuel Demand (Product Supplied), Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
92/3Q	1.57	1.61	1.56	1.46	1.55	1.61	0.08
92/4Q	--	1.51	1.44	1.40	1.55	1.58	0.06
93/1Q	--	--	1.49	1.41	1.50	1.52	0.03
93/2Q	--	--	--	1.40	1.48	1.51	0.04
93/3Q	--	--	--	--	1.51	1.54	0.05
93/4Q	--	--	--	--	--	1.53	0.08
Actual	**1.49**	**1.52**	**1.48**	**1.44**	**1.49**	**1.45**	
Average Absolute Error	0.08	0.05	0.04	0.03	0.03	0.09	0.06
	(percent error)						
92/3Q	5.6	5.9	5.3	1.1	4.2	10.7	5.5
92/4Q	--	-0.7	-2.8	-3.0	4.2	8.7	3.8
93/1Q	--	--	0.5	-2.4	0.8	4.5	2.0
93/2Q	--	--	--	-3.0	-0.5	3.9	2.5
93/3Q	--	--	--	--	1.5	5.9	3.7
93/4Q	--	--	--	--	--	5.2	5.2
Average Absolute Percent Error	5.6	3.3	2.9	2.4	2.2	6.5	3.8

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A18. Other Petroleum Products Supplied, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
92/3Q	4.23	4.12	4.10	3.99	4.24	4.30	0.08
92/4Q	--	4.30	4.22	4.11	4.44	4.43	0.14
93/1Q	--	--	4.14	4.04	4.31	4.45	0.10
93/2Q	--	--	--	4.13	4.41	4.46	0.19
93/3Q	--	--	--	--	4.53	4.48	0.25
93/4Q	--	--	--	--	--	4.22	0.07
Actual	**4.26**	**4.40**	**4.16**	**3.91**	**4.22**	**4.29**	
Average Absolute Error	0.03	0.18	0.05	0.16	0.16	0.12	0.13
	(percent error)						
92/3Q	-0.7	-6.3	-1.3	2.1	0.4	0.2	1.9
92/4Q	--	-2.2	1.5	5.1	5.2	3.3	3.4
93/1Q	--	--	-0.4	3.4	2.1	3.7	2.4
93/2Q	--	--	--	5.7	4.5	4.0	4.7
93/3Q	--	--	--	--	7.3	4.4	5.9
93/4Q	--	--	--	--	--	-1.6	1.6
Average Absolute Percent Error	0.7	4.2	1.1	4.1	3.9	2.9	3.1

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A19. Domestic Crude Oil Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
92/3Q	7.07	7.12	7.06	6.94	6.88	6.91	0.09
92/4Q	--	7.16	7.12	6.98	6.93	6.97	0.15
93/1Q	--	--	7.06	6.92	6.86	6.89	0.10
93/2Q	--	--	--	6.84	6.74	6.82	0.03
93/3Q	--	--	--	--	6.83	6.83	0.07
93/4Q	--	--	--	--	--	6.81	0.04
Actual	**7.03**	**7.09**	**6.98**	**6.82**	**6.70**	**6.85**	
Average Absolute Error	0.04	0.06	0.10	0.10	0.15	0.05	0.09
	(percent error)						
92/3Q	0.6	0.5	1.1	1.7	2.7	0.9	1.3
92/4Q	--	1.1	2.0	2.3	3.4	1.8	2.1
93/1Q	--	--	1.1	1.5	2.4	0.6	1.4
93/2Q	--	--	--	0.3	0.6	-0.4	0.4
93/3Q	--	--	--	--	2.0	-0.2	1.1
93/4Q	--	--	--	--	--	-0.5	0.5
Average Absolute Percent Error	0.6	0.8	1.4	1.5	2.2	0.8	1.3

-- = Not applicable.
[P] = Preliminary.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A20. Lower 48 Crude Oil Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
92/3Q	5.45	5.45	5.45	5.38	5.34	5.33	0.10
92/4Q	--	5.45	5.46	5.39	5.35	5.35	0.12
93/1Q	--	--	5.40	5.33	5.28	5.27	0.06
93/2Q	--	--	--	5.26	5.20	5.19	0.01
93/3Q	--	--	--	--	5.20	5.19	0.01
93/4Q	--	--	--	--	--	5.19	0.00
Actual	**5.37**	**5.39**	**5.34**	**5.27**	**5.22**	**5.19**	
Average Absolute Error	0.08	0.06	0.10	0.07	0.07	0.06	0.07
	(percent error)						
92/3Q	1.6	1.1	2.1	2.1	2.3	2.6	1.9
92/4Q	--	1.1	2.2	2.2	2.5	3.0	2.2
93/1Q	--	--	1.1	1.1	1.2	1.5	1.2
93/2Q	--	--	--	-0.2	-0.4	-0.1	0.2
93/3Q	--	--	--	--	-0.4	-0.1	0.2
93/4Q	--	--	--	--	--	-0.1	0.1
Average Absolute Percent Error	1.6	1.1	1.8	1.4	1.3	1.2	1.4

