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Petroleum 1996

Issues and Trends

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Energy Information Administration
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Preface

Contacts

Petroleum 1996: Issues and Trends was prepared by the Energy Information Administration (EIA) Office of Oil and Gas, Kenneth A. Vagts, Director (202/586-6401), and the EIA Office of Energy Markets and End Use, Webster C. Kilgore, Director (202/586-1617). Specific information concerning the report may be obtained from Craig H. Cranston, Acting Chief of the Publication and Analysis Branch (Telephone: 202/586-6023; Fax: 202/586-4913; E-mail: craig.cranston@eia.doe.gov) or from Charles P. Shirkey (202/586-6567).

Primary analytical contributions to the report were made by the following individuals:

Chapter 1 **-** Charles Dale and Joanne Shore;
Chapter 2 **-** Joanne Shore;
Chapter 3 **-** David Morehouse;
Chapter 4 **-** Heather Rowland;
Chapter 5 **-** Aileen Bohn;
Chapter 6 **-** Charles Dale and John Zyren;
Chapter 7 **-** John Hackworth and Joanne Shore; and
Chapter 8 **-** Jon Rasmussen.

Significant analytical contributions were also made by Laura Knight and John Ostrich.

Editorial support was provided by Dick Richards. Desktop publishing support was provided by Margareta Bennett.

Future Analysis

This report addresses the phenomenon of volatility, which involves every aspect of the petroleum sector to differing degrees. More analysis of this and other petroleum-related topics can be conducted using the combination of data collected by EIA and available trade data. What EIA will address in the future, and how, depends on both market developments and on you, customers of the Energy Information Administration and users of this first edition of *Petroleum 1996: Issues and Trends*. You are invited to convey to any of the contributors listed in the Contacts section above your reaction to this report and your thoughts with respect to future petroleum analysis.

For further information concerning analysis of petroleum and other energy issues, see the Energy Information Administration's home page on the World Wide Web at **http://www.eia.doe.gov**.

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Purpose of the Report

Increasingly, users of the Energy Information Administration's petroleum data and analytical reports have expressed an interest in a recurring report that takes a broad view of the petroleum sector. What is sought is some perspective on the complex interrelationships that comprise an industry and markets accounting for 40 percent of the energy consumed in the United States and ranging from the drilling rig in the oil field to the pump at the local gasoline station.

This report comprehensively examines historical ***trends***, and selectively focuses on major ***issues*** and the events they represent. It analyzes different dimensions of the industry and related markets in terms of how they relate to a common theme, in this case, the volatility in petroleum markets.

Theme — Volatility

One notable development in petroleum product markets has been volatility, as reflected in the rapid and conspicuous change in petroleum product prices. An instance of volatility, the turbulence in motor gasoline wholesale and retail markets in the spring of 1996, made this a matter of national concern. At the time, the Energy Information Administration co-authored a report undertaken at the request of President Clinton, which examined the market conditions that impacted the supply-demand balance leading up to the motor gasoline season, and how the wholesale, commodity, and retail markets responded.[*] In a sense, this report, *Petroleum 1996: Issues and Trends*, picks up where that report left off.

More recently, the issue of volatility in petroleum markets was addressed by Secretary of Energy Federico Peña in a message to Department of Energy employees throughout the country on the day after he was sworn into office. In outlining the first of four priorities for the Department, Secretary Peña underscored a major long-term source of uncertainty in the world supply/demand balance:

> "First, we will develop a realistic strategy for strengthening our nation's energy security. Recent history has demonstrated how vulnerable we are to a disruption in the flow of imported oil or volatility in its price."[**]

The volatility, the sharp and rapid fluctuation, in oil prices is a symptom of a combination of underlying market developments. Sharp price movements reflect a high level of uncertainty in all sectors of supply and their associated markets. Thus, more insight may be gleaned from assessment of the supply and demand conditions that led to the shift in prices, in addition to analyzing the impacts on participants in the petroleum markets--suppliers, consumers, investors.

Over the past few decades, the petroleum industry in the United States has undergone some fundamental changes in its operations. These changes range from declines in domestic oil production, and in crude and product inventory levels, to emerging new technologies; from new environmental requirements that affect the costs of its operations, to new financial markets that affect the prices of its products. When such changes evolve gradually, they can be absorbed smoothly in the markets. But when changes in supply and demand occur suddenly or unexpectedly, they can lead to sharp market reactions. The resulting rapid price changes are symptoms of these reactions — evidence of a market imbalance, and the signal that a market correction is underway.

Outline of the Report

The first chapter of the report presents, in summary terms, a broad **overview** of trends in petroleum markets. The other seven chapters present, in greater depth, analyses of key issues and the underlying trends that influence petroleum markets today and in the future.

- Chapter 1, "Industry Overview," reviews the broad trends in supply and demand of petroleum. It highlights recent events and summarizes their effects on the markets.

- Chapter 2, "Spring '96 Gasoline Price Runup: An Example of Petroleum Market Dynamics," recaps the factors that led to last year's jump in motor gasoline prices, and tracks the resumption of more stable market conditions since then. This chapter serves as a case study in dynamics of wholesale and retail product markets and

[*] U.S. Department of Energy, *An Analysis of Gasoline Markets Spring 1996*, DOE/PO-0046 (June 1996).

[**] U.S. Department of Energy, "Secretary Federico Peña's Greetings to DOE Employees," DOECAST (3/14/97).

the interaction with other sectors of the petroleum industry and their related markets.

- Chapter 3, "Oil Supply: U.S. Perspective on a Global Market," identifies factors that have contributed to historical volatility in world oil prices. It examines declining domestic oil production and rising global production over the past decade. Future shifts in the sources of world oil supply, based on current reserves, are projected. It addresses resource potential, development costs, and technological advancements in the U.S. and overseas.

- Chapter 4, "Crude Oil Imports: Growing U.S. Dependence," describes the conditions that have driven the steep rise in U.S. oil imports over the past decade, and addresses issues related to increasing reliance on foreign suppliers. It covers regional shifts in domestic demand and foreign supply, patterns in the quality of imported crude oil, and the economic, logistical, and political implications of these changes.

- Chapter 5, "Petroleum Stocks: Causes and Effects of Lower Inventories," reviews EIA's survey data on stocks to determine the underlying trends in the recent decline in inventory levels. Forces that influence petroleum inventory levels, such as current and expected prices and refinery margins, are assessed.

- Chapter 6, "Petroleum Futures Markets: Volatile Prices, Controversial Functions, Stagnant Volumes," discusses the evolution of futures markets in crude oil and petroleum products over the past two decades. It describes how they are used by petroleum industry participants to hedge their price risk, and by the noncommercial traders that provide liquidity for the hedgers. It addresses several controversial issues related to futures markets.

- Chapter 7, "U.S. Refining Cash Margin Trends: Factors Affecting the Margin Component of Price," investigates margin behavior over the past decade to identify the factors that influence margin fluctuations. In particular, it examines the effects on margins of refinery configuration and location, crude oil quality, and environmental regulations.

- Chapter 8, "Financial Performance: Low Profitability in U.S. Refining and Marketing," draws upon data from EIA's Financial Reporting System to explore profitability in domestic refining and marketing operations of the major oil companies. It concludes that their profitability over the past 10 years has been volatile and frequently lower than U.S. industry in general.

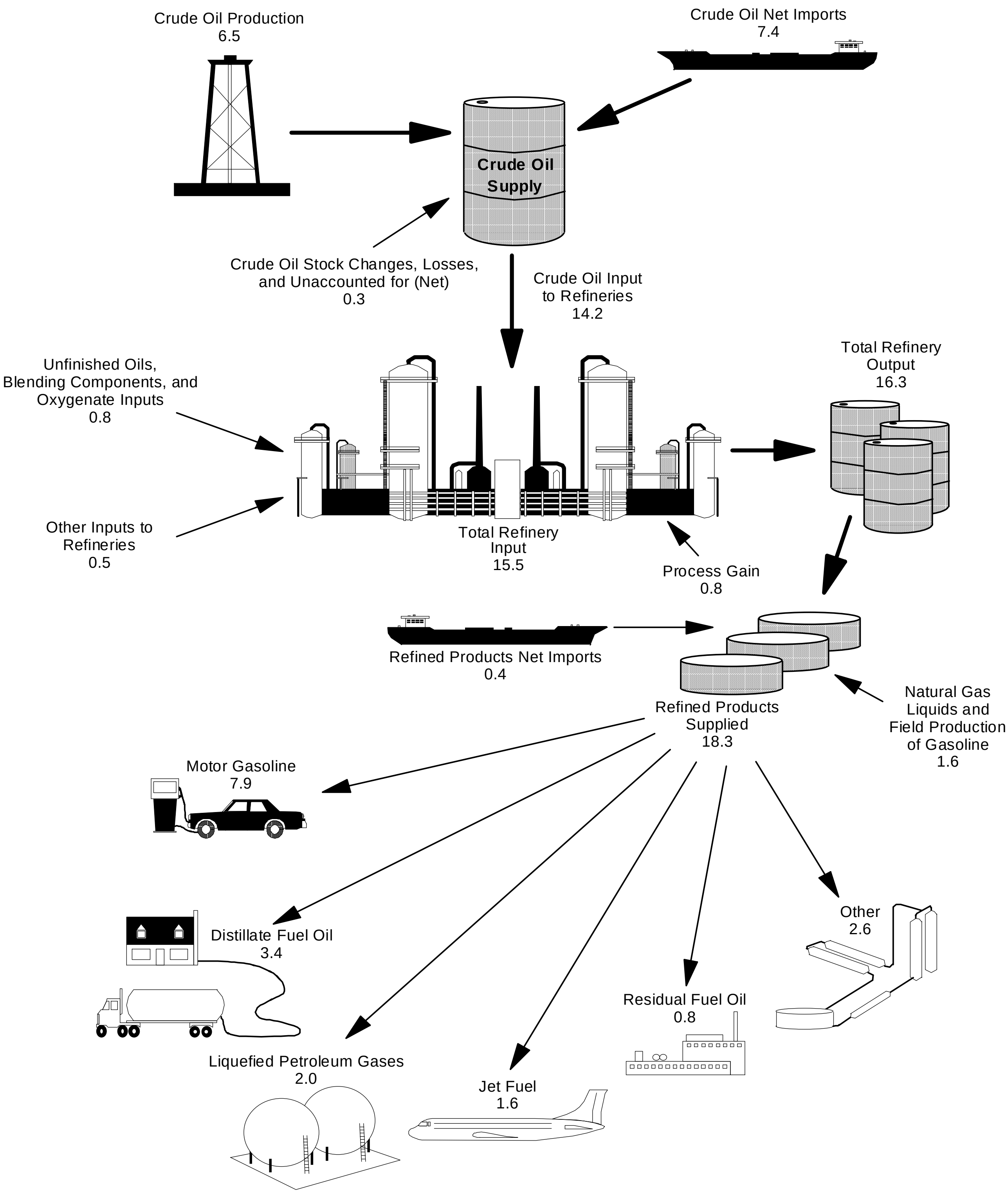
1. Industry Overview

This section provides an overview of the petroleum industry, summarizing recent trends in some of the major petroleum markets and major industry sectors. Each summary focuses on 1996, but puts the year in historical perspective. The areas reviewed are:

- Overview of the Petroleum Sector
- World Crude Oil Markets
- World Petroleum Supply and Demand
- U.S. Petroleum Supply
- U.S. Petroleum Net Imports
- U.S. Petroleum Demand
- U.S. Refining
- U.S. Gasoline Markets
- U.S. Distillate Markets
- Clean and Alternative Transportation Fuels
- Petroleum Futures Markets
- Financial Performance

The remaining sections of the report examine, in greater depth, issues relating to the major petroleum markets and major industry sectors.

Figure 1. U.S. Petroleum Flow, 1996
(Million Barrels per Day)



Source: Energy Information Administration, Petroleum Supply Annual, DOE/EIA-0340 (June 1997), Table 3.

Overview of the Petroleum Sector

This overview highlights recent events and trends in major petroleum markets and segments of the petroleum industry, including:

- **The United States Uses More Energy from Petroleum than from Any Other Energy Source.** Petroleum supplies over 50 percent more energy than natural gas, close to twice the energy of coal and 2.5 times the energy coming from all other energy resources. The United States is also one of the largest petroleum producers in the world, but consumes more than it produces, requiring net imports of both crude oil and products to meet demand.

- **Petroleum Markets and the Industry That Serves Them Are Complex.** The oil business is very capital-intensive, is international in scope, and requires a complex transportation and storage infrastructure to operate. Crude oil resources are found worldwide, with many crude-producing regions (e.g., the Middle East) being some distance away from large consuming areas like the United States, Europe and Asia. Crude oil is shipped to refineries worldwide using tankers and pipelines. Generally refineries are located near large consuming areas, but substantial international movements of refined petroleum products also occur as supply/demand balances and market opportunities change.

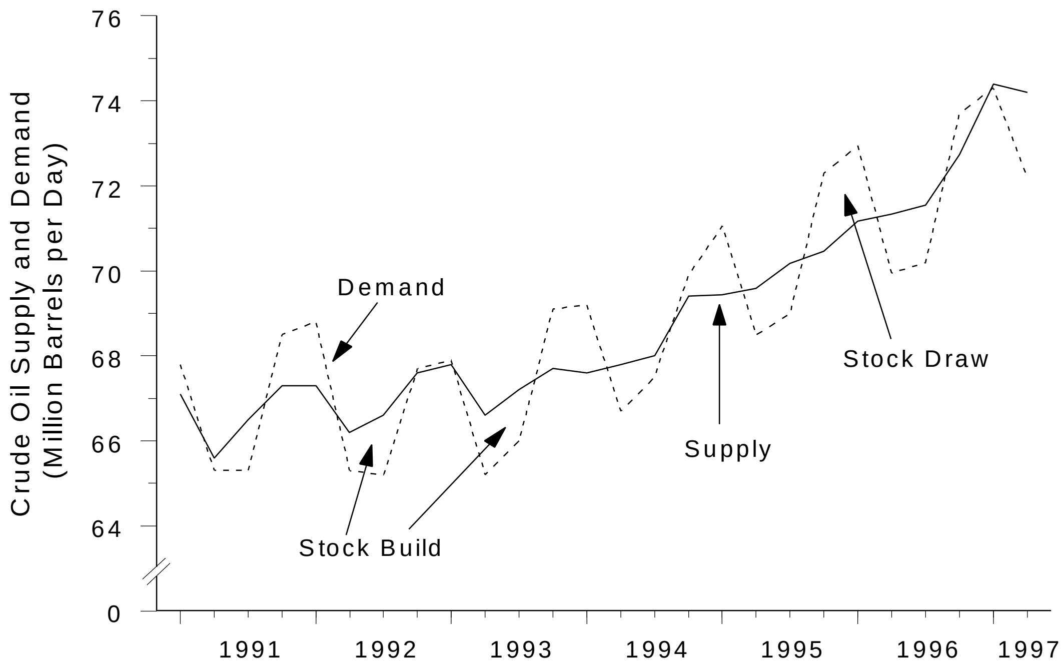
- **Crude Oils Are Heterogeneous.** Crude oils differ as to the relative quantities of light and heavy hydrocarbons and content of other materials, such as heavy metals and sulfur. Each barrel of crude oil is processed in refineries to produce a wide range of hydrocarbon products, including gasoline, heating oil, diesel fuel, residual fuel, coke, lubricants, asphalt, and waxes, as well as non-hydrocarbon products such as sulfur and vanadium. Different crude oils can be used to produce different amounts of these products depending on their original composition and the type of equipment used by the refinery to process the crude oils. Crude oils with higher percentages of light hydrocarbons are more valuable than those with a lower light hydrocarbon content because they yield larger percentages of high-valued products such as gasoline with less processing equipment investment.

- **Changing Regulations and Economics Have Affected the Domestic Refinery Business.** Since the early 1980's, the number of U.S. refineries has fallen by almost 50 percent, but the remaining refineries have improved their efficiencies and flexibility to process heavier crude oils by incorporating improved technology and by adding upgrading units downstream of the distillation units. In the 1990's, investments were driven mainly by new clean fuel requirements and the need to improve on the environmental impacts of operations.

- **The Many Products Coming from the Refineries Travel Down Complex Distribution Systems to Very Different End-Use Markets.** Products leave refineries by different routes to reach their end-use customers. Each end-use market has its own supply, demand and price factors. Products such as residual fuel oil are subject to direct competition from alternative fuels like natural gas, while in other cases, such as gasoline, no viable short-term alternatives exist. Gasoline consumption varies with factors such as vehicle efficiency, miles driven and the number of vehicles using this fuel, rather than by consumers' ability to switch fuels. Long-term factors, such as the evolution of alternative fuels and the use of more efficient vehicles, can affect the gasoline market.

Figure 2. 1996 Crude Oil Prices Rise Due To Tight Supply/Demand Balance

Increasing World Demand Tightens Crude Oil Markets

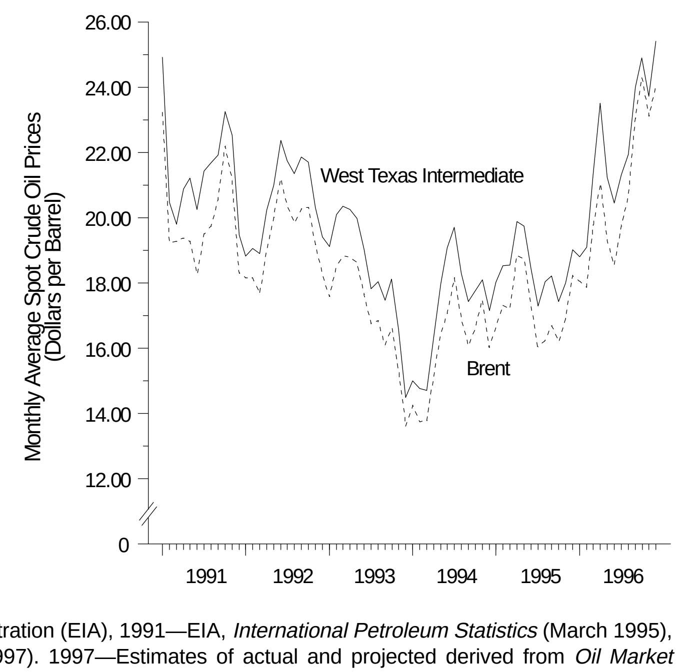


Supply Demand Balance in 1996 Keeps Pressure on Crude Oil Prices

World Petroleum Supply and Demand Balance
(Million Barrels Per Day)

Year	Supply	Demand	Stock Change
1991	66.6	66.7	-0.1
1992	66.9	66.7	+0.2
1993	67.3	67.0	+0.3
1994	68.2	68.3	-0.1
1995	69.9	70.2	-0.3
1996	71.7	71.7	-0

Even Iraqi Sales in December 1996 Have Little Effect on Prices



Sources: **World Supply and Demand:** Energy Information Administration (EIA), 1991—EIA, *International Petroleum Statistics* (March 1995), Table 2.1. 1992-1996—EIA, *International Petroleum Statistics* (May 1997). 1997—Estimates of actual and projected derived from *Oil Market Intelligence*, publisher Edward L. Morse, New York, NY, p. 1 (June 2, 1997). **World Petroleum Supply and Demand Balance:** EIA, 1991—*International Petroleum Statistics* (March 1995), Table 2.1. 1992-1996—*International Petroleum Statistics* (May 1997). **Spot Crude Oil:** Standard and Poor's Platts.

World Crude Oil Markets

Following the Gulf War in 1991, world petroleum supply increased, while demand languished through a recession, and crude oil prices weakened. As the recession ended, demand began growing again, and the petroleum supply/demand balance tightened, bringing prices up. As 1996 began, the world supply demand balance had tightened further, setting the stage for the price increases that occurred during the year.

- **Increasing World Demand Tightens Crude Oil Markets.** Prices increase when the balance between supply and demand is tight. A tight balance develops when demand exceeds supply, and stocks are pulled down. Stock levels serve as an indicator of tightness, representing immediate short-term supply. When they are low, and demand is increasing, buyers tend to bid more aggressively to assure supply. In 1992 and 1993, supply exceeded demand, petroleum stocks were building, and prices were on a downward trend. That situation began to reverse in 1994 as the world economy improved and demand growth increased. In 1994 and 1995 demand exceeded supply and stocks were drawn down. As 1996 began, demand was high and continued to exceed production. The stock draw in the first quarter was a very strong 1.8 million barrels per day, setting the stage for price increases.

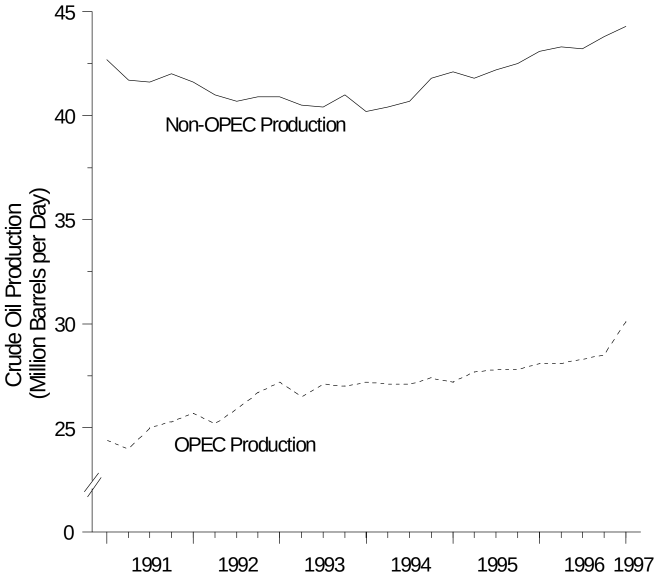
- **Supply/Demand Balance in 1996 Keeps Pressure on Crude Oil Prices.** The winter of 1995-96 was cold, which pushed distillate demand up and pulled inventories down as demand surged ahead of production. Thus, 1996 began with oil inventories already depleted. As the cold weather continued, crude prices rose in March and peaked in April when a late cold snap drove refiners to the market to meet the distillate demand surge when they would normally be preparing for the gasoline season. Strong petroleum demand growth continued through the 2nd and 3rd quarters. World petroleum stocks normally build in these quarters. Although the 1996 stock build was normal, it was not large enough to offset the effects of the previous winter's drawdown, so world petroleum stocks remained low at the end of summer. As preparation for the 1996-97 heating season began, the low state of distillate stocks both in Europe and the U.S. brought buying pressure to the world crude market, and prices began to rise well before the heating season got underway. In late October, markets questioned whether the concerns about distillate were exaggerated, and the price fell back briefly. Then, cold weather in Europe caused the market to end the year on a high note. Crude oil prices increased approximately $6 per barrel over the course of 1996.

- **Expectations and Backwardation Discourage Stock Building.** Throughout 1996, with new supply on the horizon, analysts expected the tight oil markets to loosen. In believing that a supply surplus would develop, these analysts anticipated a weakening in crude oil prices. Given this expectation with current tight markets, the futures markets exhibited fairly strong backwardation throughout the year. "Backwardation" occurs when the price of crude oil for future delivery is less than the prompt (current) price. Backwardation can be expected to occur when prompt prices are bid up relative to future prices, reflecting expectations that prices will subsequently fall off. In 1996, the outlook for a supply surplus, coupled with tight prompt markets, kept crude oil prices virtually always in fairly deep backwardation, and the persistent expectation that prices would fall provided a disincentive to stock building. Buyers did not want to fill their storage with crude oil that was expected to be several dollars cheaper within a month or two.

- **Iraqi Sales in December 1996 Have Little Immediate Effect on Prices.** One of the anticipated supply increases in 1996 was the return of Iraq to the market as a result of U.N. negotiations. When Iraqi sales finally began in December 1996, the West Texas Intermediate (WTI) price fell about $2.50 per barrel, but within about a week's time, the price came back to the level before sales began and pushed to new heights. In the strong world demand period of the fourth quarter, the Iraqi volumes of about 500 thousand barrels per day were readily absorbed by the market. In the medium term, however, the Iraqi volumes, in combination with growing non-OPEC production, could be a factor in creating surplus supply, eroding market supply/demand tightness and bringing down prices.