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A21. Alaskan Crude Oil Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
92/3Q	1.62	1.67	1.60	1.56	1.54	1.58	0.04
92/4Q	--	1.71	1.66	1.58	1.58	1.62	0.04
93/1Q	--	--	1.67	1.59	1.58	1.63	0.05
93/2Q	--	--	--	1.58	1.54	1.63	0.04
93/3Q	--	--	--	--	1.62	1.67	0.08
93/4Q	--	--	--	--	--	1.62	0.03
Actual	**1.66**	**1.69**	**1.64**	**1.56**	**1.48**	**1.66**	
Average Absolute Error	0.04	0.02	0.03	0.02	0.09	0.04	0.04
	(percent error)						
92/3Q	-2.6	-1.3	-2.5	0.1	4.1	-4.5	2.5

92/4Q	--	1.1	1.2	1.4	6.8	-2.1	2.4
93/1Q	--	--	1.8	2.1	6.8	-1.5	2.9
93/2Q	--	--	--	1.4	4.1	-1.5	2.3
93/3Q	--	--	--	--	9.5	0.9	4.9
93/4Q	--	--	--	--	--	-2.1	2.1
Average Absolute Percent Error	2.6	1.2	1.8	1.3	6.2	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(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A22. Net Oil Imports, Actual Versus Forecasts (Excluding SPR)

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels per day)						
92/3Q	7.54	7.50	7.05	7.61	7.92	7.82	0.15
92/4Q	--	7.31	6.73	7.66	8.01	7.77	0.20
93/1Q	--	--	6.95	7.59	7.74	7.92	0.08
93/2Q	--	--	--	7.81	8.08	7.93	0.26
93/3Q	--	--	--	--	8.21	7.96	0.32
93/4Q	--	--	--	--	--	7.64	0.15
Actual	**7.45**	**7.03**	**7.04**	**7.51**	**7.75**	**7.79**	
Average Absolute Error	0.09	0.37	0.14	0.16	0.25	0.11	0.18
	(percent error)						
92/3Q	1.2	6.7	0.1	1.3	2.2	0.4	2.0
92/4Q	--	4.0	-4.4	2.0	3.4	-0.3	2.7
93/1Q	--	--	-1.3	1.1	-0.1	1.7	1.0
93/2Q	--	--	--	4.0	4.3	1.8	3.3
93/3Q	--	--	--	--	5.9	2.2	4.1
93/4Q	--	--	--	--	--	-1.9	1.9
Average Absolute Percent Error	1.2	5.3	1.9	2.1	3.2	1.4	2.4

-- = 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(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A23. Total Petroleum Stocks, Actual Versus Forecasts (Excluding SPR)

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(million barrels)						
92/3Q	1074	1070	1007	1038	1076	1066	19
92/4Q	--	1063	993	1035	1070	1050	23
93/1Q	--	--	1005	1041	1075	1059	10
93/2Q	--	--	--	1049	1082	1064	13

93/3Q	--	--	--	--	1092	1072	15
93/4Q	--	--	--	--	--	1063	4
Actual	**1064**	**1017**	**1006**	**1078**	**1076**	**1059**	
Average Absolute Error	10	50	5	37	6	6	16
				(percent error)			
92/3Q	0.9	5.2	0.1	-3.7	0.0	0.7	1.8
92/4Q	--	4.5	-1.3	-4.0	-0.6	-0.8	2.2
93/1Q	--	--	-0.1	-3.4	-0.1	0.0	0.9
93/2Q	--	--	--	-2.7	0.6	0.5	1.2
93/3Q	--	--	--	--	1.5	1.2	1.4
93/4Q	--	--	--	--	--	0.4	0.4
Average Absolute Percent Error	0.9	4.9	0.5	3.5	0.5	0.6	1.5

-- = 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(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A24. Natural Gas Demand, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(trillion cubic feet)			
92/3Q	4.02	5.38	6.90	4.64	4.12	5.52	0.25
92/4Q	--	5.17	6.57	4.78	4.03	5.29	0.13
93/1Q	--	--	6.56	4.71	4.00	5.10	0.17
93/2Q	--	--	--	4.70	4.01	5.14	0.19
93/3Q	--	--	--	--	4.00	5.23	0.02
93/4Q	--	--	--	--	--	5.07	0.17
Actual	**3.82**	**5.16**	**6.60**	**4.24**	**4.03**	**5.24**	
Average Absolute Error	0.20	0.30	0.14	0.45	0.06	0.19	0.21
				(percent error)			
92/3Q	5.1	4.3	4.5	9.4	2.2	5.1	5.1
92/4Q	--	0.2	-0.5	12.7	0.0	1.0	2.5
93/1Q	--	--	-0.6	11.1	-0.7	-2.7	3.4
93/2Q	--	--	--	10.8	-0.5	-1.9	4.3
93/3Q	--	--	--	--	-0.7	-0.2	0.4
93/4Q	--	--	--	--	--	-3.2	3.2
Average Absolute Percent Error	5.1	2.2	1.9	11.0	0.8	2.4	3.7

-- = Not applicable.
P = Preliminary.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A25. Natural Gas Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	

Forecast Report	1992 3rd	1992 4th	1993 1st	1993 2nd	1993 3rd	1993 4th	Average Absolute Error
				(trillion cubic feet)			
92/3Q	4.57	4.90	4.95	4.67	4.59	4.95	0.20
92/4Q	--	4.83	4.72	4.65	4.64	4.78	0.11
93/1Q	--	--	4.69	4.54	4.53	4.82	0.05
93/2Q	--	--	--	4.57	4.52	4.82	0.05
93/3Q	--	--	--	--	4.59	4.70	0.03
93/4Q	--	--	--	--	--	4.71	0.01
Actual	**4.38**	**4.63**	**4.62**	**4.55**	**4.55**	**4.72**	
Average Absolute Error	0.19	0.24	0.17	0.06	0.04	0.09	0.10
				(percent error)			
92/3Q	4.3	5.8	7.1	2.6	0.9	4.9	4.3
92/4Q	--	4.3	2.2	2.2	2.0	1.3	2.4
93/1Q	--	--	1.5	-0.2	-0.4	2.1	1.1
93/2Q	--	--	--	0.4	-0.7	2.1	1.1
93/3Q	--	--	--	--	0.9	-0.4	0.6
93/4Q	--	--	--	--	--	-0.2	0.2
Average Absolute Percent Error	4.3	5.1	3.6	1.4	1.0	1.8	2.2

-- = Not applicable.
P = Preliminary.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A26. Domestic Coal Consumption, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(million tons)			
92/3Q	238.0	228.0	233.0	215.0	243.0	233.0	3.0
92/4Q	--	229.0	224.0	224.0	234.0	237.0	8.0
93/1Q	--	--	226.1	218.3	238.0	227.7	5.6
93/2Q	--	--	--	219.3	239.4	229.5	5.9
93/3Q	--	--	--	--	236.0	229.5	8.6
93/4Q	--	--	--	--	--	229.5	2.5
Actual	**237.7**	**224.1**	**229.7**	**215.8**	**250.7**	**232.0**	
Average Absolute Error	0	4	4	4	13	3	6
				(percent error)			
92/3Q	0.1	1.7	1.4	-0.4	-3.1	0.4	1.3
92/4Q	--	2.2	-2.5	3.8	-6.7	2.2	3.5
93/1Q	--	--	-1.6	1.2	-5.1	-1.9	2.4
93/2Q	--	--	--	1.8	-4.5	-1.1	2.5
93/3Q	--	--	--	--	-5.9	-1.1	3.6
93/4Q	--	--	--	--	--	-1.1	1.1
Average Absolute Percent Error	0.1	2.0	1.8	1.8	5.0	1.0	2.3

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(93/4Q); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A27. Coal Production, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(million tons)			
92/3Q	254.0	261.0	259.0	249.0	258.0	265.0	17.3
92/4Q	--	257.0	254.0	248.0	258.0	268.0	18.3
93/1Q	--	--	254.2	250.2	253.4	261.1	18.8
93/2Q	--	--	--	249.6	254.8	260.7	21.2
93/3Q	--	--	--	--	253.9	256.1	21.7
93/4Q	--	--	--	--	--	246.8	7.8
Actual	**249.1**	**249.8**	**242.5**	**234.9**	**227.7**	**239.0**	
Average Absolute Error	4.9	9.2	13.2	14.3	27.9	20.6	18.3
				(percent error)			
92/3Q	2.0	4.5	6.8	6.0	13.3	10.9	7.2
92/4Q	--	2.9	4.7	5.6	13.3	12.1	7.7
93/1Q	--	--	4.8	6.5	11.3	9.2	8.0
93/2Q	--	--	--	6.3	11.9	9.1	9.1
93/3Q	--	--	--	--	11.5	7.2	9.3
93/4Q	--	--	--	--	--	3.3	3.3
Average Absolute Percent Error	2.0	3.7	5.5	6.1	12.3	8.6	7.8