Figure 3. World Oil Supply Grows Lighter, but Falls Behind Demand

Both OPEC and Non-OPEC Sources Increase Production

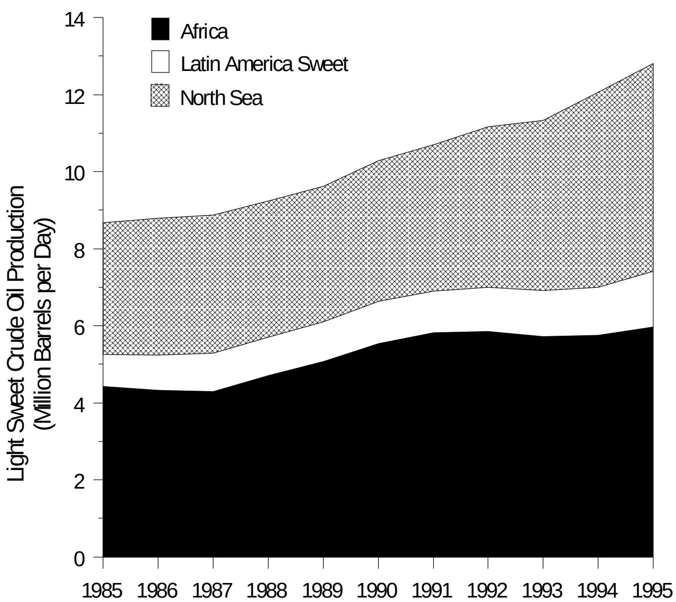


1996 Supply-Demand Balance Keeps Market Tight

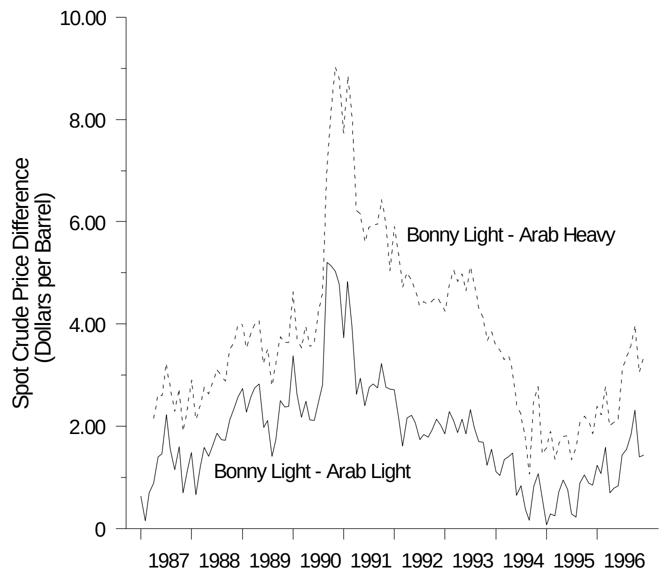
Actual and Predicted World Petroleum Supply and Demand

		1995 Actual	1996 Actual	Increase
Demand	OECD	40.5	41.2	+0.7
	Non-OECD	29.7	30.5	+0.8
	Total	70.2	71.7	+1.5
Supply	OECD	19.2	19.7	+0.5
	Other Non-OPEC	23.1	23.7	+0.6
	OPEC	27.6	28.3	+0.7
	Total	69.9	71.7	+1.8
Stock Change		-0.3	0	N/A

Production of Atlantic Basin Light-Sweet Crude Oil Increases



Light-Heavy Crude Oil Price Differentials Fell in 1991-1994, But Began to Recover in 1995



Sources: **OPEC and Non-OPEC Production:** Energy Information Administration (EIA), 1991-1996—EIA, *International Petroleum Statistics* (various issues), Table 2.1. Estimate of First Quarter 1997 Actual—*Oil Market Intelligence Update* (New York, NY) (June 2, 1997), p. 1. **Actual and Predicted World Petroleum Supply and Demand:** EIA, Actual—*International Petroleum Statistics* (May 1997), Table 2.1. Predicted—International Energy Agency (December 1995) and *Oil and Gas Journal* (January 29, 1996), p. 68. **Light Sweet Crude Oil:** EIA, derived from Form EIA-814 data. **Spot Crude Price Differences:** Standard and Poor's Platts.

World Petroleum Supply and Demand

World demand and supply have both been growing since 1994, but demand has grown more strongly than supply, keeping the world supply/demand balance tight. Both OPEC and non-OPEC production rose to help meet this growing demand, with particularly strong growth coming from the non-OPEC light sweet crude oil producing regions of the Atlantic Basin. This increase in light sweet crude oils served to depress the light heavy crude price differences that affect refinery economics worldwide.

- **World Demand Growth Continues to Be Strong.** Initial estimates indicate world petroleum demand grew 2.2 percent in 1996, which was lower than the 2.8 percent growth experienced in 1995, but still strong. U.S. demand, which represents over 25 percent of the world total, increased 2.9 percent, but Western Europe only rose by 1.3 percent. OECD countries in total grew 1.6 percent in 1996 as their economies continued to expand. Non-OECD countries, however, experienced a 2.9 percent increase in 1996 as their economies flourished and as developing countries continued to evolve and use more energy. Non-OECD countries now account for 43 percent of world demand.

- **Both OPEC and Non-OPEC Sources Increase Production.** OPEC production increased by about 700 thousand barrels per day in 1996. The largest part of the increase came from Venezuela, where production rose about 330 thousand barrels per day, followed by Nigeria, where it rose about 180 thousand barrels per day. Many of the OPEC member countries are producing above their OPEC-established quotas, which have not been changed for several years. Growing world oil demand and increasing crude prices have allowed OPEC to avoid confronting the difficult task of changing quotas. Production from non-OPEC countries increased about 1,150 thousand barrels per day, with the largest increases coming from the North Sea (up from about 400 thousand barrels per day) and Latin America (Mexico, up 250 thousand barrels per day and Brazil, up 100 thousand barrels per day).

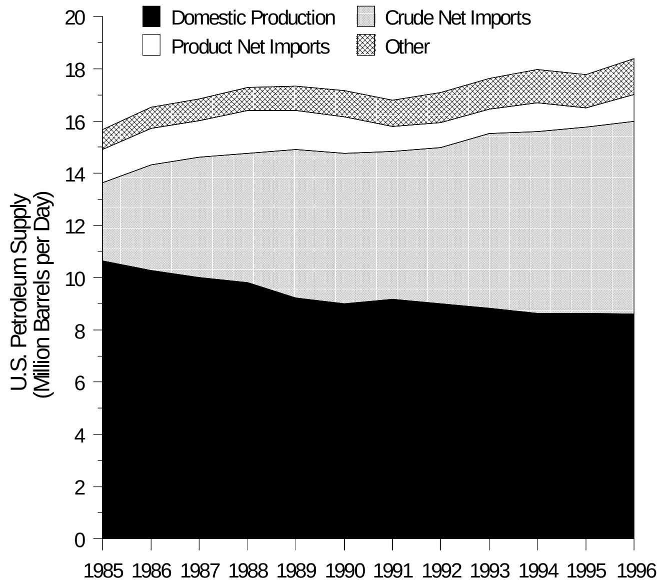
- **1996 Supply-Demand Balance Keeps Market Tight.** Demand in 1996 was slightly below forecasted levels. Non-OPEC supply, however, fell well below expectations. It was expected to increase 1.9 million barrels per day, but only increased 1.1 million barrels per day. The North Sea alone fell short of predictions by over 300 thousand barrels per day. Non-OPEC and OPEC production together just met demand for the year, keeping crude oil markets tight.

- **Atlantic Basin Production of Light Sweet Crude Increases at a Faster Rate than World Production.** The rate of growth of light sweet crude oil production in the Atlantic Basin since 1985 greatly exceeded world crude production growth. Growth in crude oil production since 1985 came largely from the Atlantic Basin, and much of this new production was light sweet crude. From 1985 to 1995, world crude production increased by 16 percent. At the same time, crude production from sweet crude producing areas of the Atlantic Basin (North Sea, Africa, Colombia, and Argentina) increased by 48 percent. The area with the greatest volume increase was the North Sea, where production increases are expected to continue for a few years. Africa also showed large increases, with Nigeria and Angola together adding over 900 thousand barrels per day to the market from 1985-1995. Sweet crude oil production also increased in Latin America, and greater increases are coming in the next few years as Colombia attains full production of Cusiana. The strong growth in Atlantic Basin light sweet crude production had significant impacts on the relative market value of crudes in the region and on other world markets.

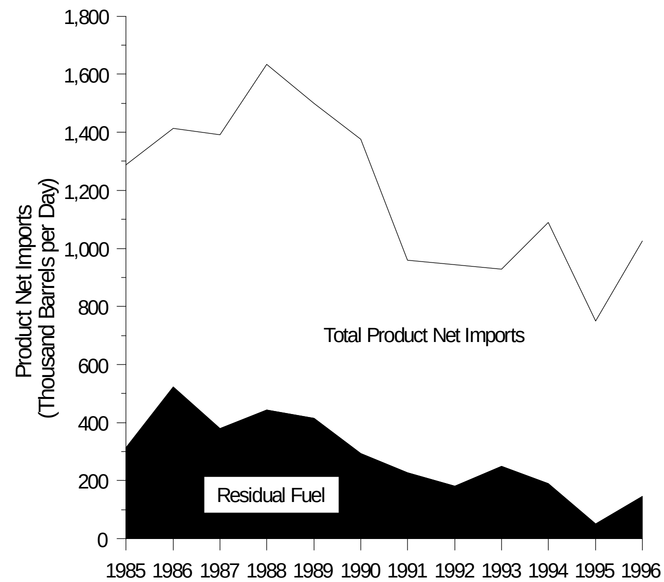
- **Recovery of Light-Heavy Crude Price Differential Continues.** Increased availability of light sweet crude in the Atlantic Basin drove light-heavy crude oil and product price differences down. From 1990 to 1994, the price differential between light and heavy crude narrowed because of the increased availability of light crude oil in the region. The light-heavy difference has a major impact on refining margins, as discussed in Chapter 7. Beginning in 1995, the price difference widened slightly due to a sharp increase in light crude oil shipments from Africa to Asia. The differential had declined to the point that, in spite of the long haul, African crudes became attractive to meet Asia's growing light product needs. The Asian market effectively sets the floor price for the light African crude oils, which in turn provides a price floor for the other Atlantic Basin light crude oils. Production increases in Atlantic Basin light sweet crude oils should continue for the next few years, keeping downward pressure on the light-heavy price differential.

Figure 4. U.S. Increases Dependence on Crude Oil Imports

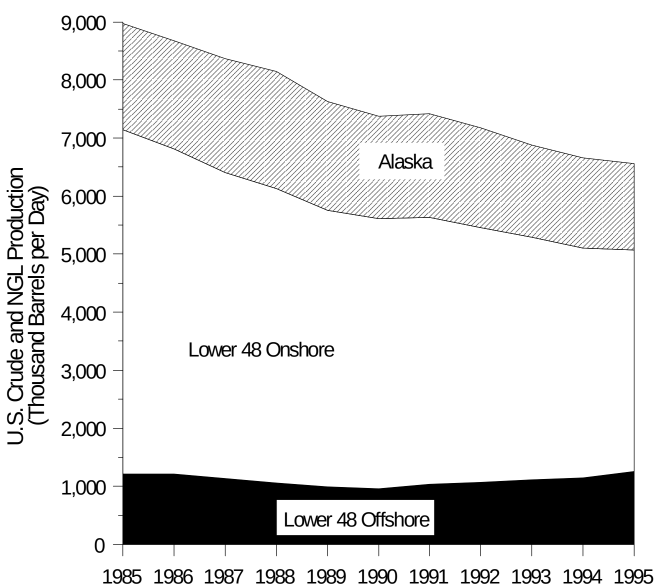
The U.S. Is Growing More Dependent on Imported Crude Oil



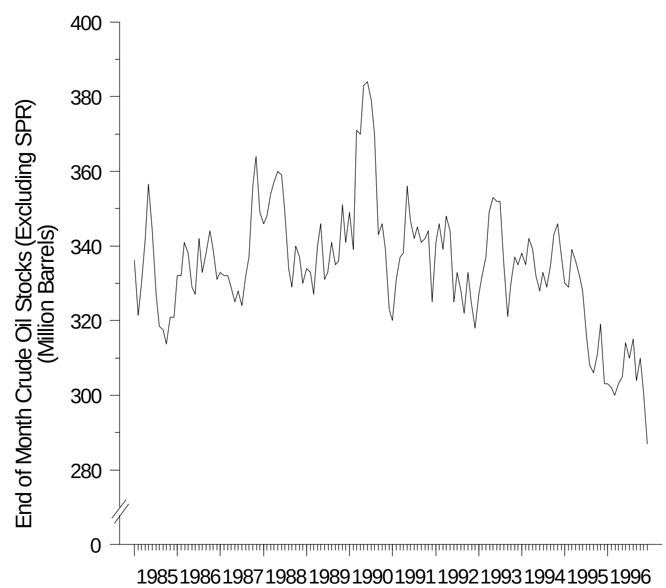
Residual Fuel Leads Product Import Decline



New Offshore Sources Are Slowing Domestic Production Decline



U.S. Crude Oil Stocks Are Down Again in 1996



Sources: Energy Information Administration (EIA). **Petroleum Supply:** 1985-1995—*Petroleum Supply Annual* (Vol. 1), Table S1. 1996—*Petroleum Supply Monthly* (February 1997), Tables 26 and 49. **Net Imports:** 1985-1995—*Petroleum Supply Annual* (Vol 1), Table 29. 1996—*Petroleum Supply Monthly* (February 1997), Table 49. **Crude Oil and NGL Production:** 1985-1995—*Petroleum Supply Monthly*, Table 26. 1996— *Petroleum Supply Annual* (Vol. 1), Table 14. **Crude Oil Stocks:** 1985-1995—*Petroleum Supply Annual* (Vol. 1), Table S2. 1996—*Petroleum Supply Monthly*, Table 2.

U.S. Petroleum Supply

Growing U.S. petroleum product demand and declining domestic crude oil production have combined to make the United States increasingly dependent on crude oil imports. Although total net petroleum imports (imports minus exports) have been increasing, net product imports have decreased. Domestic production of crude oil is declining in virtually all U.S. production areas with the exception of the Gulf of Mexico, where there is much current activity — especially in the deep water areas. During 1996, while imports continued to increase, crude oil inventories declined, partially due to the tight crude market that produced high crude oil prices.

- **The U.S. Is Growing More Dependent On Imported Crude Oil.** Decreasing domestic crude oil production combined with rising demand are causing the United States to become more dependent on imports of crude oil and refined products. Since the crude oil price collapse in 1986, domestic production has declined as high-cost wells were closed. In 1985, net imports of crude oil and products were 4.3 million barrels per day and provided 27 percent of oil product supply. By 1996, net imports of crude and products had nearly doubled to 8.4 million barrels per day and represented 46 percent of U.S. supply. Other domestic sources rose slightly, primarily as the result of growth in the use of oxygenates in gasoline.

- **Residual Fuel Leads Product Import Decline.** The large increase in oil imports has been in the form of crude oil rather than products. Net product imports have declined both on a percentage and a volume basis. From 1985 to 1990, product imports averaged 1,434 thousand barrels per day, but from 1991 to 1996 the average dropped 484 thousand barrels per day to 950 thousand barrels per day. At the same time, product imports' average share of total imports fell from 24 percent to 13 percent. A large part of the decline in product imports came from the drop in net imports of residual fuel, which fell 220 thousand barrels per day as demand for residual fuel diminished. Another important part of the net import decline derived from an increase in exports of distillate fuel oil and petroleum coke.

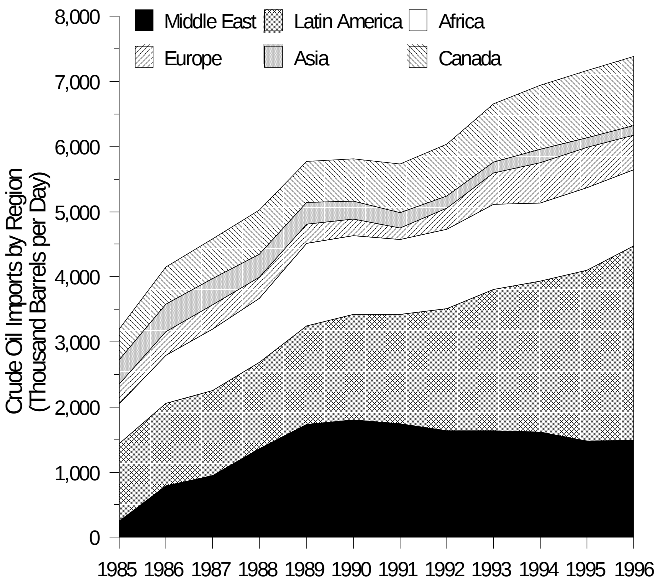
- **New Offshore Sources Are Slowing the Domestic Production Decline.** From 1985 to 1995, U.S. production of crude oil and natural gas liquids fell from approximately 9 million barrels per day to 6.6 million barrels per day. Production in the onshore lower 48 states declined steadily over the entire period, while Alaskan production rose between 1985 to 1988, but declined since then. In recent years the most promising U.S. production area has been the Gulf of Mexico, the source of most of the lower 48 offshore production. Crude oil production in the Gulf increased about 300 thousand barrels per day from 1990 to 1995, which helped to slow the overall production decline rate in the U.S. A large number of oil projects are under development in the Gulf of Mexico, many of which are large projects in deep water. A joint *Petroleum Economist* and IEA estimate[1] projects Gulf of Mexico oil production to increase by 1 million barrels per day between 1995 and 2000. Overall U.S. production will still decline at about 2 perecent per year.

- **U.S. Crude Oil Stocks Are Down Again in 1996.** Inventories or "stocks" of crude oil are maintained to provide working volumes in the system and to provide a buffer against demand and price changes. A number of factors can affect stock levels, including price expectations, demand surges, supply problems, and even how the crude oil is delivered to refiners. Pipeline delivery of domestic crude oil requires the least storage, but much more tankage is required to accommodate the infrequent deliveries of large batches of crude by very large, long-haul tankers. Increased reliance on short haul crude oils can produce a reduction in stock levels simply due to the use of smaller tankers. Crude oil stocks are also affected by variations in the tightness or looseness of the crude markets, both seasonally and for longer periods as discussed in Chapters 2 (Spring '96 Gasoline Price Runup) and 5 (Stocks). From 1984 to 1995, crude oil stocks fluctuated around 320-360 million barrels, but fell considerably in 1995 and again in 1996. While it looked like stocks might be leveling off during the second and third quarters of 1996, they plunged again during the fourth quarter to end the year at a record December low of 285 million barrels. In addition to crude oil, many other petroleum product stocks were lower than normal. During the fourth quarter 1996, refiners increased their runs to meet distillate needs, pulling down crude oil stocks in the process. In general, the low stocks in 1996 cannot be explained by any one of the factors affecting stocks mentioned above, but the refiners' reluctance to build stocks was at least partially due to current and expected prices. Prompt (current) crude oil prices remained strong, but future prices were expected to decline.

[1]"Shell Leads Rush to Deeper Waters," *Petroleum Economist* (January 1997), pp. 5-10.

Figure 5. Petroleum Import Levels and Sources Change

Crude Oil Imports From Atlantic Basin Are Increasing

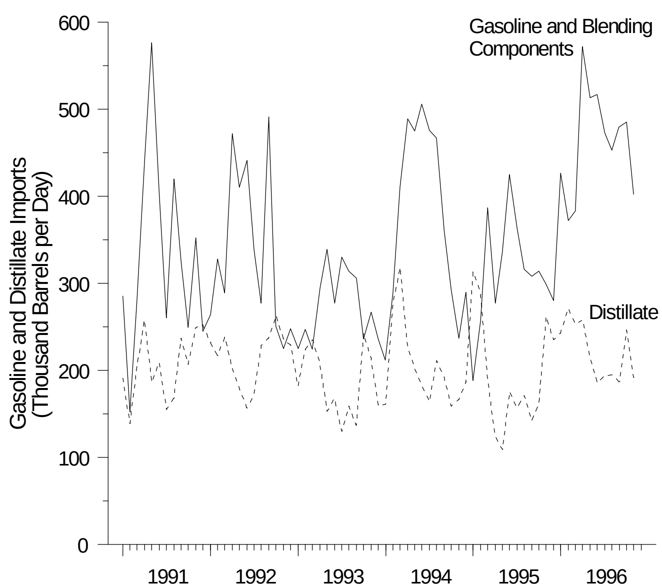


Quality of Crude Imports Has Not Changed Much

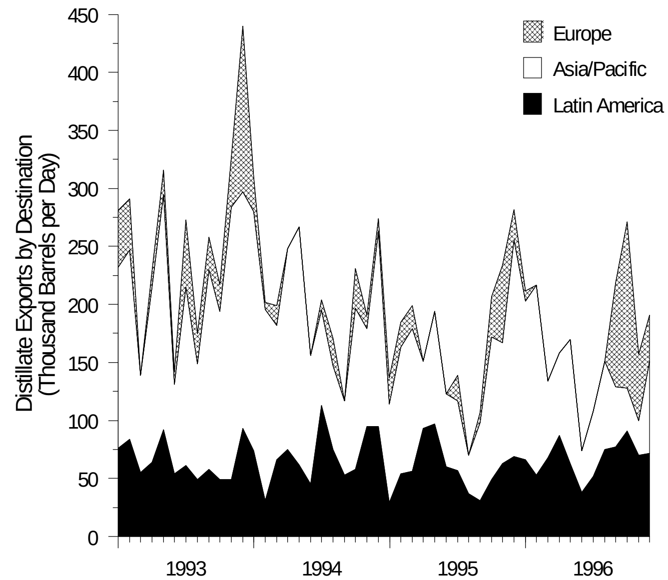
Sulfur Content and Gravity of Imported Crude Oil

Sulfur	Gravity	1990 MB/D	1990 Percent	1995 MB/D	1995 Percent
<=0.5 %S	>36 API	1,041	16.7	1,341	17.6
<=0.5 %S	30-36 API	804	12.9	1,016	13.4
<=0.5 %S	<30 API	535	8.6	639	8.4
>0.5<=2.0 %S	>36 API	547	8.8	469	6.2
>0.5<=2.0 %S	30-36 API	839	13.5	1,057	13.9
>0.5<=2.0 %S	<30 API	474	7.6	730	9.6
>2.0 %S	>36 API	5	0.1	16	0.2
>2.0 %S	30-36 API	726	11.7	776	10.2
>2.0 %S	<30 API	1,253	20.1	1,557	20.5

Product Imports Help to Meet Seasonal Demand Swings



Market Opportunities Drive Changes in Distillate Export Patterns



Sources: Energy Information Administration (EIA). **Crude Oil Imports:** 1985-1995—*Petroleum Supply Annual* (Vol. 1), Table 21. 1996—*Petroleum Supply Monthly* (February 1997), Table S3. **Sulfur Content and Gravity of Imported Crude Oil:** EIA, *Petroleum Supply Annual* (Vol. 1), Table 16. **Gasoline and Distillate Imports:** 1991-1995—*Petroleum Supply Annual* (Vol 1), Table 21. 1996—*Petroleum Supply Monthly* (various issues), Table 35. **Distillate Exports:** EIA, 1993-1995—*Petroleum Supply Annual* (Vol. 1), Table 28. 1996—*Petroleum Supply Monthly*, Table 47.

U.S. Petroleum Imports

From the late 1980's into the 1990's, supply sources of U.S. crude oil imports shifted from the Middle East towards Latin America. While light sweet crude oil availability increased dramatically in the Atlantic Basin, U.S. light sweet crude imports did not increase proportionally. Gasoline product imports increased from marginal sources, such as Europe and the Middle East, when the United States market presented price opportunities. Conversely, export opportunities for distillate grew during the 1990's as world markets changed.

- **Crude Oil Imports from the Atlantic Basin Are Increasing.** From 1985 to 1990, total crude imports increased from 3.2 million barrels per day to 5.9 million barrels per day. Saudi Arabia accounted for nearly 60 percent of the additional imports. Since 1990, the supply sources for U.S. crude imports have shifted toward Latin America. Imports from Mexico, Venezuela, and other Latin American countries nearly doubled from 1990 to 1996, rising from 1.6 million barrels per day to nearly 3.0 million barrels per day. This increase can, in large measure, be attributed to the competitive advantage of short-haul crudes, and to the downstream integration of Venezuela and Mexico into the U.S. refining business. The Venezuelan state oil company (PDVSA) acquired and expanded CITGO, which now has 650 thousand barrels per day of U.S. refining capacity. The Venezuelans also acquired a stake in the 265 thousand barrels per day Lyondell refinery. After making these acquisitions, PDVSA invested in process upgrading to handle the Venezuelan crude oils, many of which are heavy. The Mexican state oil company (PEMEX) has acquired a share of the Shell Deer Park refinery with a capacity of 215 thousand barrels per day, which also was upgraded to run heavy-sour Mexican crude oils.

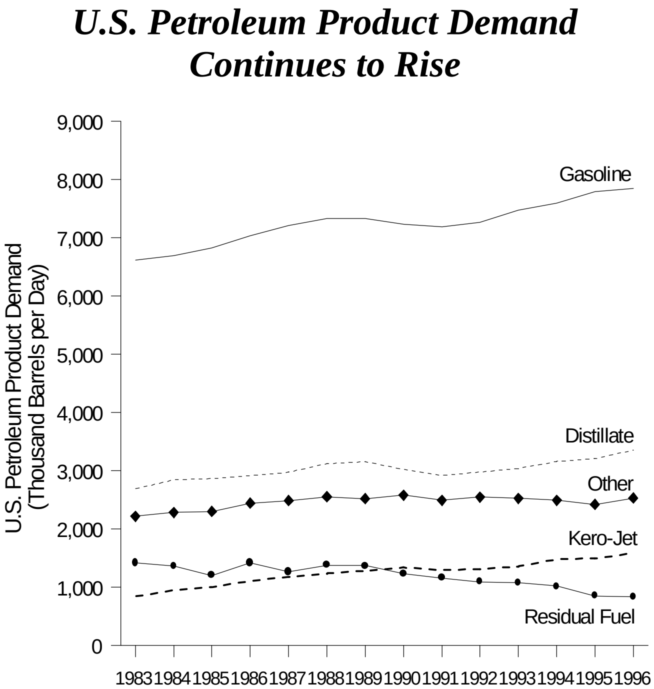
- **Quality of Crude Imports Has Not Changed Much.** From 1985 to 1990, imports of light sweet crude oil increased as a percent of total. But from 1990 to 1995, the shares of crude imports by quality attribute have not changed much. Despite increased availability of light sweet crude oils in the Atlantic Basin, and a decline in the price difference between light and heavy crude oils, the U.S. light sweet crude oil imports have only risen in proportion with the total imports. As discussed in Chapter 7 (Refinery Margins), once refiners have invested in heavy-sour crude processing facilities, it takes a large drop in the light-heavy price difference to cause refiners to switch back to the light sweet crude oils.

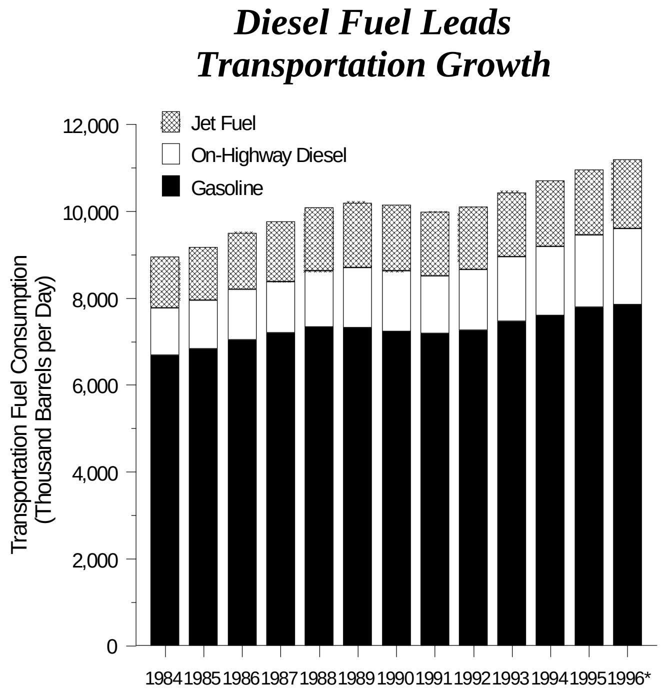
- **Gasoline Imports Rise in 1996 with Europe Picking Up a Large Piece of the Growth.** The need for gasoline imports varies significantly from year to year. In 1996 gasoline imports and blending components averaged 469 thousand barrels per day compared to 313 thousand barrels per day in 1995. Over 50 percent of the gasoline imported into the United States comes from three areas: Canada, the Virgin Islands, and Venezuela. These provide a fairly steady source of gasoline imports, averaging 200-280 thousand barrels per day annually. If gasoline prices are attractive in the United States relative to Europe, gasoline volumes flow across the Atlantic, and total imports for a given month can reach 400-500 thousand barrels per day. The strong prices in the United States in April 1996 drew gasoline and blending component imports of 573 thousand barrels per day. Europe supplied 139 thousand barrels per day for the year, compared to 68 thousand barrels per day in 1995. The increase in European imports represented 46 percent of the total increase for 1996.

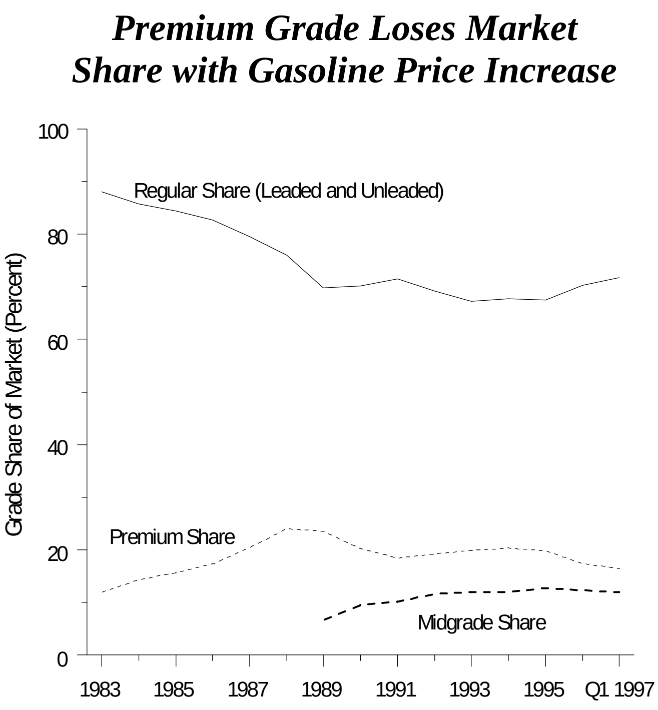
- **Three Countries Are Major Suppliers of Distillate Imports.** Over 90 percent of U.S. distillate imports come from three areas: the Virgin Islands, Canada and Venezuela. For the past several years, distillate imports averaged about 200 thousand barrels per day, with each of the three areas providing about 30 percent of the total.

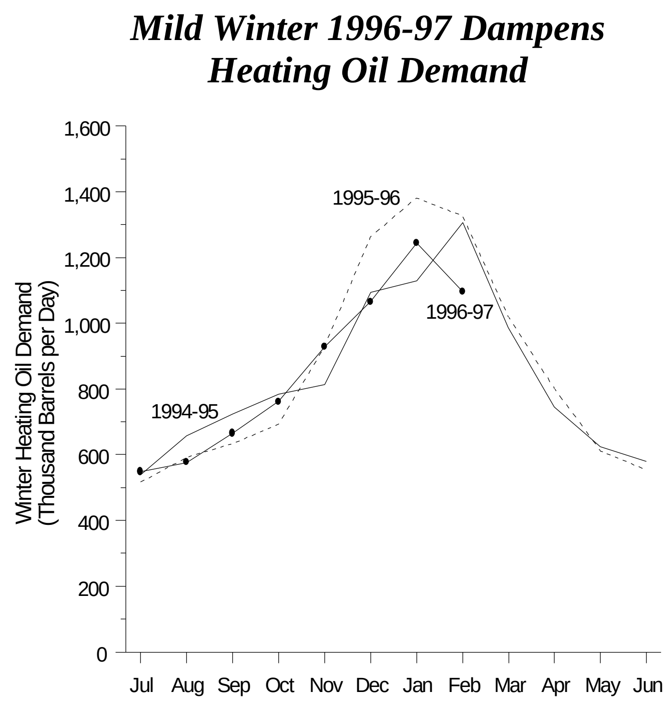
- **Market Opportunities Drive Changes in Distillate Export Patterns.** While sources of distillate imports have not changed much, distillate exports varied by both volume and country of destination, based on market opportunities. Some distillate exports flowed to regional Latin American markets on a steady basis, but exports to the Asia/Pacific region and to Europe rose and fell dramatically. In the early 1990's, the Asian market for distillate was tight, and U.S. production was a marginal source of Asian supply. Then, exports to Asian markets fell as Asian refining capacity expanded. During the second half of 1996, high distillate prices in Europe drew strong export volumes from the United States. For the months of September, October and November, distillate exports to Europe averaged about 100 thousand barrels per day, increasing from just 42 thousand barrels per day for the same months in 1995. The strong distillate export volumes in the fall of 1996 occurred when U.S. inventories were low and U.S. prices were high, but not as attractive as European prices.

Figure 6. Light Transportation Fuels Drive U.S. Demand Growth









Note: In bottom left graph leaded gasoline is included under regular grade gasoline.

Sources: **Petroleum Product Demand:** Energy Information Administration (EIA), 1983-1995—*Petroleum Supply Annual* (Vol. 1), Tables S1, S4, S5, S6, and S7. 1996—*Petroleum Supply Monthly* (February 1997), Tables S1, S4, S5, S6, and S7. **Other:** *Petroleum Supply Monthly* Tables S4 and S7. **Transportation Fuels:** EIA, *Fuel Oil and Kerosene Sales*. **Gasoline by Grade:** EIA, 1983-1994—*Petroleum Supply Annual* (Vol. 1), Table 7. 1995-1996—*Petroleum Supply Monthly*, Table 7. **Winter Heating Fuel Demand:** EIA, 1994—*Petroleum Marketing Annual* (Vol. 1), Table 50. 1995-1997—*Petroleum Marketing Monthly*, Table 50.

U.S. Petroleum Demand

U.S. demand for petroleum continued to climb in 1996, reaching an annual average of 18.2 million barrels per day. The growth comes from the transportation sector, which has little economic alternative to petroleum-based fuel. Transportation growth was countered somewhat by continuing declines in use of residual fuel.

- **U.S. Petroleum Product Demand Continues to Rise.** In 1996, U.S. demand for petroleum products rose 2.9 percent, with the transportation sector continuing to provide primary support to overall long-term growth. While higher product prices had a noticeable impact on gasoline demand, which increased just 0.8 percent in 1996, a strong economy helped buoy kerosene jet fuel and on-highway diesel demand, up 5.1 percent and 5.5 percent, respectively. Another long-run trend that persisted in 1996 was the further weakening of residual fuel demand, down 1.3 percent in 1996, as cheaper, alternative energy sources continue to erode residual fuel's market share.[2]

- **Diesel Fuel Leads Transportation Growth.** In 1984, light transportation fuels held a 63 percent share of total finished petroleum product demand; by 1996, it had risen to 69 percent. On-highway diesel fuel showed the greatest growth, gaining 3 percentage points in market share, to reach about 11 percent of the market in 1996. The growth in gasoline and jet fuel were more modest, both gaining about 1.5 points in market share since 1984 to attain 49 and 11 percent total shares, respectively. A contributing factor in moderating the growth in gasoline demand has been the improvements in passenger car fuel efficiency. In 1984, passenger cars averaged 17.8 miles per gallon, but by 1996 they averaged well over 22 miles per gallon. This trend has stopped, partially due to increased use of minivans and sport utility vehicles. Most of the market share growth in light transportation fuels was made possible at the expense of off-highway distillate (mainly high sulfur diesel and heating oil) and residual fuel.

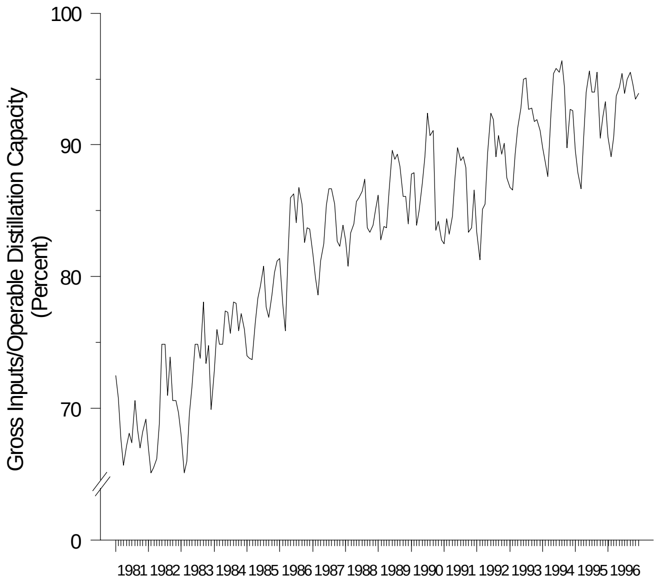
- **Premium Grade Loses Market Share with Gasoline Price Increase.** After stabilizing between 1992 and 1995, prices increased in 1996, and had a noticeable impact on the composition of gasoline grade demand. The more price sensitive (i.e., higher demand elasticity) high octane grades lost share to the lower priced regular grade. Prior to 1989, regular grade lost share as leaded gasoline was phased out and as premium and midgrade gained popularity. The decline was halted by sharply higher gasoline prices in the latter half of 1990 resulting from the Iraqi invasion of Kuwait. Premium's share peaked in 1988 at 24 percent, but then fell back, first with the advent of midgrade and later in response to the higher prices precipitated by the Gulf War. The recent price increase induced consumers to use more regular, whose share rose almost 3 percentage points to 70 percent in 1996. In contrast, premium's share fell by 2.4 percentage points to a 17-percent share in 1996, the lowest level since 1986.

- **Mild Winter Dampens 1996-97 Heating Oil Demand.** While demand for total distillate was very strong in 1996, up 4.7 percent from the prior year, the heating oil (No. 2 fuel oil) component was relatively weak, up just 2.4 percent. Most of this increase was due to severe cold weather in the first four months of 1996, which resulted in a 9.9 percent increase over the unusually mild weather occurring over the same period in 1995. However, mild weather in most of the country for the last quarter of 1996, representing the first half of the 1996-97 heating season, caused heating oil demand to drop by 4.4 percent compared to the same period in 1995. Typically, heating oil comprises about 35 percent of total distillate demand during the peak heating months, and falls to less than 20 percent during the summer. Approximately 80 percent of heating oil demand is based in the Northeast, Mid-Atlantic and Midwestern States (PADDs 1A, 1B, and 2).

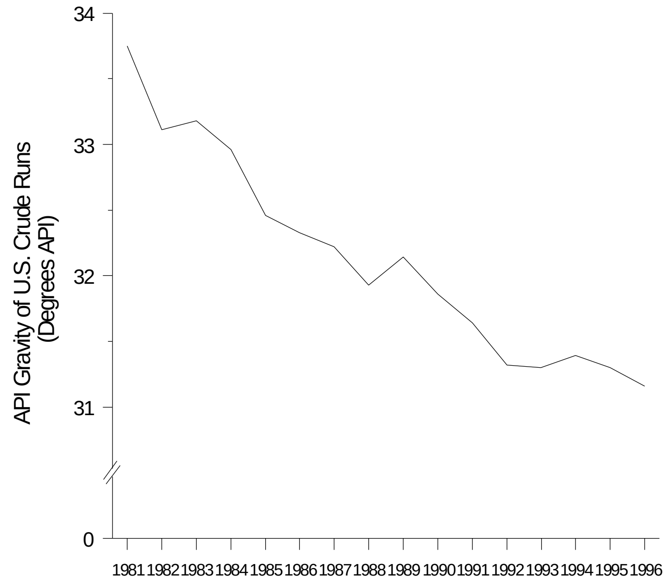
[2]For a detailed discussion on the long-term trends in residual fuel demand, refer to Energy Information Administration, *Fuel Oil and Kerosene Sales 1995* (September 1996), pp. 11-12.

Figure 7. Refinery Utilization and Downstream Capacity Increase

Domestic Refinery Utilization Continues to Rise



Move to Heavy Crude Slate Slows



Sources: **Gross Inputs/Operable Distillation Capacity** and **API Gravity:** Energy Information Administration (EIA), 1981-1995—*Petroleum Supply Annual* (Vol. 1), Table 16. 1996—*Petroleum Supply Monthly* (February 1997), Table 28.

Bottoms Processing Capacity Continues to Grow, While the Number of Refineries Declines

U.S. Refining Capacity as of January 1

Year	Number of Operable Refineries	Operable Crude Oil Distillation (MB/CD)	Operable Crude Oil Distillation (MB/SD)	Fresh Feed Catalytic Cracking (MB/SD)	Coking (MB/SD)	Hydro-cracking (MB/SD)	Hydro-treating (MB/SD)	Alkylation (MB/SD)	Isomerization (MB/SD)
1981	324	18,400	18,621	5,543	1,021	909	8,487	974	131
1985	223	15,659	16,504	5,232	1,407	1,053	8,897	917	219
1990	205	15,572	16,507	5,441	1,549	1,282	9,537	1,030	456
1995	175	15,434	16,326	5,583	1,785	1,386	10,916	1,105	502
1996	171	15,286	16,169	5,599	1,842	1,385	11,050	1,122	505
Change 1981-1996	-153	-3,114	-2,452	56	821	476	2,563	148	374
Percent Change 1981-1996	-47%	-17%	-13%	1%	80%	52%	30%	15%	285%

Sources: **1981-1995:** Energy Information Administration (EIA), Form EIA-820 "Annual Refinery Report." **1995:** The stream day capacities are projected capacities reported on Form EIA-820 "Annual Refinery Report" (1995)." **1996:** Number of refineries and crude distillation capacity from Form EIA-810 "Monthly Refinery Report" (January 1996).

U.S. Refining

Since 1980, refining capacity utilization has increased as U.S. refining capacity has declined and demand for petroleum products has increased. Refinery distillation utilization rates are now well above 90 percent, but capacity constraints are not yet evident in the marketplace. Much of recent refinery facility investment has been for expansion and debottlenecking of units downstream of the distillation units, partially in response to environmental requirements.

- **Domestic Refinery Utilization Rates Continue to Rise.** The utilization rate for U.S. refineries rose in 1996 to meet rising oil demand with virtually unchanged refinery capacity. The average monthly utilization rate increased from 92.0 percent to 93.4 percent from 1995 to 1996. Normally, utilization rates are lower in February and March because of refinery maintenance, and highest in summer when throughput increases to meet gasoline requirements. In the last several years peak utilization rates exceeded 95 percent, while the minimum was under 90 percent. Utilization rates in excess of 95 percent caused some market analysts to suggest that utilization rates are approaching an upper limit and may result in heightened market stress. Using EIA's definition of utilization, 95 percent still leaves room for significant production. EIA defines refinery utilization rate as input divided by calendar day capacity, which means that 100 percent is the theoretical maximum average rate. The calendar day rate has already been adjusted down from the stream day capacity to account for shutdown and production disruptions. In months with few shutdowns, rates can exceed 100 percent.[3]

- **Move to a Heavier Crude Slate Slows.** The average API gravity of crude oils run in U.S. refineries fell for many years, but leveled off in recent years. While crude input grew heavier and then stabilized, production of heavy products decreased. In 1980, heavy residual fuel represented 11.7 percent of the product barrel. By 1985 residual fuel yield fell to 7.1 percent, and in 1995, it was only 5.4 percent. As crude oil gravity decreases, the fraction of heavy material in the crude increases; however, this heavy material can be converted to light product with one of several bottoms conversion processes. In the U.S., coking is the bottoms conversion process most commonly used.

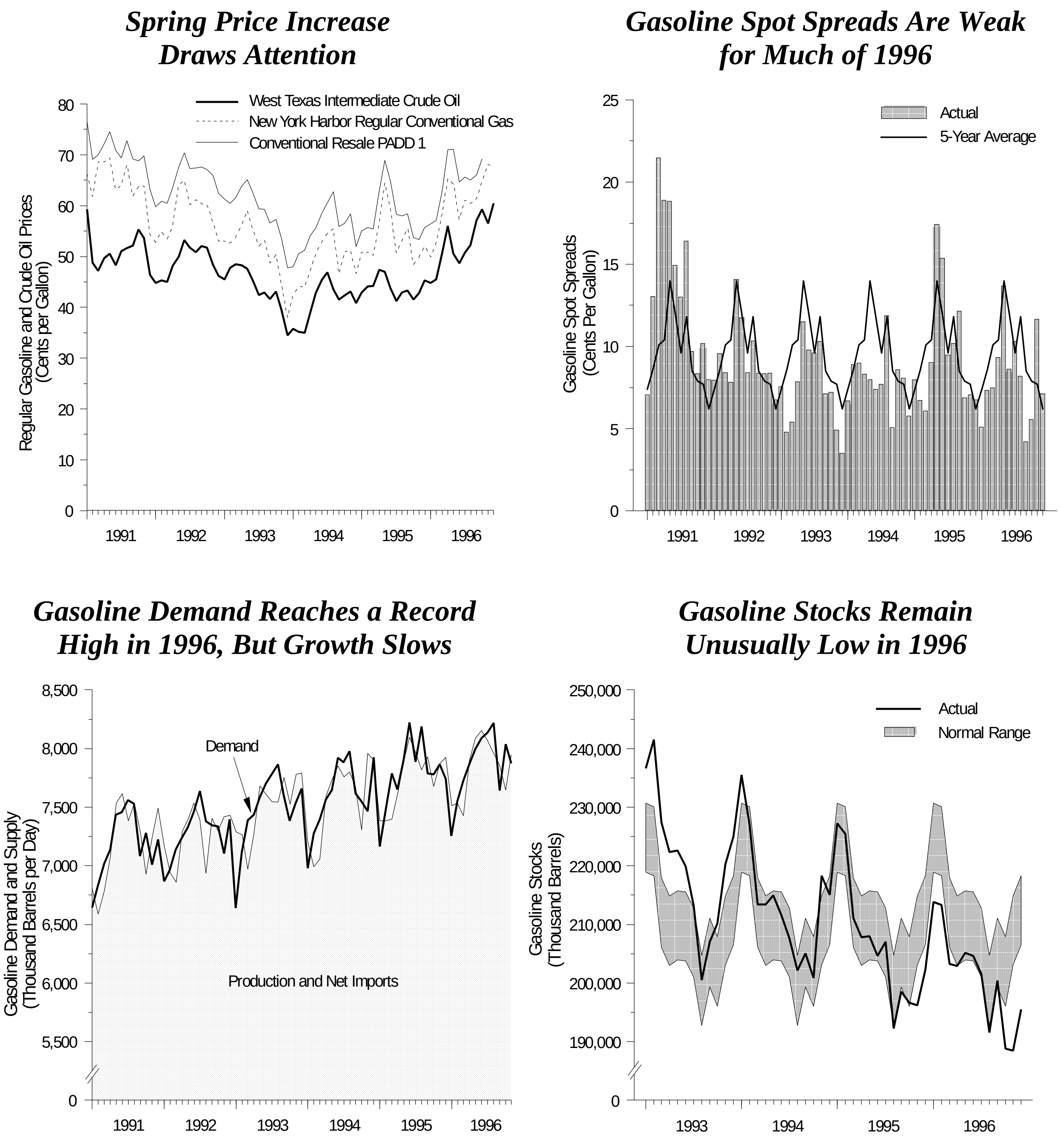
- **Bottoms Processing Capacity Continues to Grow.** Coker unit capacity grew rapidly in the early 1980's, and continues to grow, but at a more modest rate. From 1990 to 1996 coker capacity increased 19 percent. Utilization rates for cokers are the highest of all the process units EIA tracks. The decline of the price differential between light and heavy crudes and light and heavy products (discussed in Chapter 7) has reduced the economic attractiveness of investing in additional coker capacity. The continuing high utilization rates for cokers in the 1990's suggests that, on a variable cost basis, continued operation is justified; however, investment return may have declined or disappeared entirely at times.

- **Environmental Requirements Drive Facilities Decisions in the 1990's.** Refiners' investment decisions in the 1990's were driven by requirements for cleaner fuels and stricter environmental regulation of refineries. The Clean Air Act Amendments (CAAA) of 1990 resulted in new requirements for gasoline and diesel fuel. In California, state regulations required even greater changes to product quality. A CAAA requirement to reduce diesel sulfur content to 0.05 weight percent caused a 827 thousand barrels per day increase in middle distillate hydrotreating capacity from 1990 to 1995. Additionally, a substantial number of process revamp projects enabled units to achieve the 0.05 wt percent product sulfur level. The CAAA reformulated gasoline requirement resulted in an increase of 7.3 percent in alkylation capacity and of 10 percent in isomerization capacity from 1990 to 1996. The most dramatic increase in the period was the increase in oxygenate production facilities. In 1995 ether (MTBE & TAME) production capacity in the U.S. was 269 thousand barrels per day, compared to 120 thousand barrels per day estimated capacity in 1990.

- **The Number of Refineries Continues to Decline.** Between January 1, 1990 and January 1, 1997, the number of operable refineries in the U.S. declined from 205 to 164; although capacity remained roughly the same. Thirty-five refineries with a total capacity of 571 thousand barrels per day capacity were shut down and not reactivated, and the primary distillation capacity of a large refinery (Transamerican) decreased from 300 thousand barrels per day to 0. There were seven new or reactivated refineries that added 131 thousand barrels per day to distillation capacity. That means that existing refineries increased capacity by about 304 thousand barrels per day. Most of the focus of U.S. refiners was on downstream facilities, but as part of refinery projects there was some debottlenecking and expansion of primary distillation facilities.