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(93/4Q); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A28. Total Electricity Sales, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(billion kilowatthours)			
92/3Q	757.6	680.4	723.6	679.2	777.4	699.6	11.4
92/4Q	--	682.9	706.1	680.9	762.3	702.6	12.4
93/1Q	--	--	701.9	677.6	757.5	697.0	14.3
93/2Q	--	--	--	681.5	761.6	701.3	19.2
93/3Q	--	--	--	--	758.8	698.4	22.5
93/4Q	--	--	--	--	--	701.7	9.2
Actual	**746.1**	**679.4**	**705.5**	**668.9**	**797.9**	**692.5**	
Average Absolute Error	11.5	2.3	7.4	10.9	34.4	7.6	14.3
				(percent error)			
92/3Q	1.5	0.1	2.6	1.5	-2.6	1.0	1.6
92/4Q	--	0.5	0.1	1.8	-4.5	1.5	1.8
93/1Q	--	--	-0.5	1.3	-5.1	0.6	2.0
93/2Q	--	--	--	1.9	-4.5	1.3	2.7
93/3Q	--	--	--	--	-4.9	0.9	3.0
93/4Q	--	--	--	--	--	1.3	1.3
Average Absolute Percent Error	1.5	0.3	1.1	1.6	4.3	1.1	1.9

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A29. Residential Electricity Sales, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(billion kilowatthours)						
92/3Q	269.6	228.4	269.9	218.4	275.3	233.8	8.4
92/4Q	--	230.9	258.2	225.0	267.2	236.1	9.9
93/1Q	--	--	255.6	223.2	264.7	234.3	11.9
93/2Q	--	--	--	222.2	263.6	233.3	14.0
93/3Q	--	--	--	--	263.8	233.6	15.0
93/4Q	--	--	--	--	--	234.7	2.8
Actual	**256.7**	**227.6**	**260.2**	**210.1**	**292.1**	**231.9**	
Average Absolute Error	12.9	2.1	5.4	12.1	25.2	2.4	10.6
	(percent error)						
92/3Q	5.0	0.4	3.7	4.0	-5.8	0.8	3.4
92/4Q	--	1.4	-0.8	7.1	-8.5	1.8	4.0
93/1Q	--	--	-1.8	6.2	-9.4	1.0	4.8
93/2Q	--	--	--	5.8	-9.8	0.6	5.7
93/3Q	--	--	--	--	-9.7	0.7	5.7
93/4Q	--	--	--	--	--	1.2	1.2
Average Absolute Percent Error	5.0	0.9	2.1	5.8	8.6	1.0	4.1

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A30. Commercial Electricity Sales, Actual Versus Forecasts

Forecast Report	Forecast Quarter						Average Absolute Error
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(billion kilowatthours)						
92/3Q	214.9	188.4	192.7	191.6	222.1	195.3	3.6
92/4Q	--	189.7	189.2	190.4	217.5	196.2	3.8
93/1Q	--	--	186.6	187.7	214.4	193.0	3.3
93/2Q	--	--	--	189.0	215.9	194.2	3.9
93/3Q	--	--	--	--	217.3	195.8	5.9
93/4Q	--	--	--	--	--	195.7	5.0
Actual	**210.1**	**186.6**	**186.7**	**189.0**	**224.0**	**190.7**	
Average Absolute Error	4.8	2.5	2.9	1.3	6.6	4.3	3.9
	(percent error)						
92/3Q	2.3	1.0	3.2	1.4	-0.8	2.4	1.8

92/4Q	--	1.7	1.3	0.7	-2.9	2.9	1.9
93/1Q	--	--	-0.1	-0.7	-4.3	1.2	1.7
93/2Q	--	--	--	0.0	-3.6	1.8	1.9
93/3Q	--	--	--	--	-3.0	2.7	2.8
93/4Q	--	--	--	--	--	2.6	2.6
Average Absolute Percent Error	2.3	1.3	1.5	0.7	2.9	2.3	1.9

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A31. Industrial Electricity Sales, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(billion kilowatthours)			
92/3Q	239.8	248.5	240.4	237.2	246.1	254.9	9.1
92/4Q	--	239.1	235.4	242.6	253.1	246.9	2.4
93/1Q	--	--	236.2	243.8	253.9	246.2	1.7
93/2Q	--	--	--	247.4	257.5	250.3	2.3
93/3Q	--	--	--	--	252.7	245.3	1.9
93/4Q	--	--	--	--	--	250.9	5.1
Actual	**254.3**	**242.3**	**234.6**	**246.5**	**256.0**	**245.8**	
Average Absolute Error	14.5	4.7	2.7	4.2	3.9	3.4	4.3
				(percent error)			
92/3Q	-5.7	2.6	2.5	-3.8	-3.9	3.7	3.7
92/4Q	--	-1.3	0.3	-1.6	-1.1	0.4	1.0
93/1Q	--	--	0.7	-1.1	-0.8	0.2	0.7
93/2Q	--	--	--	0.4	0.6	1.8	0.9
93/3Q	--	--	--	--	-1.3	-0.2	0.8
93/4Q	--	--	--	--	--	2.1	2.0
Average Absolute Percent Error	5.7	1.9	1.2	1.7	1.5	1.4	1.7