[3] Tancred Lidderdale, Nancy Masterson, Nicholas Dazzo, "Secondary Process Key to Gauging U.S. Refining Capacity," *Oil and Gas Journal* (February 5, 1996), pp. 54-57.

Figure 8. Gasoline Prices Draw Public Attention



Sources: **Spot Prices:** Standard and Poor's Platts. **Resale Prices:** Energy Information Administration (EIA), 1991-1994—*Petroleum Supply Annual* (Vol. 1), Table 31. 1994-1996—*Petroleum Supply Monthly* (February 1997), Table 32. **Spot Spreads:** Standard and Poor's Platts. **Gasoline Demand and Supply** and **Gasoline Stocks:** EIA, 1991-1995—*Petroleum Supply Annual* (Vol. 1), Table S4. 1996—*Petroleum Supply Monthly*, Table S4.

U.S. Gasoline Markets

The sharp increase in gasoline prices in the spring of 1996 aroused much public concern. Although gasoline demand was strong and stocks were low, it was high crude oil prices that caused much of the spring price increase and drove gasoline prices up again later in the year.

- **Spring Gasoline Price Increase Draws Attention.** The usual seasonal spring increase in gasoline prices was given a large boost this year from rising crude oil prices. As the winter of 1995-96 drew to a close, gasoline and petroleum stocks were low worldwide. Colder weather lingered, and winter heating fuel demand persisted, pushing crude oil prices higher beginning in February. Finally a late, unexpected cold snap hit both Europe and the United States, sending refiners into the market for additional crude oil to meet the spurt in demand for heating fuel. Crude prices experienced a final burst, with WTI topping $25 per barrel in April 1996, just when gasoline markets are normally tightening at the beginning of the summer driving season.

- **Gasoline Spot Spreads Are Weak for Much of 1996.** The seasonal spring increase in gasoline spot spread (spot gasoline price minus crude oil price) was not much different than average, in spite of the low gasoline stocks. But the extra push from the underlying crude oil price increase raised the total spring gasoline price substantially. Spot Gulf Coast gasoline prices rose from 48.0 cents per gallon in December 1995 to peak at 66.2 cents in April 1996. Retail gasoline prices, which lag behind crude oil price increases, did not peak until May. Retail conventional regular gasoline prices rose from a low of $1.06 in mid-February to a high of over $1.25 on May 17. Crude oil prices and gasoline prices fell back after the spring increase, but by fall, crude oil prices were again climbing (see World Oil Markets page), and gasoline prices followed. By the end of December, gasoline prices were back at levels seen during the spring runup.

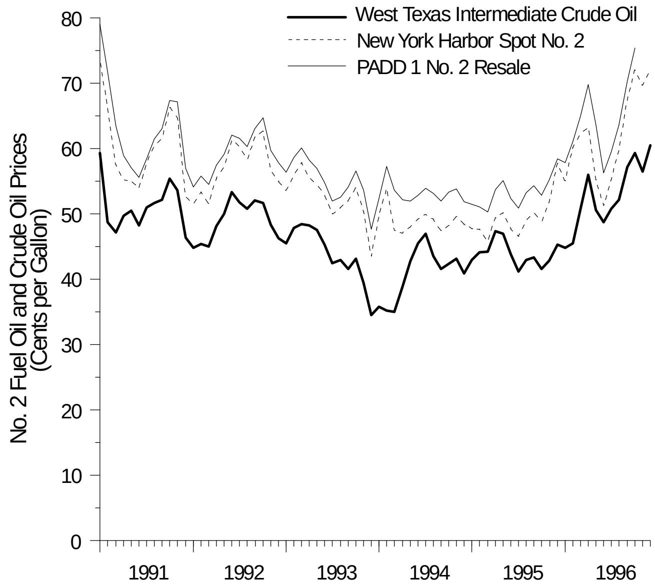
- **Gasoline Demand Reaches a Record High in 1996, but Growth Slows.** Gasoline demand began the 1990's with little growth as the United States experienced a recession. However, growth resumed in 1992, averaging 2.3 percent annually through 1995. Growth slowed again in 1996. Gasoline consumption only grew 0.8 percent in 1996 as bad weather slowed travel in the first quarter and high prices discouraged consumption. Despite this slow growth, U.S. gasoline demand in 1996 was 7.85 million barrels per day, a record high, rising from 7.79 million barrels per day in 1995.

- **Gasoline Production in 1996 Is Stable but Imports Are Higher.** The increase in gasoline demand in 1996 was satisfied overall by increases in net imports. Total production in both 1995 and 1996 averaged 7.59 million barrels per day. Imports, on the other hand, were stronger in 1996 than 1995. This happened for several reasons (see Chapter 2), including a glut of gasoline production in Europe. While exports in 1996 were almost the same as in 1995, imports of finished gasoline and blending components averaged 469 thousand barrels per day in 1996 compared to 313 thousand barrels per day in 1995. Reformulated gasoline (RFG) represented 37 percent of gasoline and blending component imports in 1995 and 39 percent in 1996. (The East Coast is the main area using gasoline imports, and much of this region converted to RFG.) Lackluster price premiums for the costlier RFG and regulatory uncertainties were some of the factors keeping imports down in 1995.

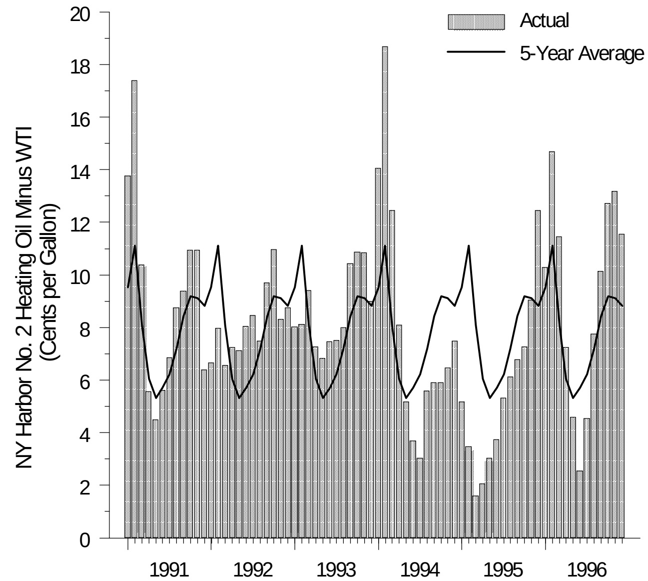
- **Gasoline Stocks Remain Unusually Low in 1996.** Although total gasoline stocks have been exhibiting a long-term downward trend (see Chapter 6), stocks in 1996 were even lower than the trend would indicate. Stocks began the year low at 202.3 million barrels (ending December 1995), which was 11 million barrels (5 percent) lower than the previous December minimum that occurred at the end of 1989. Stocks returned to the low end of the normal range by the end of April, and high imports and production kept them at the lower edge of the normal range through the driving season. In October, refinery problems caused stocks to drop to 188.8 million barrels, the lowest observed minimum in any month since EIA began collecting data in 1981. Stocks did not recover in November, and buyers, concerned over supply availability, drove prices up. Crude prices, on the other hand, fell back briefly in November as European refiners slowed their pursuit of distillate-rich crude oils. The combination of increased gasoline market pressures and declining crude prices led to a strong increase in U.S. spot gasoline spreads for the month of November. According to trade press reports, the gasoline price rally attracted more cargoes of imports, and the spread soon declined, but increasing crude oil prices pushed total prices higher in December. Stocks remained abnormally low through December, ending the year at 195.5 million barrels, the lowest December stock level recorded by EIA.

Figure 9. World Distillate Demand Keeps Pressure on Crude Prices

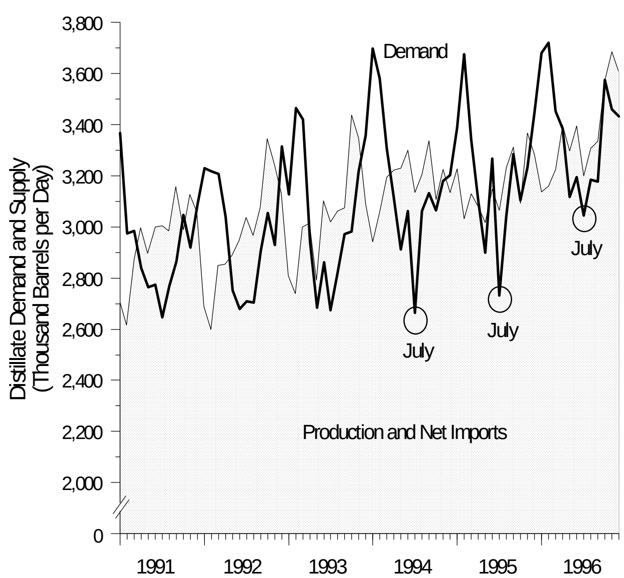
Tight Distillate Market Pulls Crude Prices Up . . .



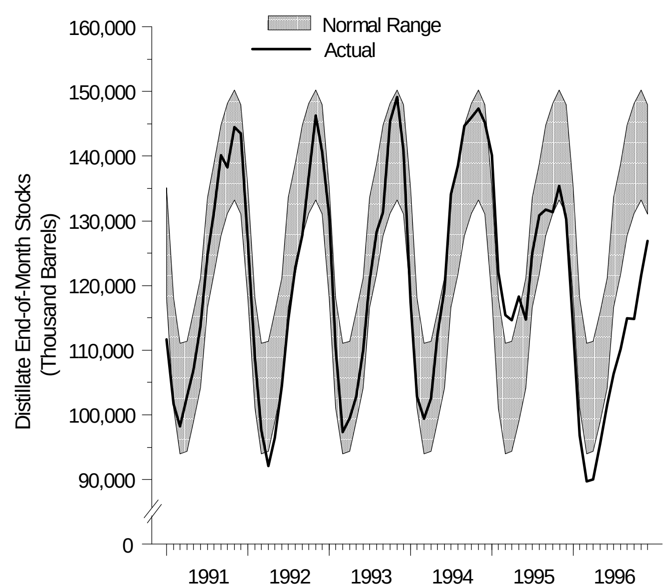
. . . and Boosts Spot Spreads Above Average for Most of 1996



Strong Distillate Demand Reinforces Market Tightness



Distillate Stocks Drop to Record Low Levels in Fall 1996



Sources: **Spot Prices:** Standard and Poor's Platts. **Resale Prices:** Energy Information Administration (EIA), 1991-1993—*Petroleum Supply Annual* (Vol. 1), Table 40. 1994-1996—*Petroleum Supply Monthly* (February 1997), Table 40. **Spot Spreads:** Standard and Poor's Platts. **Distillate Demand and Supply** and **Distillate Stocks:** EIA, 1991-1995—*Petroleum Supply Annual* (Vol. 1), Table S5. 1996—*Petroleum Supply Monthly*, Table S5.

U.S. Distillate Markets

A cold winter worldwide in 1995-96 drove up distillate demand. Refiners drew down petroleum inventories, and then increased crude oil purchases and runs to produce additional distillate, pulling crude oil prices higher. In the U.S., distillate demand did not let up over the summer, and inventories never recovered. As fall approached, crude markets worldwide remained tight and crude oil prices again climbed. With distillate markets in the U.S. still tight, prices stayed strong throughout the year.

- **Tight World Distillate Market Pulls Crude Oil Prices Up and Boosts Spot Spreads Above Average for Most of 1996.** While gasoline prices drew the most publicity in the spring of 1996, distillate prices also increased. As winter 1995-96 progressed, distillate demand increased, and distillate markets worldwide tightened. The growing tightness was reflected in lower than normal inventories and higher than normal price spreads over crude oil (spot distillate price minus crude oil price). Winter continued into March, depleting distillate inventories, so European and U.S. refiners turned to the crude markets for additional oil to produce more distillate. Crude prices were pulled higher. The higher crude prices and higher than normal price spreads continued until distillate demand let up after the April cold snap.

- **Distillate Market Tightness Spreads to Crude Market in Fall.** Price spreads fell back below normal in June and July, but began to pick up again in August, even before the heating season was underway. Strong demand coupled with the low inventories resulted in early distillate price pressure. With worldwide petroleum inventories still low, crude prices again were pulled higher as the distillate heating oil season got underway. Tight U.S. distillate markets kept distillate price spreads above average through the remainder of 1996. The higher spreads coupled with high crude oil prices resulted in high distillate prices throughout 1996.

- **Strong Distillate Demand Reinforces Market Tightness.** Distillate fuel oil serves several end uses. On-highway transportation represents almost 50 percent of demand. Residential heating, the next largest end-use category, represents more than 13 percent of annual distillate use,[4] but is concentrated in the winter months. Annual distillate fuel oil demand grew 4.7 percent over 1995 due to both cold weather in early 1996 and high transportation demand.

- **Jet Kerosene Demand Is Also High.** Not only did distillate fuel oil demand grow at a brisk pace, but kerosene-type jet fuel also showed strength, averaging 6.0 percent growth in 1996. This product and distillate come from essentially the same boiling range of the crude oil barrel, so its high growth put further pressure on distillate supply.

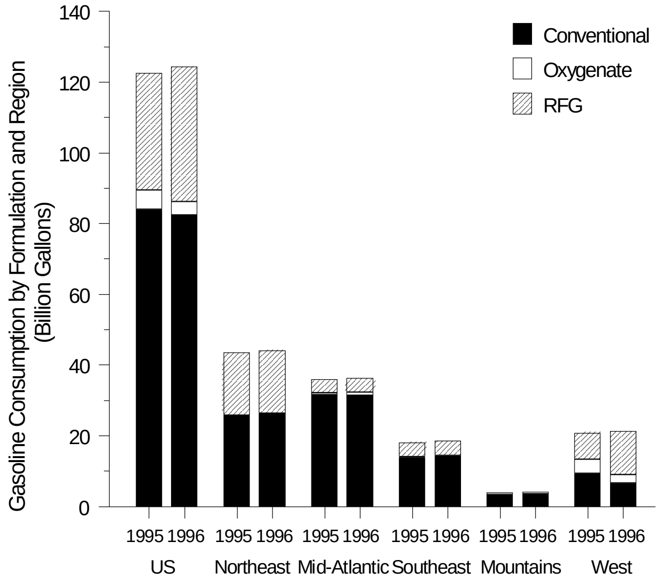
- **Production and Net Imports Increase, but Still Fall Short of Demand.** Distillate demand rose 161 thousand barrels per day in 1996 to average 3,368 thousand barrels per day. Production rose 170 thousand barrels per day to 3,325 thousand barrels per day and net imports increased 24 thousand barrels per day, requiring 9 thousand barrels per day to be met from stocks. While total net imports only increased 24 thousand barrels per day over 1995, the trading patterns were much different, which is explained further on the Import Overview page.

- **Distillate Stocks Drop to Record Low Levels in the Fall.** The most unusual feature of the distillate market in 1996 was the very low inventory levels that persisted throughout the year. U.S. distillate inventories bottomed out in March at 89.7 million barrels, the lowest level since EIA began collecting data in 1981. After the April cold snap, stocks were still low at 90.0 million barrels, well below the normal range for that time of year. By June, inventories looked like they might have a chance to climb back, but strong July demand prevented the needed stock increase. Distillate stock build is usually highest in July, averaging 11.4 million barrels, but in 1996, the stock build was only 4.7 million barrels, the lowest July stock build since EIA began collecting data. The gap only grew through October, with fuel oil inventories closing the month at 115 million barrels, 6 million barrels below the next lowest stock level recorded for October in history. Distillate stocks are an important supply source during the peak winter demand months, and on average satisfy about 12 percent of demand from December through February. Thus, low inventories going into winter are a concern. Any early cold snap would have caused prices to soar, as happened in December 1989, when stocks also were low and an early cold spell drove prices up. Fortunately, in 1996, no such cold spell occurred, but the continued high demand, high production, and low stocks kept price spreads well over average.

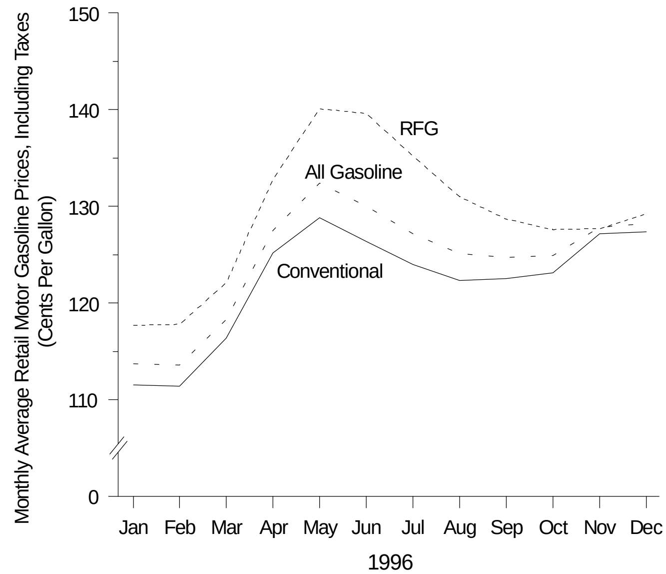
[4]Energy Information Administration, *Fuel Oil and Kerosene Sales 1995* (September 1996), Table HL1.

Figure 10. Clean and Alternative Transportation Fuels Continue to Grow

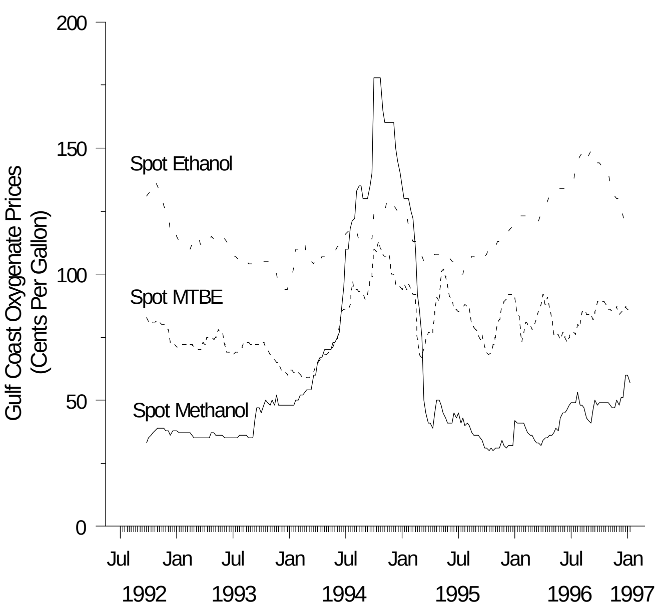
Reformulated Gasoline Increases Market Share



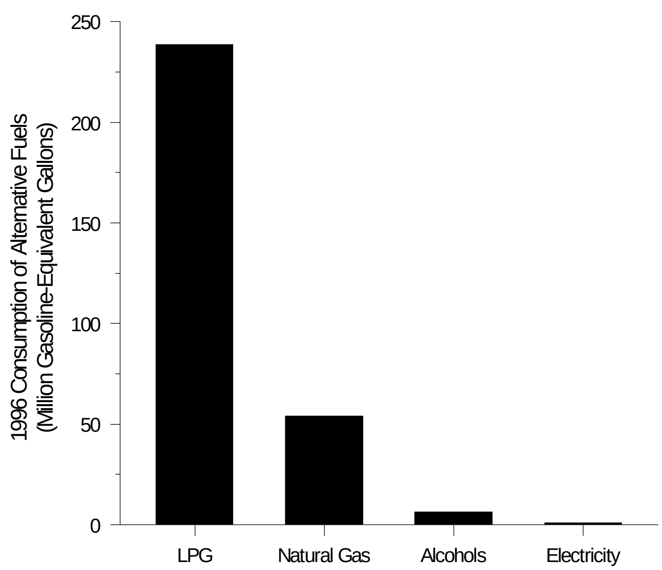
Switching to Cleaner Gasolines Has a Price



Oxygenate Prices Rise Steadily for Much of 1996



Propane Is the Dominant Alternative Transportation Fuel



Sources: **Gasoline Consumption:** Energy Information Administration (EIA), *Prime Supplier Report*, December 1996. **Gasoline Prices:** EIA, *Weekly Petroleum Status Report* (various issues). **Oxygenate Prices:** *Octane Week* (various issues). **Consumption of Alternative Fuels:** EIA, *Alternatives to Transportation Fuels* (December 1996).

Clean and Alternative Transportation Fuels

The use of cleaner transportation fuels to improve air quality continued to grow in 1996. Smog-reducing reformulated gasolines were chiefly responsible for this increase. While the use of alternative fuels also increased, it will be many years before alternative fuel vehicles become a significant factor in the transportation sector.

- **Reformulated Gasoline Increases Market Share.** Reformulated gasoline (RFG), which is designed to reduce harmful exhaust emissions that cause smog, accounted for 31 percent of total motor gasoline usage in 1996, up from 27 percent in 1995. On the other hand, oxygenated gasoline, which is designed to reduce emissions of carbon monoxide, comprised only 3 percent of motor gasoline sales in 1996, down from 4.4 percent in 1995. The Northeast and the West Coast are the biggest users of RFG.

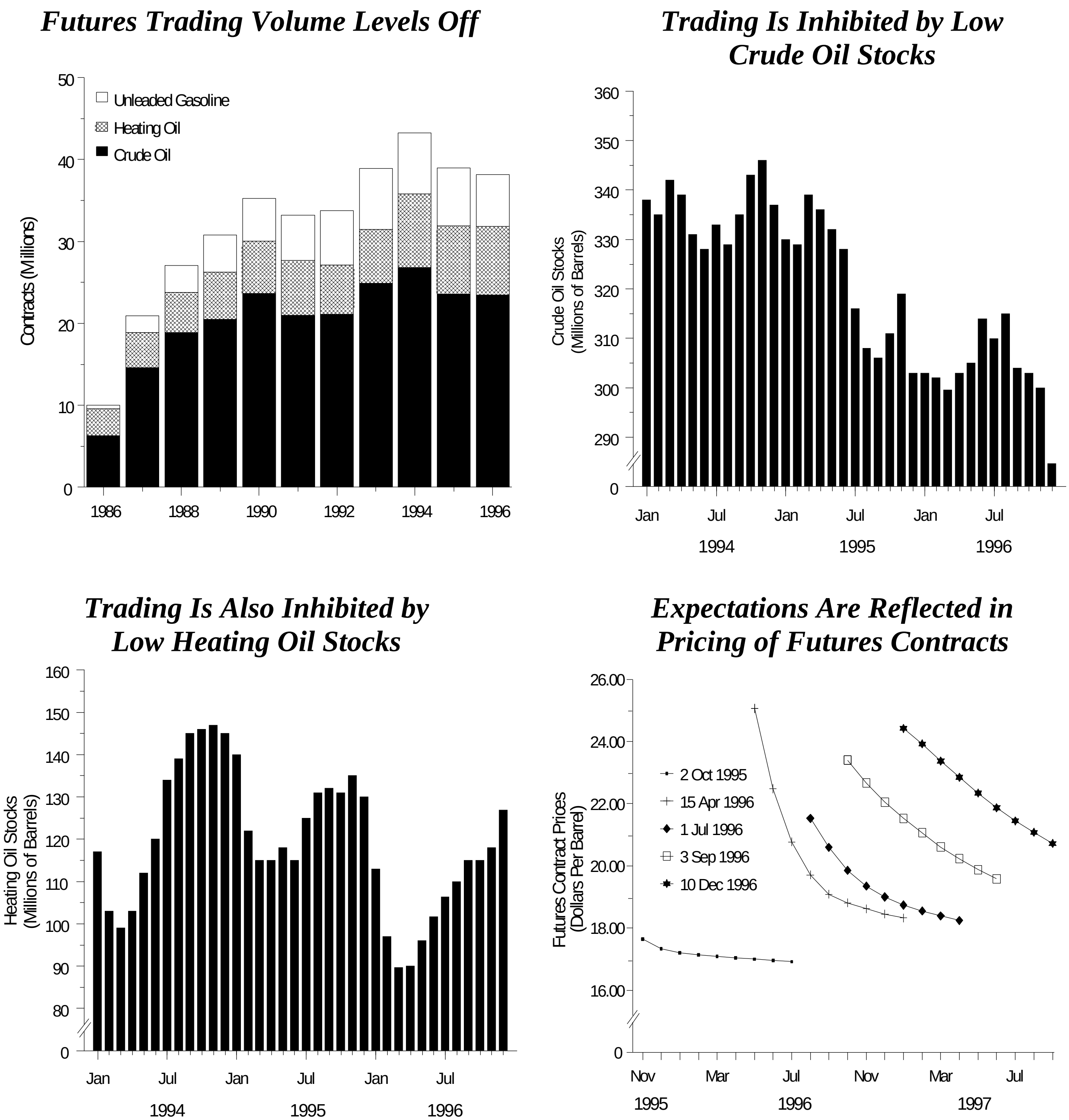
- **The Switch to Cleaner Gasolines Has a Price.** In areas where RFG is used, consumers sometimes pay significantly more for this fuel than they would for conventional gasolines. Gasoline prices are generally relatively high to begin with in these areas, which tend to be more densely populated. Prior to the introduction of RFG, these areas showed about a 2-cent-per-gallon price premium over attainment (non-RFG) areas. Adding in the incremental cost of producing RFG, which EIA calculated to be about 3 cents per gallon, and the extra increase in logistics and other costs, which the National Petroleum Council estimated at about 1 cent per gallon, the typical spread between RFG and conventional gasoline is expected to average about 6 cents per gallon. California's RFG has more stringent requirements than the Federally mandated RFG, and its production costs are also higher, leading this spread to be even wider in California. California also has had supply problems due to refinery operating difficulties and the limited number of refineries that can produce the gasoline, which has driven RFG prices there up even further. California consumes over 35 percent of the nation's RFG, so its prices affect national average figures. The differences between the Gulf Coast spot prices for reformulated and conventional regular gasoline provide an indication of the RFG premium being paid by consumers outside of California. Gulf Coast monthly average spot RFG-conventional differences averaged 2.3 cents per gallon in 1996, varying between 3.9 cents per gallon in April and 0.8 cents in October. Adding on the 2-cent RFG regional differences and 1 cent logistical costs, retail customers outside of California probably paid on average a little over 5 cents more for RFG in 1996.

- **Oxygenate Prices Rise Steadily for Much of 1996.** Oxygenates are an important component of reformulated gasolines. Oxygenate prices in 1996 were less volatile than in the previous few years, but nevertheless they were affected by numerous special circumstances. The price of corn reached $5.00 per bushel in June 1996, compared to $2.00 per bushel as recently as October 1994. This affected ethanol prices, which rose steadily on the Gulf Coast from $1.05 per gallon in September 1995 to as high as $1.49 per gallon in September 1996. Methanol prices were much more stable in 1996 than in recent years, but tight supplies, worsened by idled plants, including the Callowness plant in Alberta, Canada, in early October and the Hoechst-Celanese plant in Clear Lake, Texas in December, drove methanol prices to a high of 51 cents per gallon in December. Because methanol is a feedstock for MTBE, higher methanol prices in turn pushed up the price of MTBE, which traded as high as 89 cents per gallon in October.

- **Propane Is the Dominant Alternative Transportation Fuel.** Liquefied petroleum gases (LPG), predominantly propane, are by far the dominant alternative fuel, although the use of other alternative fuels is growing. In 1992, natural gas, including both compressed natural gas and liquefied natural gas, comprised less than 6 percent of alternative fuels use, but by 1995, EIA estimates its share had risen to almost 15 percent.[5] The use of alcohols is small, involving various mixtures of ethanol and methanol with gasoline. Electricity will be a small factor in the market for the foreseeable future. Overall, most of the growth in alternative fuel usage is the result of the Energy Policy Act of 1992, which mandated the use of alternative fuels in Federal government fleets in 1993 and in state and local government fleets over the next few years.

[5]Energy Information Administration, *Alternatives to Traditional Transportation Fuels 1994* (February 1996), Volume 1, Table 14.

Figure 11. Futures Markets Are Turbulent in 1996



Sources: **Futures Trading Volume** and **Futures Contract Prices:** New York Mercantile Exchange. **Crude Oil** and **Heating Oil Stocks:** Energy Information Administration, *Petroleum Supply Monthly* (various issues).

Petroleum Futures Markets

By any measure, petroleum futures markets were extremely volatile in 1996. Volatility frequently attracts increasing amounts of both speculative and hedging activity in futures markets; however, this has not occurred recently. Trading volume in energy futures grew at a remarkably rapid rate in the late 1980's, but volume growth has slowed considerably in recent years. There are many reasons for this. An important reason is that commercial traders historically have been attracted to futures markets as a device for hedging their price risk. But futures contracts that do not accurately reflect the product being hedged may have price movements that differ greatly from spot price movements, diminishing the usefulness of the futures contract as a hedging device.

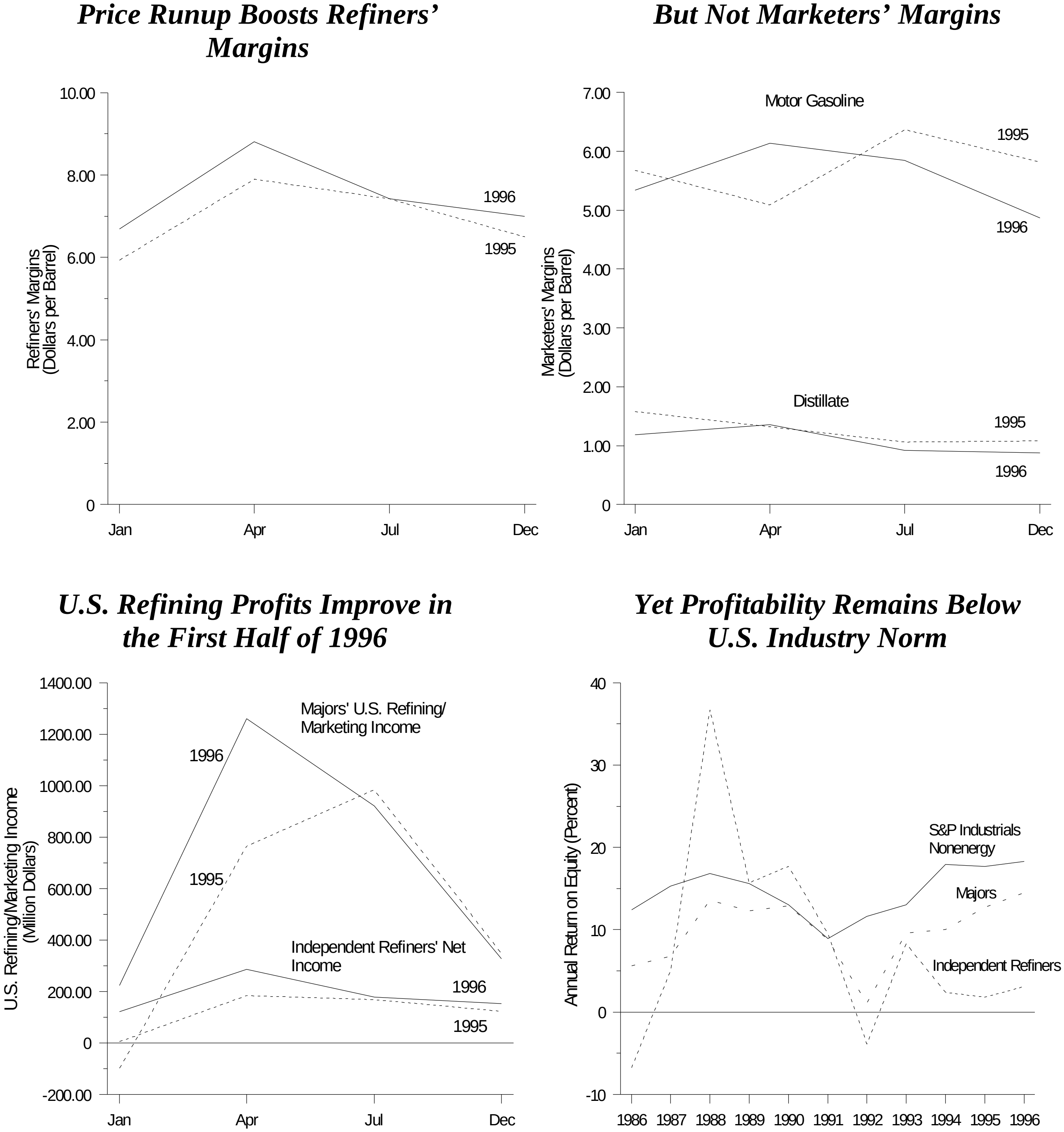
- **Futures Trading Volume Levels Off.** Uncertainty in unleaded gasoline futures trading is one of the major reasons why futures market trading volume has leveled off since 1994. Unleaded gasoline futures are specified in terms of reformulated gasoline but must serve as a hedging device for numerous types of reformulated, oxygenated, and conventional gasolines. The fragmented gasoline market causes great uncertainty as to how closely futures prices will follow the spot prices of the type of gasoline being hedged. That uncertainty has led to a slowing in trading volume in unleaded gasoline futures. After large increases in volume as recently as 1988 (60 percent) and in 1989 (36 percent), trading in gasoline futures actually decreased by 5.3 percent in 1995 and another 0.5 percent in 1996.

- **Low Oil Stocks Also Inhibit Trading.** Another reason for the slowdown in futures trading volume is the effect that low oil stocks have on the markets. Price structures in energy futures markets depend upon a variety of factors. The most important factor by far is the balance between supply and demand that is reflected in the level of stocks. Low stock levels in a tight market can adversely affect the relationship between futures prices and spot prices almost as much as having an inadequately defined futures contract. Heating oil and crude oil stocks reached historically low levels in 1996. In March 1996, heating oil stocks reached a low of 89.7 million barrels, down 22 percent from the previous year, and at a very low level to begin building stocks for the heating season. Also, crude oil stocks were only 299.6 million barrels in March 1996, down 11.6 percent from a year earlier. Low stock levels can make the markets very jittery, and futures prices and spot prices may behave very differently, making the futures markets less useful for hedging and thereby causing a slowing in the volume of futures trading.

- **Numerous Factors Contribute to Low Stock Levels of Petroleum and Products.** One factor affecting stocks is loosely called "just-in-time" inventory practices. The industry has made a conscious effort to lower inventory costs by holding as few stocks as possible. At least part of the low stocks in 1996 were simply an extension of a long-term trend in the industry to hold fewer stocks. Additionally, a number of supply and demand factors contributed to low stock levels in 1996. Those factors include: an industry-wide reflection of expectations about the possibility of the resumption of oil sale from Iraq; cold weather in the spring; strong global oil demand; supply shortfalls from non-OPEC sources; and strong gasoline demand. All those factors made it difficult for refiners to build inventories.

- **Pricing of Futures Contracts Reflects Stock Levels and Supply Expectations.** Through 1996, the futures markets reflected changing stock levels and expectations of future supply (market factors that are not independent). In late 1995, the crude oil market showed only mild "backwardation," a situation in which crude oil for future month delivery is priced lower than crude oil for nearby month delivery. On October 2, crude oil for delivery in November was $17.64 per barrel, while crude oil for December 1996 delivery was only 30 cents per barrel lower. But by April 1996, the backwardation in the crude oil futures market had increased sharply. On April 15, 1996, crude oil for May delivery was $25.06 per barrel, but oil for June delivery was $2.58 per barrel lower, driven largely by expectations of imminent oil sales from Iraq. In early December 1996 the backwardation decreased after Iraqi oil sales were finally announced, as the spread between January and February 1997 futures prices dropped to 50 cents per barrel. The announcement of the Iraqi sales removed much of the uncertainty in expectations that had caused market backwardation. Futures markets will continue to be a good measure of both perceived adequacy of petroleum stock levels to cushion supply/demand swings and market expectations. They may also cause some controversy, as analysts disagree on the exact nature of the cause-and-effect relationships between futures market backwardation, stock levels, and expectations.

Figure 12. Downstream Performance in 1996 Is Modest Despite High Prices



Note: **Profitability:** Return on equity = net income as a percent of stockholders' equity. Results for 1996 are through the third quarter.

Sources: **Refiners'** and **Marketer's Margins:** Energy Information Administration, *Petroleum Marketing Monthly* (April 1997) (Washington, DC). **U.S. Refining Income and Profits:** Company quarterly reports to shareholders. **Profitability:** Standard and Poor's Compustat.

Financial Performance

Increases in gasoline and distillate margins raised refinery margins slightly higher in 1996, but lower retail margins dampened growth in downstream income. While total profitability of the major and independent refining companies was up in 1996, it remained below the profitability of overall U.S. industry.

- **Price Runup Boosts Margins in the First Half of 1996.** The spread between product prices and crude oil input costs (the gross refining margin) realized by refiners for distillate and gasoline was nearly a dollar per barrel higher in both the first and second quarters of 1996 than corresponding 1995 levels. It should be noted that the gross refining margin in the first quarter of 1995 was at a 6-year low. The increase in the first-quarter margin in 1996 reflected the effects of an especially cold winter, particularly in March, with heating oil prices up 17 percent and propane prices up 22 percent compared to prices in the first quarter of 1995. However, the first-quarter rise in gasoline prices merely matched the rise in crude oil input prices. In the second quarter of 1996, gasoline price rises out paced the continued rise in crude oil input costs, as did distillate prices, thereby contributing to higher margins.

- **U.S. Refining Profits Improve in the First Half of 1996.** Quarterly financial results are available for a consistent group of 13 specialized refiner/marketers and 13 major integrated petroleum companies that separately report data for their U.S. refining/marketing line of business. Total first-quarter income from U.S. refining/marketing operations for both groups of companies in 1996 was over $400 million above the very poor first-quarter results of 1995. The first-quarter results in 1995 were the worst for U.S. refining operations over the 1987-1996 decade. The rise in downstream profits continued through the second quarter of 1996. The majors' second-quarter financial results for their U.S. refining/marketing operations were at a 10-year peak, surpassing the previous peak in 1990, when a crude oil market glut yielded record refining margins. Independent refiners also registered a 10-year peak in second quarter net income.

- **High Margins Are Not Sustained in the Second Half of 1996.** In contrast to the first-half results, refiners' margins in the second half of 1996 were only slightly above prior year's margins. Gross margins showed the typical seasonal pattern, dropping in the third quarter from the second quarter's level. The gross margin in the third quarter of 1996 almost matched 1995's third-quarter margin, while the margin in the fourth quarter was 8 percent above the comparable value in 1995. The modest uptick in margins was largely due to higher gasoline and diesel fuel demand stemming from a surge in U.S. economic growth in the last quarter of 1996.

  Refiners registered a year-over-year drop in income in the second half of 1996, even though margins were slightly higher and overall U.S. refined product demand was up 3 percent. Reduced retail margins appear to be a source of lower downstream earnings in the second half of 1996. The retail margin for gasoline (calculated as the difference in the price to end users and the resale price) was clearly lower in the second half of 1996 compared with 1995. Since most of the majors and independent refiners are involved in retail gasoline marketing to varying degrees, a large drop in retail margins will be reflected in their bottom-line results.

- **Refiners' Profitability Improves, but Remains Below U.S. Industry Norm.** On balance, the profitability of the U.S. major and independent refining companies in 1996 was up slightly, but still well below the profitability of U.S. industry overall. An often-used measure of corporate profitability is return on equity, defined as net income as a percent of stockholders' equity. Although the annual profitability of both the majors and independent refiners rose in 1996, this improvement was mainly attributable to lines of activity other than U.S. refining and marketing operations. Major U.S. petroleum companies' upswing in overall profitability was traceable to higher oil and natural gas prices realized from upstream operations. For example, the majors disclosing separate financial results for U.S. oil and gas production reported that income from these operations for all of 1996 was up 88 percent compared with results for 1995. For their U.S. refining and marketing operations, the majors reported a much smaller 15-percent increase in income over the same period.

  The independent refiners' increased profitability in 1996 in part reflected recent large downstream acquisitions (Clark USA and Tosco) and improved results from other lines of activity including nonenergy businesses (Ashland) and the production and marketing of natural gas and natural gas liquids (MAPCO, LL&E, and Valero Energy).

2. Spring '96 Gasoline Price Runup: An Example of Petroleum Market Dynamics

The rapid increase in gasoline prices during spring 1996 focused attention on petroleum markets. Petroleum product prices have not drawn much public attention since the Gulf War, but the spring increase renewed interest in the changing petroleum marketplace and raised questions about what caused the increase and the potential for more such price increases in the future.

Introduction

Retail gasoline prices in the United States rose sharply over the early months of 1996, increasing by 21 cents between mid-February and mid-May[6] (Figure 13). While gasoline prices usually rise somewhat at this time of year, the extraordinary speed and magnitude of the increase surprised and even alarmed many consumers.

The spring 1996 price increases resulted from a confluence of factors, some of which were unusual but not unprecedented. Rising crude oil prices and the normal seasonal increase in gasoline prices accounted for most of the retail price increase. However, gasoline markets were also affected by unusual factors, including: a late-winter cold spell causing refiners to focus on producing distillate (heating oil, diesel fuel and kerosene-jet fuel) instead of gasoline longer than usual; lower-than-normal gasoline stocks; continuing high gasoline demand and high refinery capacity utilization; and persistent expectations that both crude oil and gasoline prices would fall several months in the future, which discouraged production of gasoline in excess of demand to build stocks.

In order to assess the main factors influencing gasoline prices, crude oil price movements are separated from the gasoline prices, and spot prices will be explored separately from retail prices. The difference between gasoline price and crude oil cost is referred to as the price spread. Figure 14 shows the relationships between spot and retail prices and the underlying costs that prices must cover, excluding taxes. The full retail price of gasoline paid by consumers provides the revenues to cover the costs of crude oil, refining, storage and distribution, marketing and retail expenditures, taxes (federal, State and local), and to generate a return on investment (profits). The two largest single costs are crude oil and taxes (Figure 15). For example, West Texas Intermediate spot prices averaged 45.3 cents per gallon during December 1995. Taxes averaged 40.8 cents per gallon.

Average monthly spot prices peaked in April at over 65 cents per gallon, and retail prices, which lag spot price changes, peaked a month later in May at $1.24. Figures 15 and 16 show that the crude oil price increase explains a large part of the gasoline price increase. However, gasoline spreads also increased. Spot gasoline spreads normally increase between December and May, followed shortly by increases in retail prices. Figure 16 shows what spot prices would have been, had average spot spreads been experienced.[7]

This chapter describes the influence of various market factors on gasoline prices and how these factors combined to cause the unusual price increases in the spring of 1996. The analysis focuses on the changes that occurred from December, the normal seasonal low point for spot gasoline markets, through April, when spot prices peaked, follows the progress of gasoline markets prices through the summer driving season, and concludes with the price reversal in spring 1997.

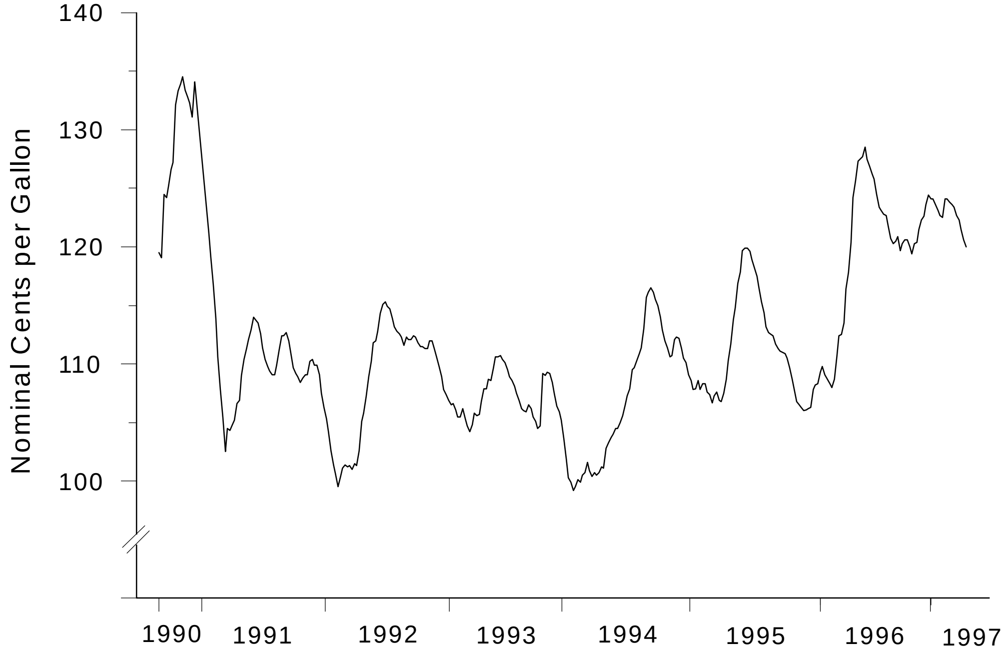
Crude Oil Market in Spring 1996

Crude oil, the raw material for gasoline and other petroleum products, represents by far the largest cost component of those products. The increase in crude oil prices from December 1995 through April 1996 explains about half of the increase in retail gasoline prices. Light and heavy crudes alike rose rapidly in March and April (Figure 17). West Texas Intermediate (WTI) crude oil averaged $19.03 per barrel in December, fell back to under $18 towards the end of January, and peaked at $25.15 per barrel during April

[6]Regular gasoline, all formulations: Energy Information Administration (EIA), Form EIA-878, "Motor Gasoline Price Survey."

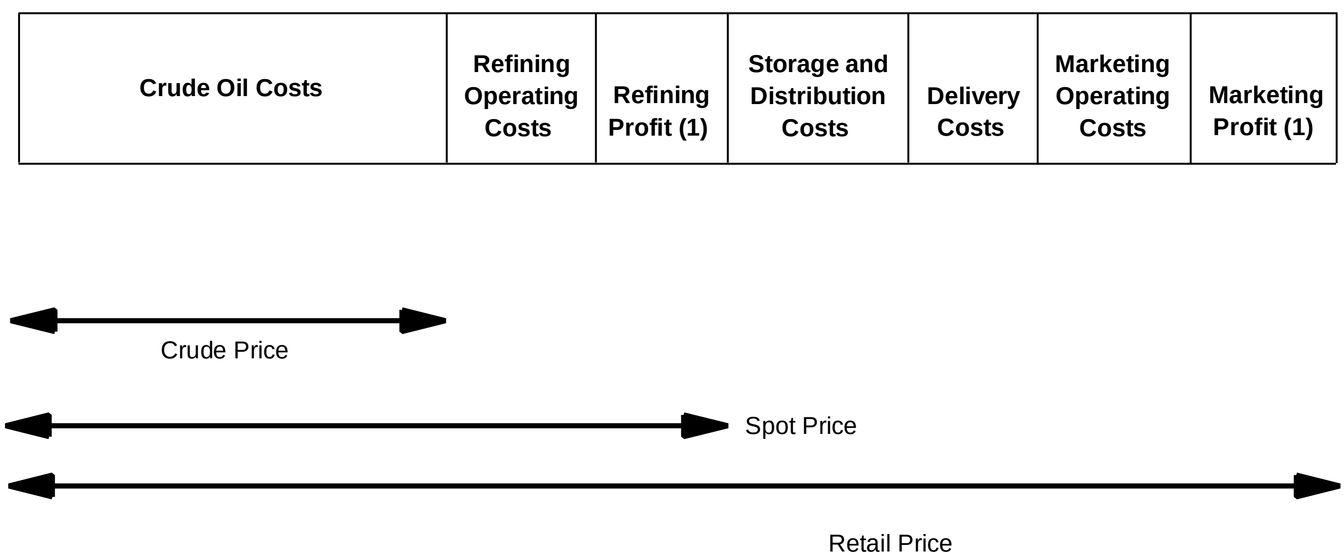
[7]Different data series (e.g., Platts versus Reuters) and different crude oils (e.g., Brent versus WTI) will produce different numbers, but the trend and conclusion remain the same. That is, crude oil and normal spread patterns explain most of the price increase. Other combinations of gasoline and crude oil prices were inspected and more in depth analyses were performed and discussed in *An Analysis of Gasoline Markets Spring 1996*, DOE/PO-0046 (June 1996).

Figure 13. U.S. Average Retail Regular Gasoline Price



Source: Energy Information Administration, *Annual Energy Review 1995* (January 1996), pp. 17, 161, and 179.

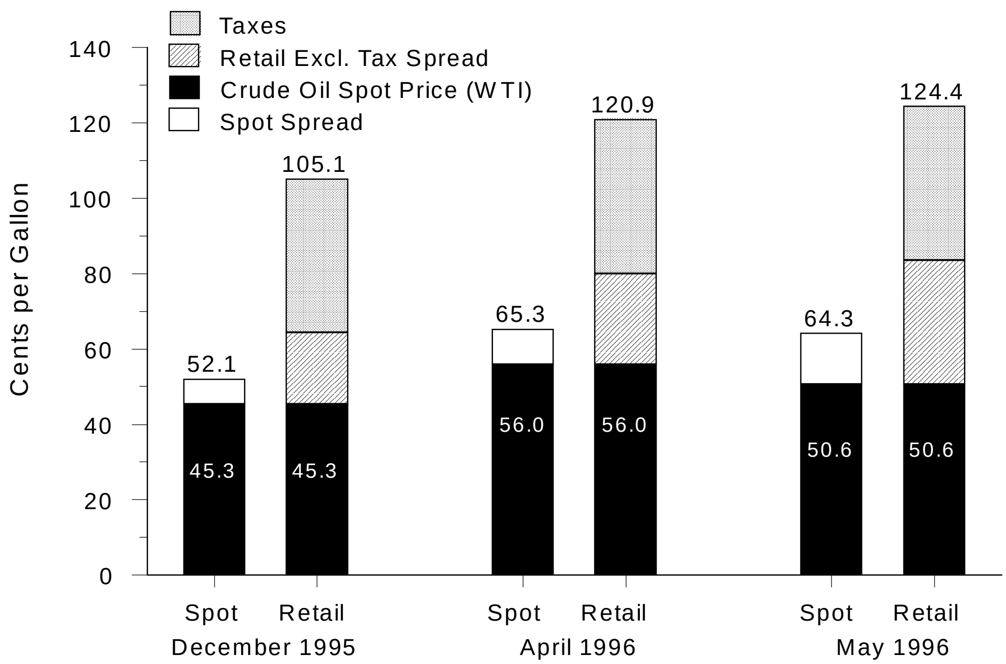
Figure 14. Price and Cost Relationships



(1) Profits may be positive or negative, based on market conditions.