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A32. Electricity Generation from Coal, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(billion kilowatthours)			
92/3Q	421.1	394.9	406.2	373.0	430.1	404.7	5.7
92/4Q	--	398.7	389.9	396.1	410.4	414.2	16.9
93/1Q	--	--	394.6	385.2	420.8	395.7	13.9
93/2Q	--	--	--	388.4	423.9	399.5	13.9
93/3Q	--	--	--	--	417.5	400.5	18.7
93/4Q	--	--	--	--	--	401.5	5.5

Actual	**424.2**	**391.7**	**404.7**	**378.7**	**448.4**	**407.0**	
Average Absolute Error	3.1	5.1	8.8	9.8	27.7	6.7	12.3
				(percent error)			
92/3Q	-0.7	0.8	0.4	-1.5	-4.1	-0.6	1.4
92/4Q	--	1.8	-3.7	4.6	-8.5	1.8	4.2
93/1Q	--	--	-2.5	1.7	-6.2	-2.8	3.4
93/2Q	--	--	--	2.6	-5.5	-1.8	3.4
93/3Q	--	--	--	--	-6.9	-1.6	4.4
93/4Q	--	--	--	--	--	-1.4	1.4
Average Absolute Percent Error	-0.7	1.3	2.2	2.6	6.2	1.7	2.9

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A33. Electricity Generation from Petroleum, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(billion kilowatthours)			
92/3Q	27.1	24.0	26.6	27.3	27.6	24.8	4.6
92/4Q	--	24.1	26.2	23.2	27.3	26.2	3.8
93/1Q	--	--	26.4	25.0	23.7	27.7	5.5
93/2Q	--	--	--	26.5	27.2	22.4	5.7
93/3Q	--	--	--	--	27.0	22.0	4.8
93/4Q	--	--	--	--	--	20.3	5.1
Actual	**22.3**	**20.1**	**22.7**	**18.3**	**33.1**	**25.4**	
Average Absolute Error	4.8	3.9	3.7	7.2	6.5	2.5	4.8
				(percent error)			
92/3Q	21.5	19.4	17.2	49.2	-16.6	-2.4	19.5
92/4Q	--	19.9	15.4	26.8	-17.5	3.1	15.9
93/1Q	--	--	16.3	36.6	-28.4	9.1	22.2
93/2Q	--	--	--	44.8	-17.8	-11.8	22.3
93/3Q	--	--	--	--	-18.4	-13.4	16.2
93/4Q	--	--	--	--	--	-20.1	20.1
Average Absolute Percent Error	21.5	19.7	16.3	39.3	19.8	10.0	20.3

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A34. Electricity Generation from Natural Gas, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(billion kilowatthours)			

92/3Q	91.7	61.8	56.0	76.3	93.1	63.2	6.9
92/4Q	--	64.5	52.3	79.4	86.4	64.4	8.4
93/1Q	--	--	56.5	76.6	88.6	59.9	7.3
93/2Q	--	--	--	75.0	88.3	58.6	7.7
93/3Q	--	--	--	--	85.9	58.6	3.6
93/4Q	--	--	--	--	--	59.6	1.1
Actual	**86.8**	**55.2**	**50.3**	**56.8**	**91.0**	**60.7**	
Average Absolute Error	4.9	7.9	4.6	20.0	3.4	2.1	6.9
				(percent error)			
92/3Q	5.6	12.0	11.3	34.3	2.3	4.1	10.3
92/4Q	--	16.8	4.0	39.8	-5.1	6.1	13.4
93/1Q	--	--	12.3	34.9	-2.6	-1.3	11.3
93/2Q	--	--	--	32.0	-3.0	-3.5	11.0
93/3Q	--	--	--	--	-5.6	-3.5	4.7
93/4Q	--	--	--	--	--	-1.8	1.8
Average Absolute Percent Error	5.6	14.4	9.2	35.3	3.7	3.4	11.5

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A35. Electricity Generation from Nuclear Power, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
				(billion kilowatthours)			
92/3Q	165.8	147.1	162.1	141.1	167.0	149.1	5.0
92/4Q	--	151.3	159.3	139.1	164.6	147.0	4.0
93/1Q	--	--	154.1	138.4	169.4	148.1	5.3
93/2Q	--	--	--	137.0	167.7	155.1	8.3
93/3Q	--	--	--	--	170.7	156.8	10.2
93/4Q	--	--	--	--	--	159.8	15.4
Actual	**165.6**	**157.6**	**157.0**	**146.2**	**162.7**	**144.4**	
Average Absolute Error	0.2	8.4	3.4	7.3	5.2	8.2	6.3
				(percent error)			
92/3Q	0.1	-6.7	3.2	-3.5	2.6	3.3	3.2
92/4Q	--	-4.0	1.5	-4.9	1.2	1.8	2.6
93/1Q	--	--	-1.8	-5.3	4.1	2.6	3.5
93/2Q	--	--	--	-6.3	3.1	7.4	5.5
93/3Q	--	--	--	--	4.9	8.6	6.6
93/4Q	--	--	--	--	--	10.7	10.7
Average Absolute Percent Error	0.1	5.3	2.2	5.0	3.2	5.7	4.2