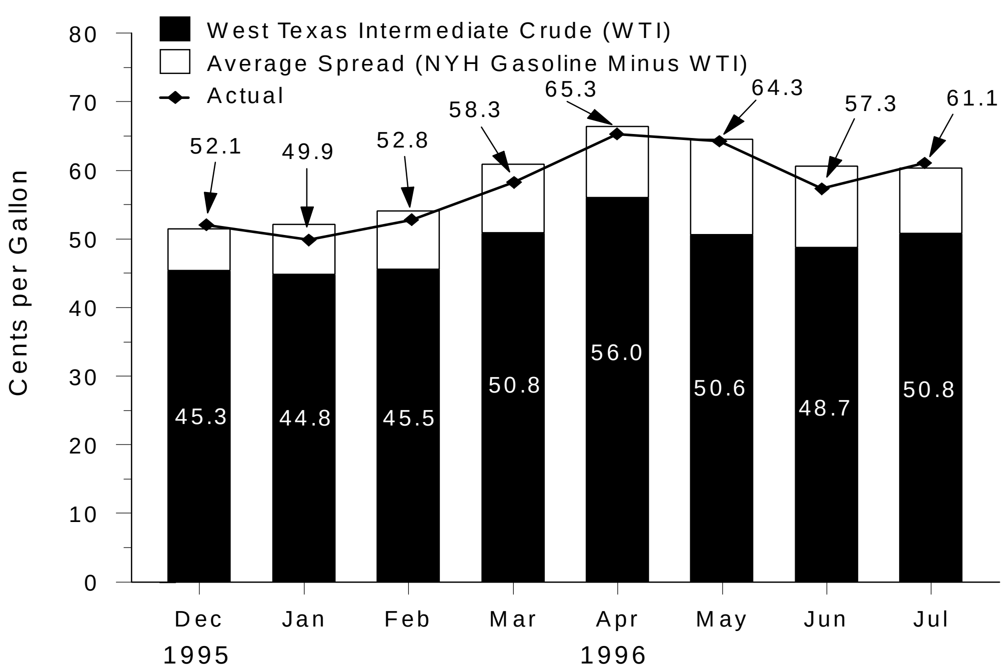
Source: Energy Information Administration.

Figure 15. Crude Oil and Gasoline Prices



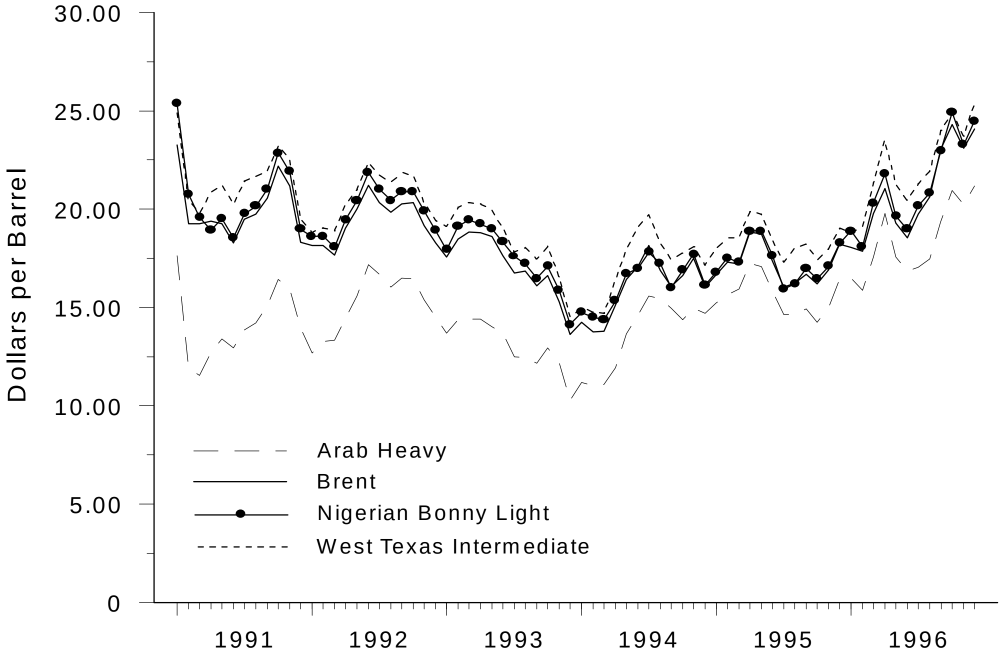
Note: Retail Excl. Tax Spread = retail price excluding taxes minus crude oil price. Spot Spread = spot price minus crude oil price.
Sources: **Spot Prices:** Standard & Poor's Platts. **Retail Prices:** Energy Information Administration (EIA), Form EIA-878, "Motor Gasoline Price Survey."

Figure 16. Gasoline Price Summary
(NY Harbor Spot Conventional Regular)



Source: Standard & Poor's Platts.

Figure 17. Monthly Average Spot Crude Prices



Source: Standard & Poor's Platts.

before starting to fall again. Although a similar increase in crude oil prices occurred in 1994, consumers were not as sensitive to the change because gasoline prices were very low at the start of the climb, and the increase occurred more gradually.

The rise in crude prices in the spring of 1996 can be attributed to a tight crude oil supply/demand balance in world markets. A tight petroleum balance occurs when demand exceeds production and when crude oil and product stocks are low, providing little cushion to meet unexpected demand surges or supply disruptions.

Importance of Supply/Demand Balance to Prices

As in all commodity markets, crude oil prices respond to the fundamental market forces underlying the crude oil supply/demand balance. For example, when little or no excess short-term supply exists to satisfy demand, markets tighten, producing upward pressure on prices.

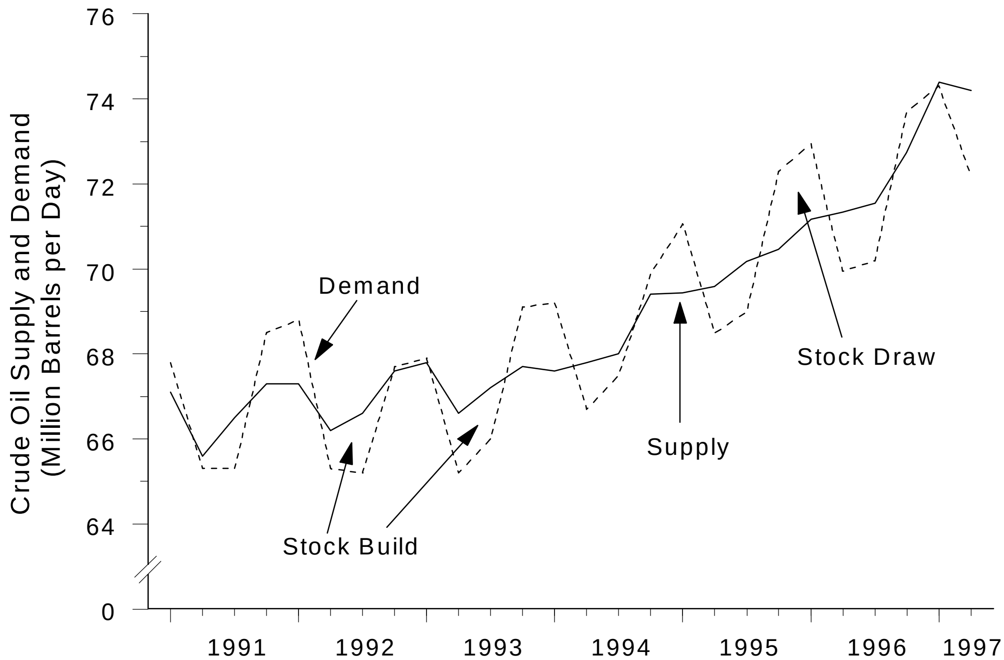
Stocks are a closely watched barometer of market balance — or tightness — for both product and crude oil markets. Changes in stocks reflect imbalances in production and demand and signal when supplies might be growing short or long relative to demand. When stocks are low relative to normal patterns and falling (i.e., demand is greater than production), market participants worry that production levels may be too low to meet future demand. When stocks are limited, increases in demand elevate buyers' concerns over supply availability, and cause them to bid higher prices in order to assure supply.

The Organization of Petroleum Exporting Countries (OPEC) plays an important role in the crude oil market's movement between tight and loose conditions. Non-OPEC producers generally produce at their maximum capability, but OPEC historically has members who produce at less than capacity to help maintain price levels. OPEC's success at controlling production when prices weaken has been limited. Demand for OPEC crude oil varies both as a function of world demand and non-OPEC supply. When the call on OPEC crude oil is high relative to OPEC capacity to produce, the market tends to support higher prices. When demand falls off, OPEC production does not always follow, creating downward pressure on prices due to oversupply.

Strong World Petroleum Demand Hit New Peaks in Winter 1995-96

An important factor in the spring crude price increase was expanding world demand. Figure 18 shows world petroleum supply and demand for 1991 through 1996. By the end of

Figure 18. World Supply and Demand



Sources: Energy Information Administration (EIA), *International Petroleum Statistics*. **First Quarter 1997:** Actual—*Oil Market Intelligence* (May 1997), Vol. II, No. 5, p. 3. **Second Quarter 1997:** Projected—*Oil Market Intelligence Update* (June 2, 1997), p.1.

1993, the global economy was recovering from the recession of the early 1990's. Demand began increasing and grew robustly in 1994 and 1995. Average daily consumption rates since 1993 have risen each year by about 1.6 million barrels per day (which represented 2 percent growth in 1995).

World petroleum demand is seasonal, peaking during winter in the northern hemisphere when world distillate needs are greatest. (This differs from the U.S., where demand peaks in summer because gasoline is the dominant product in the U.S. market.) In 1992 and 1993, excess supply caused petroleum stocks to build for two years in a row. Rising demand began to eat into this surplus in 1994 as stock draws exceeded stock builds for the year. As might be expected, crude oil prices dropped substantially during this time of over-supply, starting from about $22.37 monthly average (WTI) in June 1992 and bottoming out at an average $14.49 in December of 1993. The increases in demand in 1994 tightened the balance and brought prices up to an average of $19.70 in July 1994.

Demand was very high during the winter of 1995-96, exceeding most forecasts for the period prepared only months before. Actual demand in the first quarter 1996 exceeded the November International Energy Agency (IEA) forecast by 500 thousand barrels per day. The demand increase during winter 1995-96 over summer and over the prior winter was one of the highest during the last five years. The strength was attributed to an extended winter in the Atlantic Basin, continued strong Asian economic growth, and apparent stabilization of consumption in the former Soviet Union countries.

Winter 1995-96 Crude Supply Affected by Bad Weather

Demand growth alone cannot make a market tight. It is the balance between the supply and demand that determines the tightness or looseness of a market. Therefore, the explanation for increased tightness must include the inability or failure of crude oil supply to respond to demand growth.

World oil supply increased 1.5 million barrels per day during the winter of 1995-96, but fell short of predictions. Like demand, oil supply was also affected by weather. In early November 1995, the International Energy Agency predicted first quarter 1996 non-OPEC supply would be 43.9 million barrels per day. Actual supply was only 43.1 million barrels per day, or 800 thousand barrels per day short of expectations. Part of the shortfall was caused by bad weather conditions and operating problems in the North Sea and the Gulf of Mexico, areas located near markets (U.S. and Europe) where consumption was higher than expected.

While an 800 thousand barrels per day shortfall is less than 2 percent of world supply, it can put significant pressure on prices in a tight market, since the shortfall must be made up from stocks or increases in OPEC production. Stocks were low and OPEC was already producing at high levels. OPEC increased crude oil production from 25.4 million barrels per day fourth quarter 1995 to average 25.6 million barrels per day during the first four months of 1996. This was 1.1 million barrels per day over its self-imposed quota of 24.5 million barrels per day.

Tightening Winter World Petroleum Balance Set Stage for Spring Crude Runup

At the beginning of the 1995-96 winter, market analysts expected growing supply to more than offset strong demand growth. The world petroleum supply/demand balance as reflected in world stocks was not a concern. However, widespread, sustained winter weather served both to reduce some of the anticipated supply and to boost winter demand above expectations. Even with increased OPEC output over the winter, OECD countries experienced the largest decline in stocks over the fourth and first quarters in the last five years. Winter 1995-96 demand was up by 2.1 million barrels per day over winter 1994-95, while supply was up 1.5 million barrels per day. The OECD[8] winter 1995-96 stock draw was 1.1 million barrels per day compared to the 0.8 million barrels per day the prior winter. The 1.1 million barrels per day draw is large and significant in light of the low beginning stock levels. With low stocks and demand still outstripping supply, markets tightened. WTI prices rose from $17.44 in October to over $19 in December. Prices relaxed a bit in January, partially due to increased OPEC production.

Another factor was at work affecting market behavior. Throughout the winter, forecasters were predicting the arrival of significant new non-OPEC supply during the third and fourth quarters of 1996. Also, the low world demand season occurs in the second and third quarters. With prompt month (near-term) oil prices high due to scarce supply relative to demand, and the market expecting increasing supplies from non-OPEC (as well as from some OPEC) sources, future prices were expected to fall, as reflected in the futures markets. The situation where near-term prices are higher than future months' prices is called backwardation.

[8]The Organization for Economic Cooperation and Development is the international organization of the industrialized, market-economy countries. The following countries are members of OECD: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, Turkey, United Kingdom, Canada, United States, Mexico, Japan, Australia, New Zealand, and Korea.

The expectation of softening prices was further strengthened in late January, as the potential for Iraq returning to the market seemed to increase with the scheduling of the initial round of UN/Iraq discussions on limited oil sales for early February. Expectations of falling prices discouraged refiners from building or maintaining stocks despite high demands.

As winter proceeded, distillate demand grew, and stocks disappeared. Prices began climbing again in February and March. Backwardation in the futures market steepened to unusual levels as the prompt market tightened and the supply outlook still reflected expectations for new supplies in the short term (Figure 19).

The late cold spell in April affected Europe as well as the U.S., and sent the already-tight markets skyrocketing. Both regions were left with low crude and product stocks following the long winter, eliminating stocks as a supply source to meet the late surge in distillate demand. Refiners responded by increasing crude oil purchases and increasing refinery runs, which pushed the WTI price up over $25 per barrel.

Finally, in mid-April, as cold weather abated and demand for crude oil began to recede, prices began to weaken. WTI prices fell to about $21 per barrel by the end of the month and hovered around that price until the end of August.

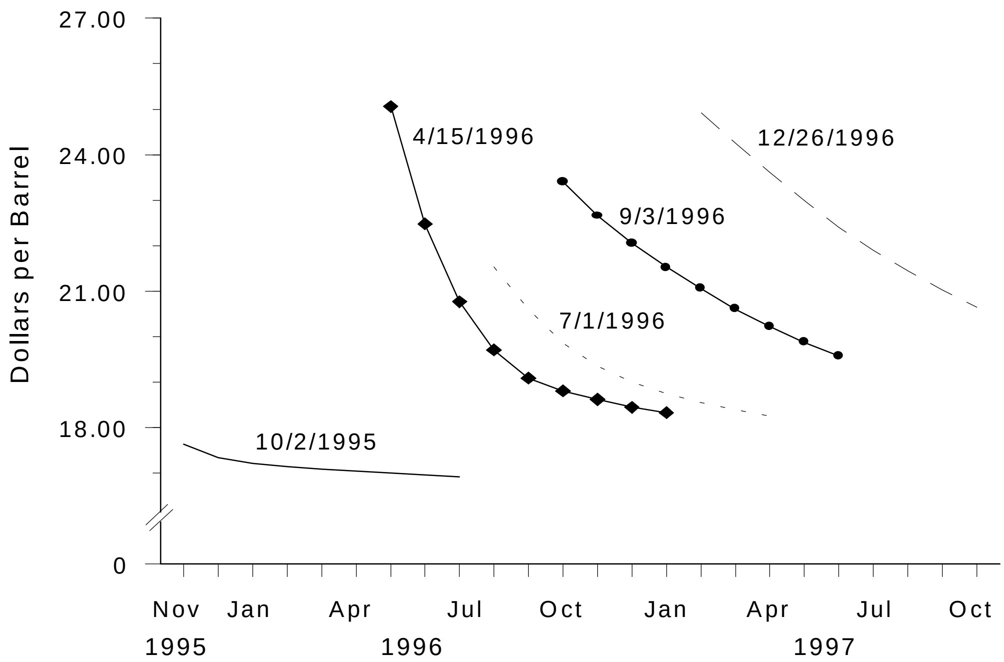
Normal Gasoline Markets

While crude oil price increases explained most of the gasoline price increase in spring 1996, the behavior of gasoline markets was responsible for the remainder. As background for discussion of the unusual gasoline market events of this past spring, a brief overview of normal market behavior is presented below. Two major characteristics of normal gasoline markets are particularly relevant: the relationship between spot and retail prices and the usual seasonal changes in the market.

Spot Spread is the Seasonal Component of Price

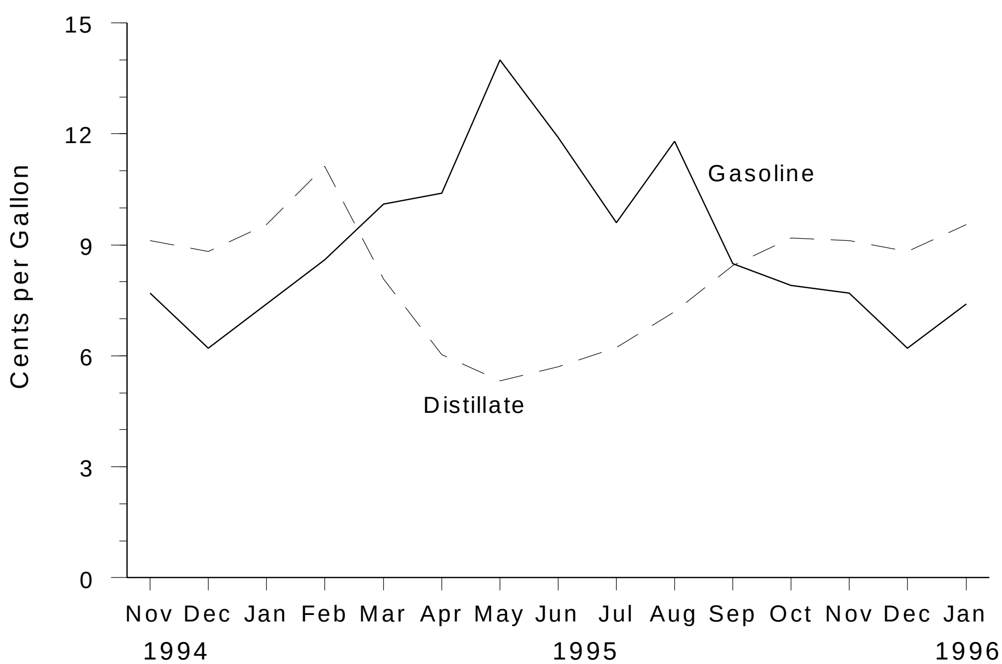
The effect of the gasoline market on prices is revealed in the spot spread (spot gasoline price minus crude price) and in the retail spread (retail price minus spot price). The gasoline spot spread gives an indication of the dollars being generated by refiners to cover their costs to process crude oil into gasoline and gasoline's contribution to refiners' taxes, financing costs, corporate overheads, and profits. Spot spreads tend to be low in winter and high in summer (Figure 20).

Figure 19. Changing Term Structure for Crude Oil Futures



Source: New York Mercantile Exchange.

Figure 20. The Seasonal Price Component (New York Harbor Spot 5-Year Average Spot Gasoline and Distillate Spreads)



Source: Energy Information Administration, data calculated using Standard & Poor's Platts.

Historically, spot spreads typically increase by 5 to 10 cents per gallon between their lows in December and their peaks in April and May. Although these spreads exhibit some regional variation, they follow a similar pattern throughout the U.S.

The seasonal pattern in gasoline spot spreads corresponds to the cyclical tightening and loosening of gasoline supply and demand. The gasoline supply and demand balance is, in turn, affected by the market for distillate (heating oil, diesel fuel and kerosene-jet fuel).

Price Seasonality Stems from Seasonality in Supply and Demand

Gasoline and distillate demands are highly seasonal, but counter-cyclical (Figure 21). Distillate demand peaks in the winter when heating oil requirements are highest, and gasoline peaks in the summer during the high driving season.

Refiners co-produce gasoline and distillate and have a limited ability to change the relative quantities being produced. Production of either product can be changed by shifting a small amount of material from the crude oil that is in a boiling range acceptable to either product, and also by changing operating conditions on process units downstream from the distillation tower. The limits of the changes require refiners to build and use stocks to meet seasonal peak demands (Figure 22).

Gasoline stocks build in the fall as distillate production is increased and gasoline co-production exceeds demand. Since the advent of clean fuels, gasoline stocks have experienced a slight drop in October as they are used to meet demand while refineries convert to winter gasoline fuel production. Gasoline stocks then continue their climb as production outstrips declining demand. Stocks usually peak in January when demand is at its lowest point. During the peak demand months of June, July, and August, stocks provide about 2 percent of demand. (Stocks play an even more important role in the distillate market, typically providing almost 12 percent of demand during the peak winter months of December, January and February).

In addition to domestic production, imports help meet U.S. gasoline demand. Some areas, such as Canada, Venezuela, and the U.S. Virgin Islands, provide the U.S. with gasoline imports on a regular basis. Europe and Saudi Arabia are examples of marginal suppliers, because their economics of selling product to the United States are not always attractive. Imports from marginal suppliers tend to increase during the second and third quarters as both demand and gasoline price spreads grow. However, import volumes can vary significantly from year to year. For example, second quarter 1995 imports averaged less than 350 thousand barrels per day after averaging 481 thousand barrels per day for the same period in 1994 (Figure 23).

Seasonal Supply/Demand Balance Impact on Gasoline and Crude Spread

In January, as gasoline production exceeds demand and stocks reach their peak, the oversupply of gasoline pushes the gasoline spreads to their lowest seasonal levels. During the first quarter, crude input to refineries declines and both gasoline and distillate production fall as refineries are shut down for routine, annual maintenance around March. Excess gasoline stocks accumulated over the fall and winter begin to decrease at this time. This pattern existed prior to environmental regulations requiring different summer and winter specifications. But now, there is even more need to draw down excess winter gasoline stocks, since winter gasoline does not meet summer gasoline specifications, and must be used before summer begins. Still, some extra gasoline stocks are required to meet peak summer demand.

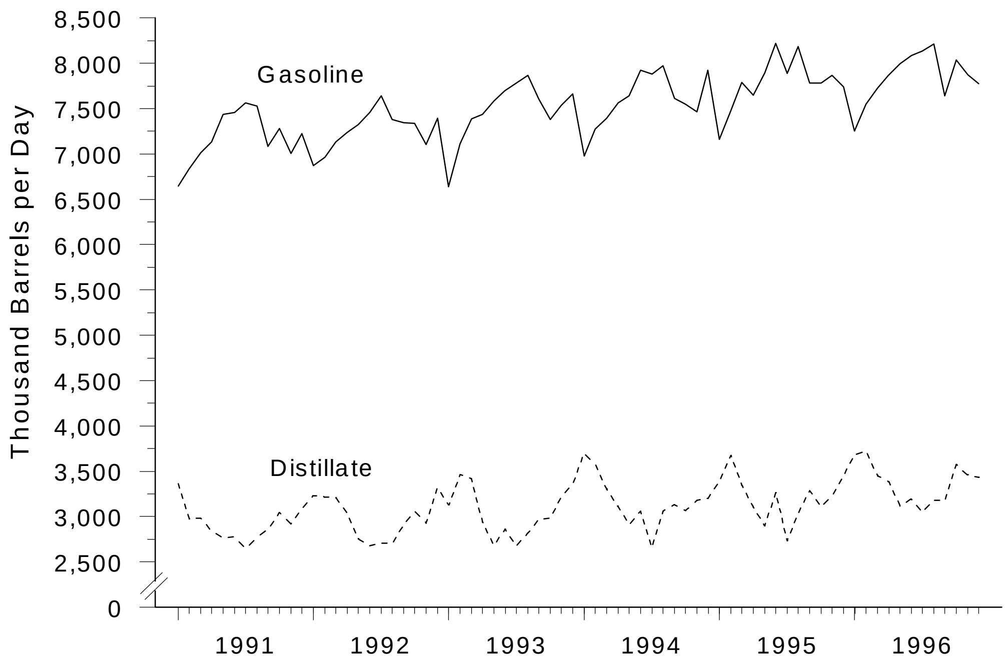
March and April are crucial months for both gasoline and distillate markets. At the end of March, following refinery maintenance, gasoline stock levels are assessed for their ability to help meet summer demand. At the same time, distillate stocks have been depleted by the end of the winter season. As a result, any extended-cold-weather distillate demand will have to be met through production, since stocks are close to minimum working levels and cannot provide additional supply.