-- = Not applicable.
Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Table A36. Electricity Generation from Hydroelectric Power, Actual Versus Forecasts

Forecast Report	Forecast Quarter						**Average Absolute Error**
	1992		1993				
	3rd	4th	1st	2nd	3rd	4th	
	(billion kilowatthours)						
92/3Q	63.0	67.2	73.6	79.7	66.6	68.9	7.1
92/4Q	--	63.2	71.1	78.9	66.6	68.9	5.7
93/1Q	--	--	67.1	76.6	65.6	66.8	5.4
93/2Q	--	--	--	76.6	65.6	66.8	6.9
93/3Q	--	--	--	--	64.1	64.2	6.1
93/4Q	--	--	--	--	--	66.2	10.3
Actual	**54.6**	**59.5**	**67.8**	**81.1**	**60.3**	**55.9**	
Average Absolute Error	8.4	5.7	3.3	3.1	5.4	11.1	6.5
	(percent error)						
92/3Q	15.4	12.9	8.6	-1.7	10.4	23.3	11.2
92/4Q	--	6.2	4.9	-2.7	10.4	23.3	8.8
93/1Q	--	--	-1.0	-5.5	8.8	19.5	8.1
93/2Q	--	--	--	-5.5	8.8	19.5	10.5
93/3Q	--	--	--	--	6.3	14.8	10.4
93/4Q	--	--	--	--	--	18.4	18.4
Average Absolute Percent Error	15.4	9.6	4.8	3.9	9.0	19.8	10.9

-- = Not applicable.

Sources: Actual data are based on published numbers from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/04); forecasts are taken from the base or mid-case scenarios of the *Short-Term Energy Outlook.*

Appendix B

Regression Results

Table B1. Pentanes Plus Product Supplied (Demand)
(PPTCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PPTCPUS	15	105	0.06717	0.0006398	0.02529	0.5888	0.5340	2.079

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PPTC_B0	-0.212644	0.15524	-1.37	0.1737	PPTCPUS constant coefficient
PPTC_MG	0.547097	0.33736	1.62	0.1079	PPTCPUS coef of MGYLD
PPTC_T	0.000720	0.0000898	8.02	0.0001	PPTCPUS coef of TIME
PPTC_E1	-0.005002	0.01024	-0.49	0.6260	PPTCPUS coef of JAN
PPTC_E2	-0.012745	0.01137	-1.12	0.2648	PPTCPUS coef of FEB
PPTC_E3	-0.017347	0.01162	-1.49	0.1385	PPTCPUS coef of MAR
PPTC_E4	-0.031451	0.01192	-2.64	0.0096	PPTCPUS coef of APR
PPTC_E5	-0.018762	0.01221	-1.54	0.1275	PPTCPUS corf of MAY
PPTC_E6	-0.026734	0.01198	-2.23	0.0278	PPTCPUS coef of JUN
PPTC_E7	-0.025379	0.01192	-2.13	0.0356	PPTCPUS coef of JUL
PPTC_E8	-0.023471	0.01176	-2.00	0.0485	PPTCPUS coef of AUG
PPTC_E9	-0.015142	0.01168	-1.30	0.1979	PPTCPUS coef of SEP
PPTC_E10	0.004492	0.01148	0.39	0.6963	PPTCPUS coef of OCT
PPTC_E11	0.004518	0.01006	0.45	0.6544	PPTCPUS coef of NOV
PPTC_L1	0.260333	0.09473	2.75	0.0071	PPTCPUS 1st-order autocorrelation coefficient

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8401 TO 9312

Table B2. Unfinished Oils Product Supplied (Demand)
(UOTCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
UOTCPUS	13	107	0.43213	0.0040386	0.06355	0.2011	0.1116	1.894

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
UOTC_B0	-0.068931	0.03685	-1.87	0.0641	UOTCPUS constant coefficient
UOTC_RI	-0.150699	0.04063	-3.71	0.0003	UOTCPUS coef of UORIPUS
UOTC_E1	-0.012050	0.03128	-0.39	0.7008	UOTCPUS coef of JAN
UOTC_E2	-0.027179	0.03179	-0.85	0.3944	UOTCPUS coef of FEB
UOTC_E3	-0.016166	0.03338	-0.48	0.6292	UOTCPUS coef of MAR
UOTC_E4	0.002338	0.03086	0.08	0.9398	UOTCPUS coef of APR
UOTC_E5	-0.044486	0.03030	-1.47	0.1450	UOTCPUS corf of MAY
UOTC_E6	-0.019900	0.02913	-0.68	0.4960	UOTCPUS coef of JUN
UOTC_E7	-0.022693	0.02873	-0.79	0.4314	UOTCPUS coef of JUL
UOTC_E8	-0.024628	0.02932	-0.84	0.4028	UOTCPUS coef of AUG
UOTC_E9	-0.022036	0.02992	-0.74	0.4630	UOTCPUS coef of SEP
UOTC_E10	-0.018533	0.03080	-0.60	0.5486	UOTCPUS coef of OCT
UOTC_E11	-0.040309	0.02907	-1.39	0.1685	UOTCPUS coef of NOV

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9312

Table B3. Petrochemical Feedstocks Product Supplied (Demand)
(FETCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
FETCPUS	15	105	0.17449	0.0016618	0.04077	0.8002	0.7736	2.164

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
FETC_B0	-0.271142	0.08928	-3.04	0.0030	FETCPUS constant coefficient
FETC_ZO	0.736889	0.07724	9.54	0.0001	FETCPUS coef of ZO28IUS
FETC_PR	-0.060874	0.03689	-1.65	0.1019	FETCPUS coef of MGWHUUSX/PRTCUUS
FETC_E1	0.020518	0.01531	1.34	0.1832	FETCPUS coef of JAN
FETC_E2	0.019076	0.01840	1.04	0.3022	FETCPUS coef of FEB
FETC_E3	0.056533	0.01968	2.87	0.0049	FETCPUS coef of MAR
FETC_E4	0.057643	0.02078	2.77	0.0066	FETCPUS coef of APR
FETC_E5	0.055993	0.02215	2.53	0.0130	FETCPUS corf of MAY
FETC_E6	0.082687	0.02248	3.68	0.0004	FETCPUS coef of JUN
FETC_E7	0.077797	0.02206	3.53	0.0006	FETCPUS coef of JUL
FETC_E8	0.046730	0.02170	2.15	0.0336	FETCPUS coef of AUG
FETC_E9	0.029132	0.02066	1.41	0.1615	FETCPUS coef of SEP
FETC_E10	0.000742	0.01910	0.04	0.9691	FETCPUS coef of OCT
FETC_E11	0.003804	0.01540	0.25	0.8053	FETCPUS coef of NOV
FETC_L1	0.497708	0.08505	5.85	0.0001	FETCPUS 1st-order autocorrelation coefficient

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8401 TO 9312

Table B4. Petroleum Coke Product Supplied (Demand)
(PCTCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
PCTCPUS	13	107	0.13444	0.0012565	0.03545	0.6047	0.5604	1.747

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
PCTC_B0	0.107609	0.01981	5.43	0.0001	PCTCPUS constant coefficient
PCTC_T	0.001156	0.000094	12.32	0.0001	PCTCPUS coef of TIME
PCTC_E1	0.024828	0.01589	1.56	0.1785	PCTCPUS coef of JAN
PCTC_E2	0.000052	0.01588	0.00	0.8623	PCTCPUS coef of FEB
PCTC_E3	0.016065	0.01587	1.01	0.4197	PCTCPUS coef of MAR
PCTC_E4	-0.008056	0.01587	-0.51	0.4991	PCTCPUS coef of APR
PCTC_E5	0.013611	0.01587	0.86	0.5145	PCTCPUS coef of MAY
PCTC_E6	0.007558	0.01586	0.48	0.7811	PCTCPUS coef of JUN
PCTC_E7	0.001290	0.01586	0.08	0.9126	PCTCPUS coef of JUL
PCTC_E8	0.032574	0.01586	2.05	0.0724	PCTCPUS coef of AUG
PCTC_E9	-0.001151	0.01585	-0.07	0.7912	PCTCPUS coef of SEP
PCTC_E10	0.004406	0.01585	0.28	0.6423	PCTCPUS coef of OCT
PCTC_E11	0.010384	0.01585	0.66	0.6303	PCTCPUS coef of NOV

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9312

Table B5. Asphalt and Road Oil Product Supplied (Demand)
(ARTCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
ARTCPUS	15	129	0.13767	0.0010672	0.03267	0.9780	0.9756	1.508

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
ARTC_B0	-0.330364	0.06264	-5.27	0.0001	ARTCPUS constant coefficient
ARTC_ZO	0.607364	0.09046	6.71	0.0001	ARTCPUS coef of ZOTOIUS
ARTC_ZW	-0.004933	0.00154	-3.21	0.0017	ARTCPUS coef of ZWHDDUS/ZSAJQUS
ARTC_T	-0.000437	0.000194	-2.25	0.0259	ARTCPUS coef of TIME
ARTC_E1	-0.049924	0.01345	-3.71	0.0003	ARTCPUS coef of JAN
ARTC_E2	-0.024329	0.01348	-1.80	0.0734	ARTCPUS coef of FEB
ARTC_E3	0.030837	0.01336	2.31	0.0226	ARTCPUS coef of MAR
ARTC_E4	0.148402	0.01335	11.12	0.0001	ARTCPUS coef of APR
ARTC_E5	0.280241	0.01335	21.00	0.0001	ARTCPUS coef of MAY
ARTC_E6	0.434396	0.01335	32.55	0.0001	ARTCPUS coef of JUN
ARTC_E7	0.459809	0.01334	34.46	0.0001	ARTCPUS coef of JUL
ARTC_E8	0.511654	0.01334	38.35	0.0001	ARTCPUS coef of AUG
ARTC_E9	0.461161	0.01334	34.56	0.0001	ARTCPUS coef of SEP
ARTC_E10	0.365854	0.01334	27.42	0.0001	ARTCPUS coef of OCT
ARTC_E11	0.166199	0.01334	12.46	0.0001	ARTCPUS coef of NOV