By early April, gasoline demand begins to pick up. Gasoline stocks usually continue to fall because refiners are still coming back on stream, increasing imports lag behind the rising demand, and refiners and terminals are converting from winter to summer gasoline. With low stocks and increasing demand, buyers bid higher prices for product, thereby increasing spot spreads. These increasing spreads help to attract marginal imports. Sometime in late April or May, refiners return to full production, imports are strong, and the market is in better balance. Spreads frequently drop back, jumping again slightly in August before continuing their downward path to their December lows.

Prices Moving Through the System Show Lag Between Spot and Retail

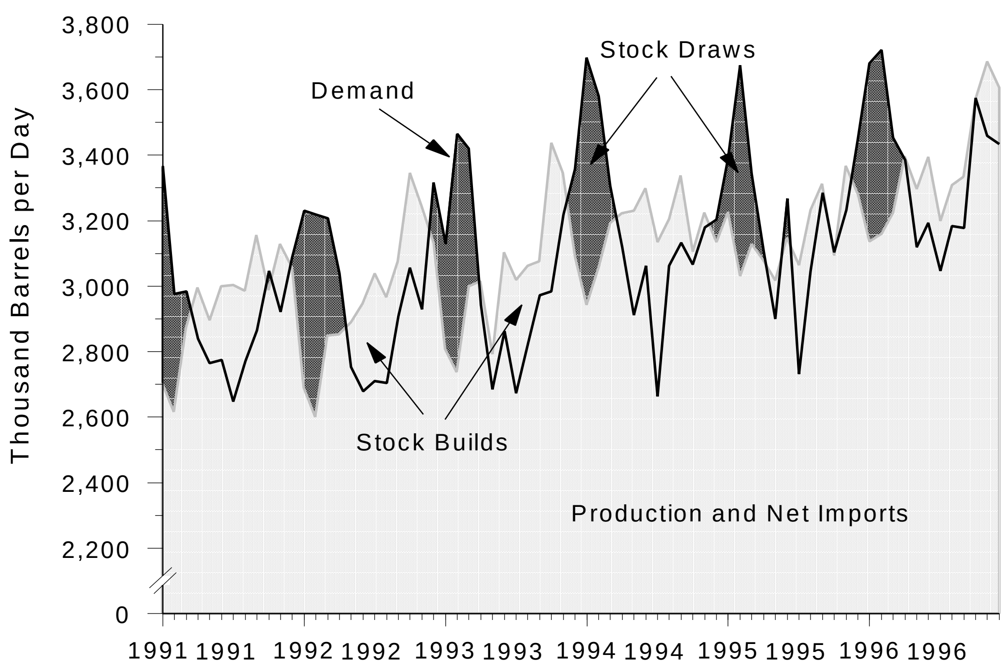
In addition to seasonality, the pace of price changes moving through the system from refineries to end users helps explain some of the timing of the 1996 spring gasoline price increase. Price changes move through the system at different

Figure 21. Gasoline and Distillate Counter-Cyclical Demand
(Thousand Barrels per Day)



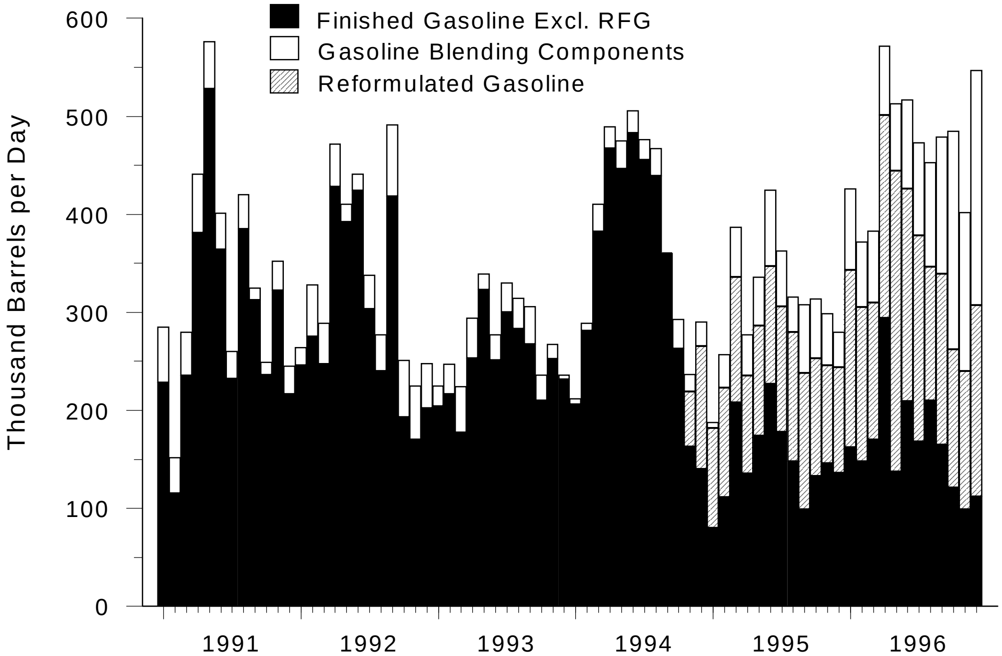
Sources: Energy Information Administration (EIA), **1991-1995:** *Petroleum Supply Annual*, Vol. 2, Table 2. **1996:** *Petroleum Supply Monthly* (various issues), Table 2.

Figure 22. Relying on Stocks to Meet Peak Demand: Distillate Supply and Demand



Sources: Energy Information Administration (EIA), **1991-1995:** *Petroleum Supply Annual*, Vol. 2, Table 2. **1996:** *Petroleum Supply Monthly* (various issues), Table 2.

Figure 23. Gasoline Imports



Sources: Energy Information Administration (EIA), **1991-1995:** *Petroleum Supply Annual*, Vol. 2, Table 2. **1996:** *Petroleum Supply Monthly* (various issues), Table 2.

rates. Spot gasoline prices, which change minute to minute, respond rapidly to crude oil price changes and reflect current perceptions of market tightness or looseness. Retail price changes, however, lag significantly behind spot price changes due both to competition and to the way in which the product works its way through the system to the consumer. This lag can be seen from the alignment of peaks in Figure 24. Activity and prices increase in wholesale markets in May in anticipation of the retail gasoline demand peak in June through August. When crude prices are stable, spot gasoline prices normally peak in May, while retail prices peak in June.

The retail price lag results in a price squeeze for retailers when wholesale prices are rising; however, the same lag keeps retail prices up while wholesale prices begin to fall.

Unusual Gasoline Market In First Quarter '96

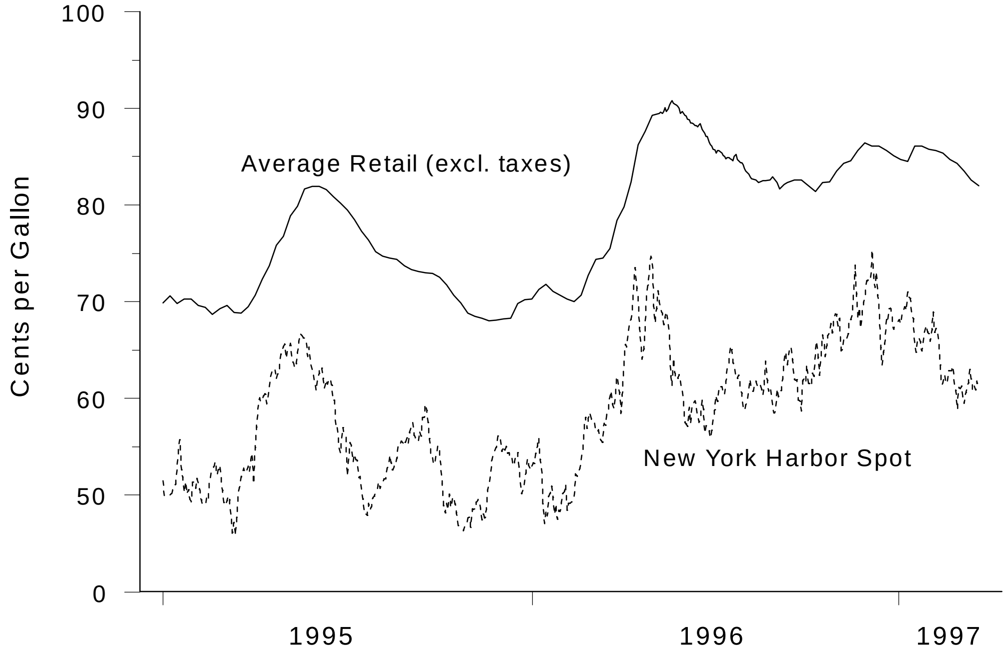
Gasoline markets during the first quarter of 1996 were unusual in several ways. While first quarter demand was strong, and both production and imports were fairly high, stocks were unusually low. During the first quarter, marginal demand is normally met by stocks. Fairly large stock draws can occur in March as refineries undergo scheduled maintenance and draw down winter specification gasoline. So low stocks can become a concern towards the end of March as the market assesses the industry's ability to meet peak summer demand.

Despite unusually low stocks throughout the first quarter 1996, gasoline spreads were weak for the time of year. Through March, the unusual increases in gasoline prices could be explained by crude oil price increases alone. The seasonal spread increases through March were below normal and added very little to spot gasoline price increases.

Gasoline Demand Growth Was Modest

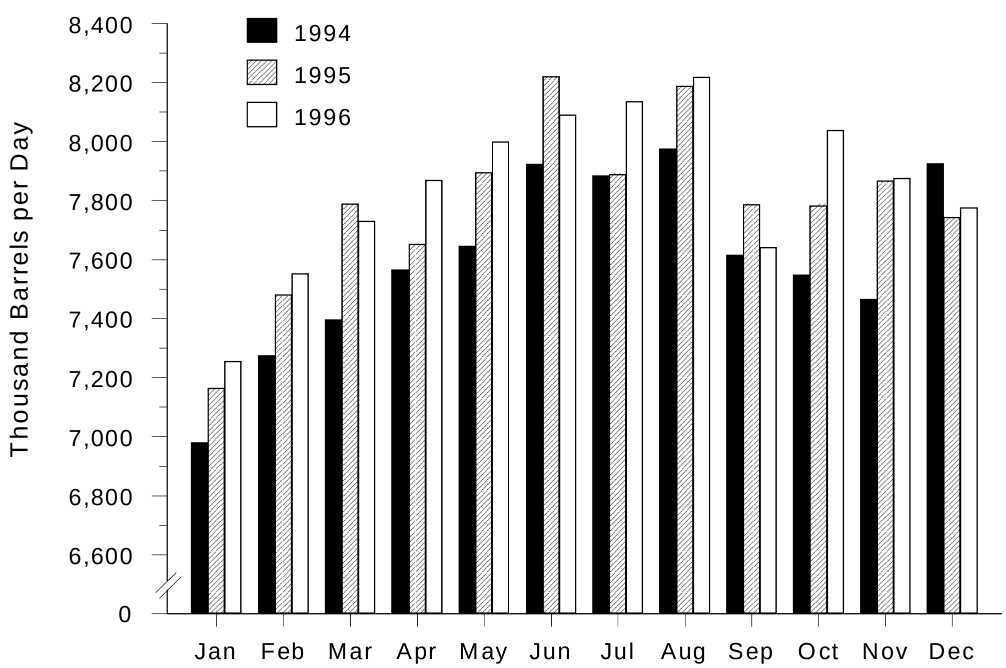
High gasoline demand is one of the factors that can contribute to upward pressure to prices. From 1992 through 1995, gasoline demand grew strongly, mainly because an increasing number of drivers and a stronger economy resulted in an increase in the total miles driven. Overall fleet efficiency (measured in miles per gallon) remained relatively flat. However, demand growth slowed in 1996. First quarter demand in 1996 was 7.5 million barrels per day, 0.4 percent higher than the high first quarter 1995 (Figure 25). Demand was higher than the previous year in both January and February, keeping a check on stock growth that normally occurs during this period. However, demand growth fell slightly in March compared to the previous year, which put

Figure 24. Spot and Retail Gasoline Prices (Excluding Taxes)



Sources: **Spot Prices:** Standard & Poor's Platts. **Retail Prices (Excluding Taxes):** Energy Information Administration (EIA), Form EIA-878, "Motor Gasoline Price Survey."

Figure 25. Gasoline Demand



Source: Energy Information Administration, *Petroleum Supply Monthly* (February 1997), Table S4.

less pressure than normal on the low stocks that help to meet demand in March.

Gasoline Production and Imports Were High

Since 1992, U.S. gasoline production has increased in conjunction with demand. Production increases are a result of higher refinery utilization, addition of oxygenates to produce reformulated gasoline (RFG), and some yield increase from process improvements. Since 1993, summer refinery distillation capacity utilization has averaged well over 90 percent.

Total gasoline production averaged 7.3 million barrels per day for first quarter 1996 (Figure 26), which was 54 thousand barrels per day over first quarter production in 1995. This production increase was only slightly higher than the gasoline demand increase of 34 thousand barrels per day for the same period. However, gasoline stocks were very low at the beginning of 1996, so production did little to improve the stock levels through the first quarter.[9]

High gasoline imports supplemented production in 1996 (see Figure 23 and box, p. 39). These imports prevented stocks from dropping as much as they normally would have dropped during the first quarter.

Gasoline Stocks Remained Low But Spreads Were Weak

Gasoline stocks started to drop below the historical seasonal range beginning in August 1995 and fell even further below this range over the winter. Gasoline stocks have exhibited a long term downward trend, partially due to companies managing inventories more efficiently (see Chapter 5). But stocks were lower in winter 1995-96 than even the long-term downward trend might have predicted[10] (Figure 27). Gasoline stock draws in spring 1996 were smaller than normal, mainly because of high imports, but stock levels remained below the average seasonal range through March.

Low gasoline stocks do not usually generate much price pressure over the winter months when supply is in excess of demand. Through March, gasoline price spreads remained weak, indicating little market concern with supply. A combination of low spreads, prospects for continued high imports, and expectations of falling crude oil feedstock cost discouraged refiners and wholesale buyers from holding any more stocks than necessary. Furthermore, winter-specification gasoline cannot be used during the summer and so must be drawn down before building summer gasoline stocks. This situation changed in April.

The April Runup: Distillate and Gasoline Markets Clash

In April 1996, crude prices jumped considerably and, simultaneously, gasoline markets tightened more than expected. This drove the gasoline spread to, or above, normal levels in different parts of the country on top of the crude price increases. The following factors set the stage for the April runup:

- Crude prices had been strengthening prior to April due to low stocks and continued strong demand, which drove buyers to purchase crude oil as they waited for prices to weaken in the future.

- April began with lower than normal gasoline stocks, but gasoline spreads were a little weak in expectation that high imports and domestic production would satisfy the upcoming summer demand.

- Futures markets reflected expectations that the gasoline market would tighten as usual in April as demand increased towards its normal June-August peak season, but would decline in subsequent months, in response to declining crude prices. Expectations that prices would fall discouraged gasoline wholesalers from holding any more stocks than necessary.

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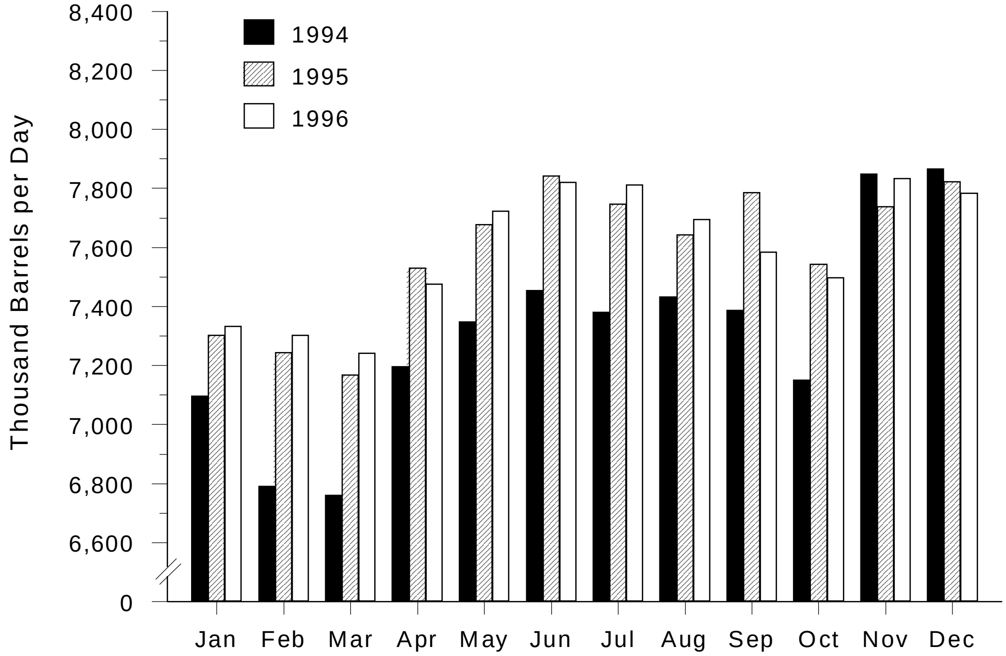
[9]The shutdown and sale of the BP Marcus Hook refinery to Tosco in January was observed to have little impact on availability of fuel supplies to the Northeast. From the Bayway, New Jersey refinery, Tosco was able to supply the needs of the BP retail marketing assets acquired. Marcus Hook was a merchant refinery (i.e., sold most of its products to other companies) and buyers of its products had ample time to arrange for other supply sources, since possible shutdown had been a matter of public speculation for months. Despite relatively high utilization rates of U.S. refineries, there was still the capability to deal with the loss of capacity the size of the Marcus Hook refinery in the Northeast. Had the refinery been in operation, its production may have replaced some Gulf Coast production and some imports.

[10]The weak gasoline build that occurred in the fall and winter 1996 was mainly due to the combined effects of cold weather and expectations of falling prices (backwardation). The crude oil price backwardation transferred to the product markets, resulting in gasoline buyers expecting gasoline prices to fall in conjunction with crude oil price declines several months in the future. (For more discussion, see, *An Analysis of Gasoline Markets Spring 1996*, DOE/PO-0046 (June 1996).)

Figure 26. Gasoline Production



Source: Energy Information Administration, *Petroleum Supply Monthly* (February 1997), Table S4.

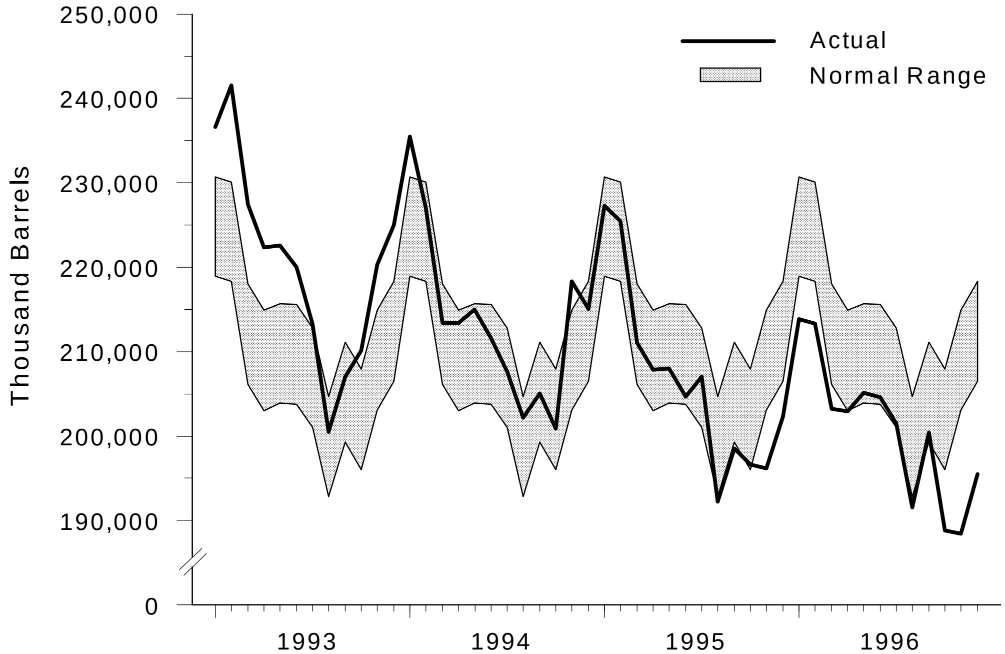
Gasoline Imports Were Expected to Be High in 1996, Due to Several Factors

- Europe was experiencing excess gasoline production as European refiners produced distillate products for their own markets. European refiners have been adding fluid catalytic cracking units to increase gasoline and distillate production, but they are producing too much gasoline versus distillate relative to regional demand. This provided a ready source of gasoline that flowed to the United States in 1996 when price differences between Europe and the United States exceeded transportation costs (approximately 5 cents per gallon).

- The tight U.S. gasoline market (high demand and capacity utilization with low stocks) pushed prices up relative to Europe. Although Europe was affected by higher crude prices, it did not experience tight seasonal gasoline markets affecting the spread between gasoline and crude oil prices.

- Asia has been a primary market for Saudi exports of refined products; however, Asian refining capacity has expanded rapidly, decreasing its product import needs. As a result, Saudi Arabia, a marginal supplier of product to the United States during the summer, was expected potentially to have extra product to sell here.

Figure 27. Total Motor Gasoline Stocks (End of Month)



Sources: Energy Information Administration (EIA), **1993-1995:** *Petroleum Supply Annual*, Vol. 2, Table 2. **1996:** *Petroleum Supply Monthly* (various issues), Table 2.

When the late cold spell hit the Atlantic Basin, the distillate market unexpectedly clashed with the gasoline market. The cold weather created extra demand for distillate on both sides of the Atlantic at a time when this demand is usually bottoming out (Figure 28) and distillate stocks are at their seasonal low point (Figure 29). As distillate stocks were unusually low in 1996 following the long winter[11], the unexpected April demand had to be met through increased production (Figure 30). Thus, refiners refocused on distillate production at a time when they normally would be maximizing gasoline output (Figures 25 and 26).

Low gasoline stocks combined with refiners focusing unusually on producing distillate in April to meet demand from the late cold spell added pressure to the gasoline markets. The New York Harbor spot gasoline spread, which had been running below normal (Figure 31), suddenly jumped from 2.6 cents below average in March to 1 cent below in April. By May, the actual New York Harbor spread was at its normal level. Given the spread's low starting point in February and March, about 2 cents of the increase could be attributed to the tight market.[12]

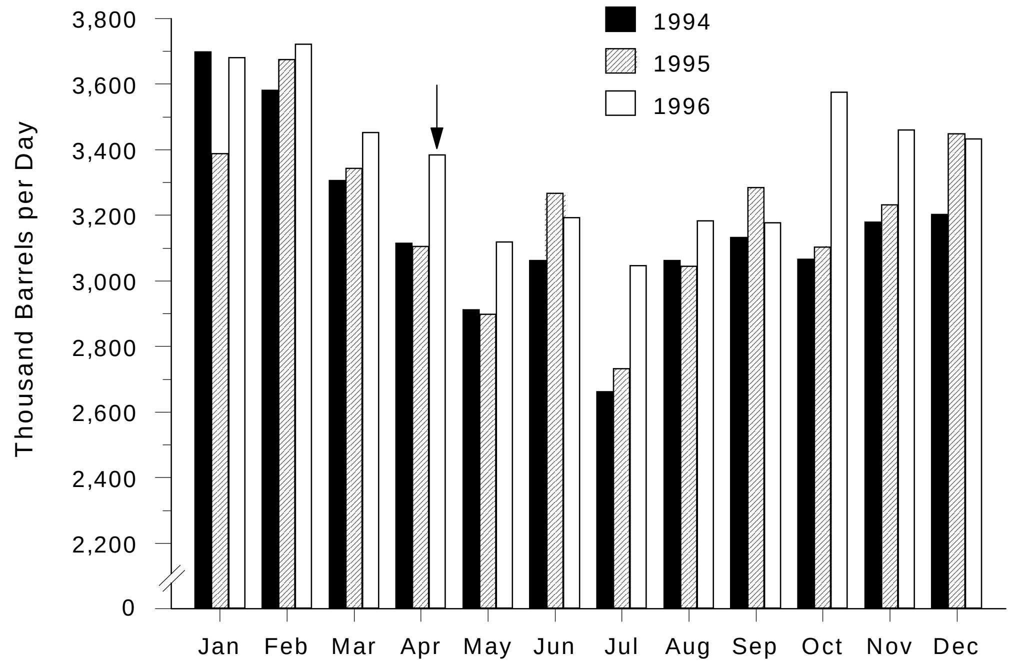
Spot gasoline prices rose with increasing crude oil prices and increasing spreads, peaking in April along with crude oil prices. These increases eventually made their way to the retail market. As retail markets lag behind spot markets, retail regular conventional prices peaked at almost $1.29 on May 17, after the April spot price peak. Crude oil price increases accounted for about 10.7 cents of the 13.2 cent per gallon increase in New York Harbor spot prices from December 1995 to April 1996. The normal seasonal increase in gasoline prices accounted for most of the remainder, with perhaps 2 cents per gallon being attributable to unusual tightness of gasoline markets since spreads had been running low at the beginning of the year, but climbed rapidly to average levels.