Method of Estimation: OLS
RANGE of Fit: 8201 TO 9312

Table B6. Other Miscellaneous Petroleum Products Supplied (Demand)
(MZTCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
MZTCPUS	15	105	0.09964	0.0009489	0.03080	0.7780	0.7484	1.833

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
MZTC_B0	0.366041	0.07398	4.95	0.0001	MZTCPUS constant coefficient
MZTC_ZO	0.409057	0.10333	3.96	0.0001	MZTCPUS coef of ZOMNIUS
MZTC_ZW	0.004969	0.00163	3.05	0.0029	MZTCPUS coef of ZWHDDUS/ZSAJQUS
MZTC_T	-0.002135	0.000214	-9.99	0.0001	MZTCPUS coef of TIME
MZTC_E1	0.023258	0.01398	1.66	0.0993	MZTCPUS coef of JAN
MZTC_E2	0.019531	0.01394	1.40	0.1641	MZTCPUS coef of FEB
MZTC_E3	-0.002174	0.01381	-0.16	0.8752	MZTCPUS coef of MAR
MZTC_E4	-0.027295	0.01380	-1.98	0.0506	MZTCPUS coef of APR
MZTC_E5	-0.027803	0.01379	-2.02	0.0464	MZTCPUS coef of MAY
MZTC_E6	-0.039336	0.01379	-2.85	0.0052	MZTCPUS coef of JUN
MZTC_E7	-0.054484	0.01379	-3.95	0.0001	MZTCPUS coef of JUL
MZTC_E8	-0.031601	0.01379	-2.29	0.0239	MZTCPUS coef of AUG
MZTC_E9	-0.029929	0.01380	-2.17	0.0323	MZTCPUS coef of SEP
MZTC_E10	-0.019956	0.01380	-1.45	0.1511	MZTCPUS coef of OCT
MZTC_E11	-0.005079	0.01379	-0.37	0.7135	MZTCPUS coef of NOV

Method of Estimation: OLS
RANGE of Fit: 8401 TO 9312

Table B7. Still Gas Product Supplied (Demand)
(SGTCPUS)

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Sq	Durbin-Watson
SGTCPUS	16	128	0.02749	0.0002148	0.01466	0.9439	0.9374	2.131

Parameter	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob>|T|	Label
SGTC_B0	-0.215799	0.11024	-1.96	0.0525	SGTCPUS constant coefficient
SGTC_CO	0.039073	0.00472	8.28	0.0001	SGTCPUS coef of CORIPUS
SGTC_MG	0.636850	0.18583	3.43	0.0008	SGTCPUS coef of MGYLD
SGTC_D1	0.054789	0.00947	5.79	0.0001	SGTCPUS coef of D86ON
SGTC_E1	-0.000276	0.00487	-0.06	0.9549	SGTCPUS coef of JAN
SGTC_E2	0.006184	0.00634	0.98	0.3311	SGTCPUS coef of FEB
SGTC_E3	0.005532	0.00702	0.79	0.4323	SGTCPUS coef of MAR
SGTC_E4	0.015615	0.00723	2.16	0.0326	SGTCPUS coef of APR
SGTC_E5	0.015501	0.00763	2.03	0.0443	SGTCPUS corf of MAY
SGTC_E6	0.032094	0.00804	3.99	0.0001	SGTCPUS coef of JUN
SGTC_E7	0.033600	0.00795	4.22	0.0001	SGTCPUS coef of JUL
SGTC_E8	0.032776	0.00748	4.38	0.0001	SGTCPUS coef of AUG
SGTC_E9	0.020014	0.00697	2.87	0.0048	SGTCPUS coef of SEP
SGTC_E10	-0.006565	0.00609	-1.08	0.2831	SGTCPUS coef of OCT

SGTC_E11	-0.008772	0.00457	-1.92	0.0574	SGTCPUS coef of NOV
SGTC_L1	0.717458	0.06261	11.46	0.0001	SGTCPUS 1st-order autocorrelation coefficient

Method of Estimation: OLS with 1st-order autocorrelation correction
RANGE of Fit: 8201 TO 9312