The increase in gasoline prices during the spring of 1996 was more pronounced in some regions of the country. The box on p. 43 discusses the unusual circumstances in gasoline markets in California.

[11]Distillate demand was up 4.3 percent in the first quarter over 1995 due to continued cold weather. In spite of the increase in distillate production, distillate fuel stock draw from the end of October through March was 13 percent above normal (as measured by the normal stock range published in the EIA's *Weekly Petroleum Status Report*).

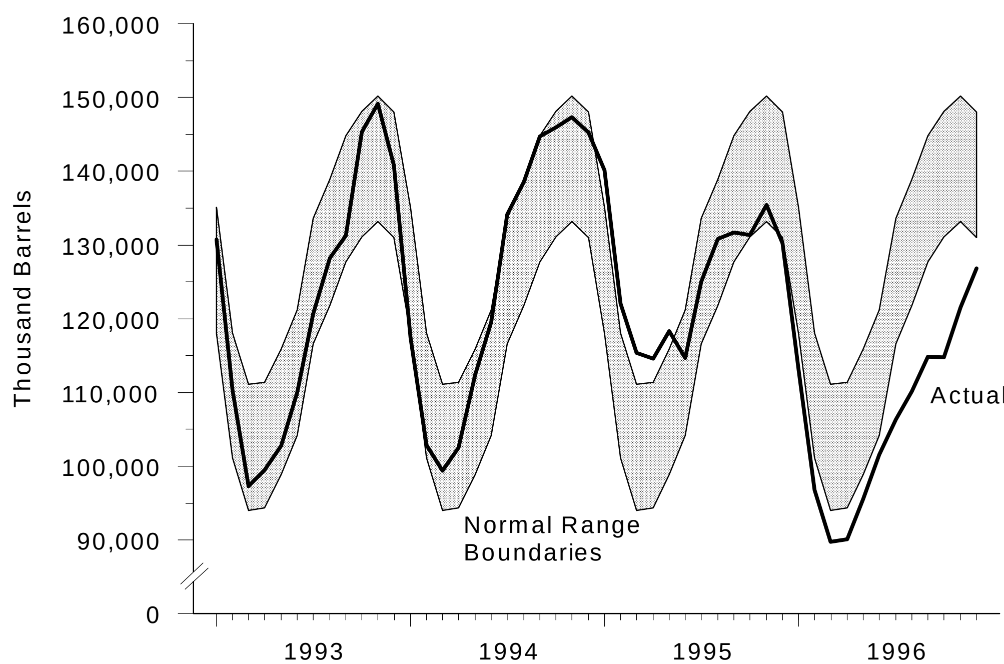
[12]This graphical New York Harbor and WTI display is supported by a more in-depth regression analysis using average resale gasoline prices and refiners' acquisition cost of crude oil. This is discussed in *An Analysis of Gasoline Markets Spring 1996*, DOE/PO-0046 (June 1996).

Figure 28. Distillate Demand



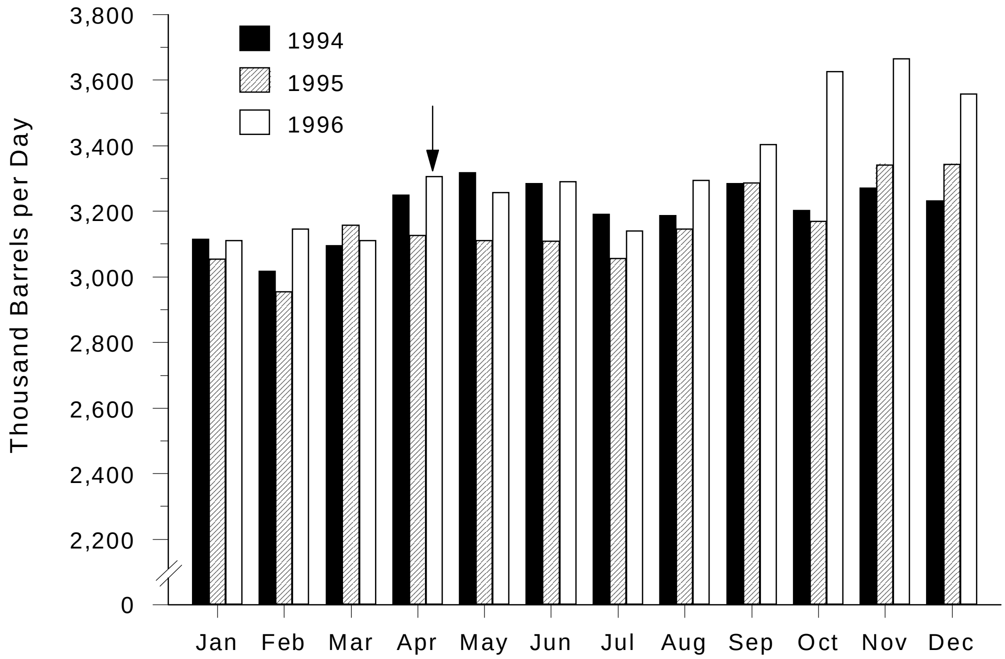
Source: Energy Information Administration, *Petroleum Supply Monthly* (February 1997), Table S5.

Figure 29. Distillate Stocks (End of Month)



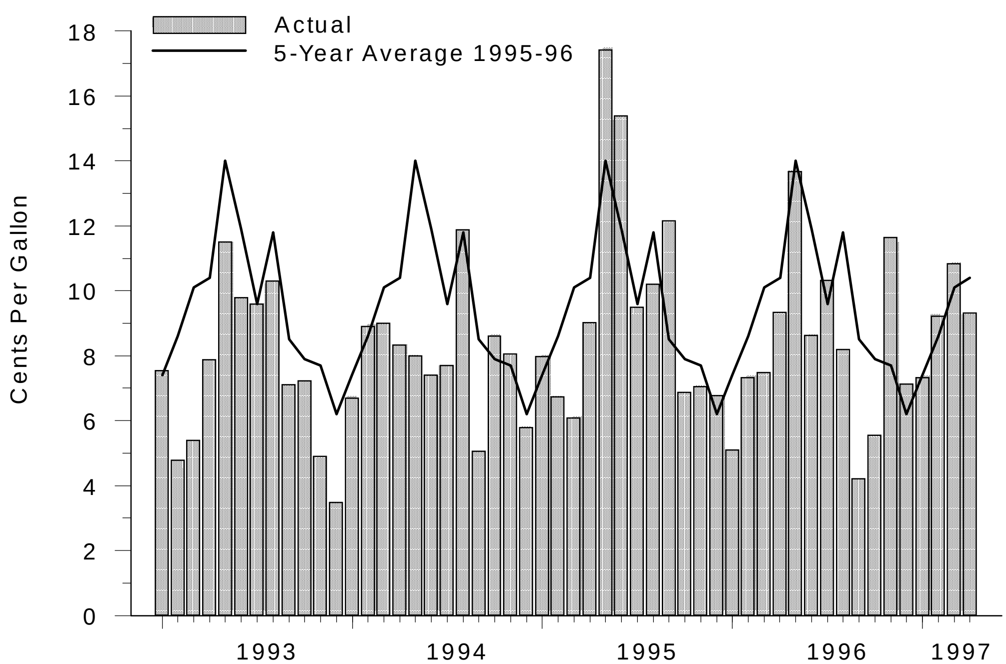
Sources: Energy Information Administration (EIA), **1993-1995:** *Petroleum Supply Annual*, Vol. 2, Table 2. **1996:** *Petroleum Supply Monthly* (various issues), Table 2.

Figure 30. Distillate Production



Source: Energy Information Administration, *Petroleum Supply Monthly* (February 1997), Table S5.

Figure 31. Gasoline Spot Spreads
(NY Harbor Spot Conventional - WTI)



Source: Standard & Poor's Platts.

A Special Case: California

California introduced its own new and unique Phase 2 reformulated gasoline (CaRFG) during the spring of 1996. CaRFG has more stringent requirements than Federal RFG, making it more difficult and more expensive to produce than Federal RFG. The California Energy Commission estimates the additional cost to produce CaRFG at between 5 and 15 cents more per gallon. Although the higher costs translate to higher prices, consumers will benefit from significant smog reduction.

Average CaRFG demand was projected at 896 thousand barrels per day for the first year (March 1, 1996 through February 28, 1997), taking into consideration the fuel efficiency loss (about 1-2 percent lower than Federal RFG). Average production was projected 906 thousand barrels per day, providing a 10 thousand barrels per day cushion. While not large, this cushion was expected to be adequate.* Some supply potential exists outside of California. However, most refiners are not equipped to produce the new fuel in any large amounts, if at all. Refineries in California are expected to use 85-90 percent of their gasoline capacity to produce the new fuel.

Unfortunately, supply problems developed as a number of California refineries experienced operating problems and had to shutdown for repairs. Spot prices shot up, driven by uncertainties around potential shortages. Unlike the rest of the country, the supply problems in California affected spreads strongly. Conventional gasoline prices were also affected by the supply problems, since California refiners also serve neighboring states.

The price increase experienced in California in 1996 reflected a market stress situation, illustrating price response when supply disruptions occur in a very tight market. With little or no immediate supply alternatives, the loss of expected supply resulted in the market bidding prices up at panic rates. Consumers paid an average of $1.15 per gallon for regular gasoline in December 1995. By April 1996, the average was $1.40, or 25 cents per gallon higher due to crude price increases, the changeover to CaRFG, and the refinery operating difficulties.

*California Air Resources Board and California Energy Commission's February 1996 Supply/Demand Analysis.

Gasoline Price Progress Through Summer 1996

As expected, crude oil prices fell during April after the cold weather abated, distillate demand relaxed, and the short-term demand for crude oil subsided. The decline of WTI prices ended in June, when it began hovering around $21 per barrel, down from its peak of over $25 per barrel in April. The $4 per barrel decline is equivalent to about 9.5 cents per gallon. Weekly average spot gasoline prices declined over 13 cents per gallon during this time. Crude oil prices began to show renewed vigor in August and continued to climb through September, as Northern Hemisphere demand began to increase in preparation for winter heating fuel needs, putting upward pressure on all petroleum product prices.

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Gasoline stocks, which began the year low, had risen to very near the normal seasonal range in May, and stayed at the low end of the normal range through September, the end of the summer driving season. Imports of gasoline and blending components in 1996 were very high, as had been expected, averaging 355 thousand barrels per day compared to 202 in 1995 and 274 in 1994, which was another year with high imports.

Gasoline price spreads reflected the gasoline supply/demand balance. They stayed below the 5-year average spreads with the exception of July, when preliminary data indicated stronger than normal demand with falling stocks. Since stocks were still at low levels, the market reacted quickly to the unexpected tightening by pushing prices higher. Still gasoline spreads in July only exceeded the 5-year average by 0.7 cents per gallon. The supply/demand balance adjusted and spreads fell well below normal in August and September, although gasoline price rose along with crude oil price.

Monthly average spot prices fell from their peak of 65.3 cents per gallon in April to bottom out in June at 57.3 cents. Prices then began to rise as crude oil prices strengthened, countering declining spreads. By September, the end of the traditional driving season, New York Harbor spot prices had increased by 4 cents per gallon over the June price, and Gulf Coast spot prices were up 2.4 cents per gallon. Retail conventional regular gasoline fell from its monthly average peak of $1.24 in May to $1.18 in August. But retail prices began to increase in September with the underlying increase in crude oil price. By year end, retail prices had returned to levels seen the prior spring.

Gasoline Markets Affected Distillate

In spring 1996, distillate markets affected the normal behavior of gasoline markets. But strong gasoline imports affected distillate markets as the year progressed. Greater reliance on gasoline imports to meet gasoline demand resulted in changed gasoline and distillate production and stocking patterns in the United States. Figure 28 shows that 1996 distillate stocks have been low since the draw down during the winter of 1995-96. Although distillate stock levels were low as summer 1996 began, they increased normally in May and June. But in July, which is normally the peak re-build month, historically averaging over 11 million barrels increase, stocks only increased 2.4 million barrels.

Since part of gasoline supply in 1996 was being met from higher imports rather than increased refinery runs, refiners increased the yields of kerosene jet fuel and distillate (heating fuel and diesel) to adjust to the new balance between refinery production and demand. But the yield increase of distillate was not uniform throughout the year. In the first quarter, the yield increase provided 27 thousand barrels per day more heating fuel and diesel than in 1995; in the second and third quarters, the higher yield produced 115 thousand barrels per day more distillate; and in the fourth quarter, when distillate stocks were very low, the volume increase from higher yields was to 226 thousand barrels per day. The distillate volume in the fourth quarter versus the second and third quarters was achieved by changing the yield split between kerosene jet fuel and distillate and by increasing crude runs. The uneven increase in distillate yields over the year did not provide enough distillate production to build stocks to normal levels over the summer, but the extra jump in yield and increased crude throughput during the fourth quarter allowed production to meet distillate demand without as much stock draw as might normally have occurred.

The affect of gasoline imports on distillate stocks was only one of several factors contributing to the low distillate stock situation in 1996. Other factors included:[13]

- Distillate stocks began the year low.

- Continued backwardation in crude oil markets caused suppliers to expect distillate prices to fall in the out months. This discouraged suppliers from building stocks because they could not lock in a profit on stocks being held, and might even have to sell stocked product at a loss.

- Unusually high demand for distillate occurred in July, which detracted from the strong build in stocks that normally occurs in this month.

In spite of increased crude runs during the fourth quarter, the increased distillate yields lowered gasoline production from crude oil over that produced from crude oil fourth quarter 1995. Only by increasing inputs of imported blending components was refinery gasoline production brought back to levels similar to those in 1995. Finished gasoline imports also added to supply, but gasoline stocks dropped much lower than normal in October and declined even further in November when they traditionally increase. December and January builds in stocks were more typical, but by this time, gasoline stocks were running well below normal levels.

Price Reversal in Spring 1997

The petroleum markets in spring 1997 completed the story of the spring 1996 runup with a price reversal, providing an excellent opportunity to watch the dynamics described in this chapter work when crude market factors moved in the opposite direction. Table 1 summarizes some major market factors for comparison. (The following box on p. 46 presents a discussion of whether the crude price increase in the spring of 1996 heralds increased volatility in the future.)

In qualitative terms, the supply/demand balance for gasoline in spring 1997 was almost the same as in spring 1996: demand growth was low to modest; levels of gasoline production from January through April supplied about 96 percent of demand in both years; imports were very high in 1996 and even higher in 1997; and stocks were low. Prices, on the other hand, behaved very differently. Prices rose dramatically during spring 1996, but fell during spring 1997, even though gasoline spot price spreads were slightly higher in 1997 (Figures 31 through 34).

The explanation of the spring 1997 price decline lies mainly with crude oil prices and normal seasonal spread changes — the main factors behind the spring 1996 price increase. WTI crude oil prices in April averaged 9 cents lower than in April 1996. New York Harbor spot gasoline prices also averaged 9 cents lower in April 1997 than in April 1996. From December 1996 through April 1997, crude oil prices fell 13.5 cents per gallon, and spot gasoline prices fell 11.3 cents as the impact from declining crudes price was moderated by normal increases in seasonal spreads.

[13]Energy Information Administration (EIA), "Distillate Fuel Oil Assessment for Winter 1996-1997," *Petroleum Supply Monthly*, DOE/EIA-0109(96/11) (Washington, DC, November 1996), pp. xv-xxiii.

Table 1. Spring 1997 and Spring 1996 Summary Market Comparison

Market Factor	January-April 1996	January-April 1997
World Petroleum Supply/ Demand Balance	Winter stock draw was high.	Winter stock draw was low.
	Strong world economy supported petroleum demand.	Strong world economy supported petroleum demand.
	Cold weather increased winter demand more than expected (3 percent higher than in winter 1994-95).	Winter demand was held in check by milder weather (1.8 percent higher than in winter 1995-96).
	Supply growth was less than expected.	Supply growth was strong.
Crude Supply	Iraqi entry into market was delayed.	Iraq began sales in December '96.
	Non-OPEC additions were expected, but did not arrive.	Non-OPEC supply increased, and more was expected.
	Light crude was abundant.	Abundance of light crude grew.
Crude Markets	Prices began 1996 under $20.00 per barrel.	Prices began 1997 about $26.00 per barrel after high demand fourth quarter.
	Tight: Prices rose February thru April with cold weather and lack of expected supplies.	Weakening: Prices fell January through April with strong supplies relative to demand.
	Futures market backwardation was steep.	Term structure of crude futures flattened.
	Light-heavy price differentials were modest.	Light-heavy price differentials were very small.
U.S. Winter Distillate	Winter began with stocks normal, but ended March with stocks lower than normal due to cold weather.	Winter began with stocks low. Demand was met through extra production, and winter ended with stocks at normal levels due to mild weather.
	April: With little or no discretionary stocks, late cold weather caused refiners to re-focus on distillate production.	April: Although demand was strong, no unexpected re-focusing on distillate production occurred.
U.S. Gasoline Supply/Demand Balance	Stocks were low.	Stocks were very low.
	Demand growth was modest (1.1 percent).	Demand growth was low to modest (0.8 percent).
	Demand level was high (7,601 thousand barrels per day).	Demand level was high (7,710 thousand barrels per day).
	Production growth was modest.	Production growth was modest.
	Imports were high (meeting 5.8 percent of demand).	Imports were very high (meeting 7.6 percent of demand).
Gasoline Market	Increasing crude oil prices pushed gasoline prices up.	Falling crude oil prices brought gasoline prices down.
	Spreads were mainly at or below seasonal norms.	Spreads were slightly above seasonal norms.

Source: Energy Information Administration.

Was the Spring Crude Price Increase a Sign of Future Increased Volatility?

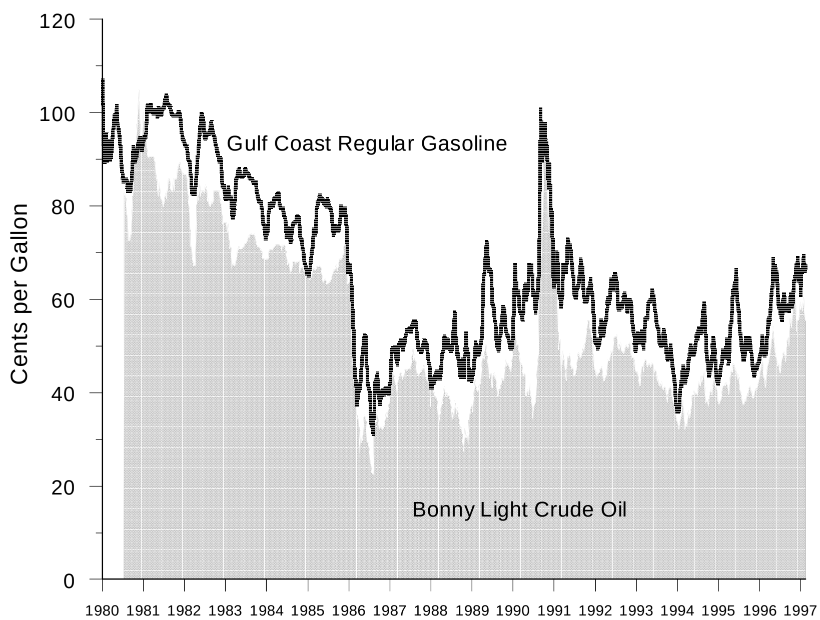
Is the situation experienced in Spring 1996 just another sign of growing price volatility, and will we see more of the same in the future? In short, the crude market supply/demand balance was fairly tight in 1996, which creates an environment for exaggerated price swings. Demand was high, excess production capacity was not available, and world petroleum stocks were lower than average. When unexpected events occur in tight markets, such as the late winter cold snap in 1996, that affect the perceived availability of crude oil, buyers are more likely to over-react, creating large price swings.

In spring 1996, a number of unusual factors acted simultaneously to increase buyers concern over crude availability, including unusual late cold weather and expectations for large price declines in the near future, which encouraged keeping low stocks. While these specific triggers may not occur again to drive prices up temporarily, other factors can create the same effect during a tight market. As discussed in this chapter, the transition time between the end of winter, when world crude and product stocks are low, and the beginning of the U.S. high gasoline demand season is a vulnerable period. Events during that crucial time period can have a large influence on the market.

In the short-term, crude inventories began to recover worldwide over the winter. World petroleum demand only increased 1.4 million barrels per day over winter 1995-96, while supply increased 2.3 million barrels per day (preliminary estimates). Crude oil prices averaged $25.41 per barrel in December, but began falling in January. By April, WTI averaged $19.75. Although the crude market is loosening, world petroleum stocks do not seem to be in excess, so there is still some potential for price increases. As new supply grows, the probability of sharp price movements will diminish, since buyers will perceive higher crude availability, and thus no need to bid prices higher to assure supply when unexpected events occur.

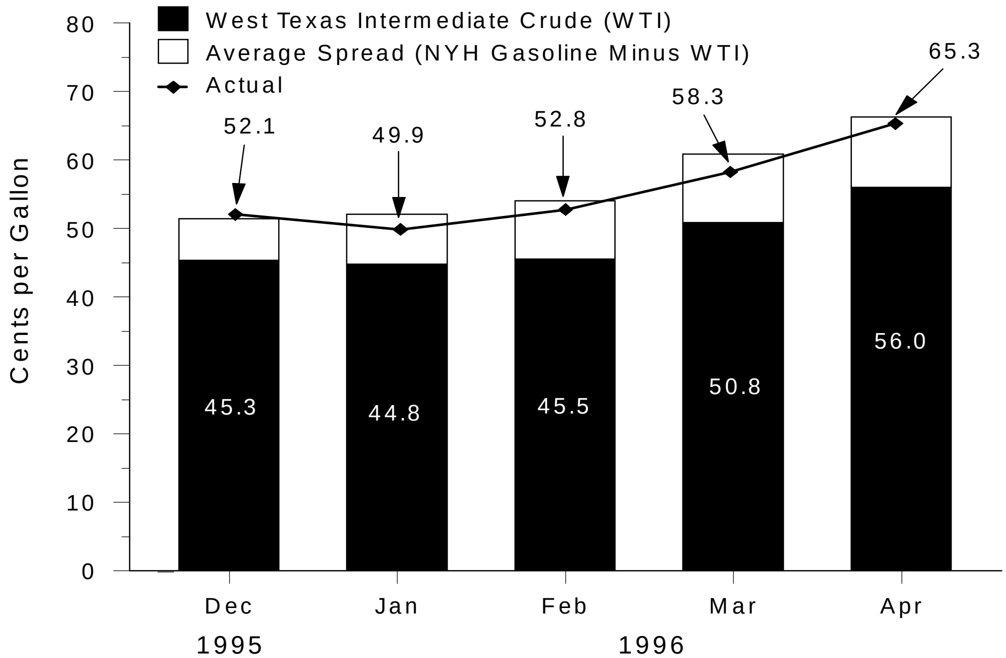
When viewed over the long term (see figure), crude prices were strong in 1996, but not especially more volatile than many other times in history. The short-term price swing that occurred last spring was a little sharper and higher than most swings seen in Figure 14, but was not dramatically out of line with past price variations. It occurred at a time that was very visible to consumers — just when gasoline prices normally increase, and the market had not seen the magnitude of such swings for several years.

Weekly Average Spot Prices



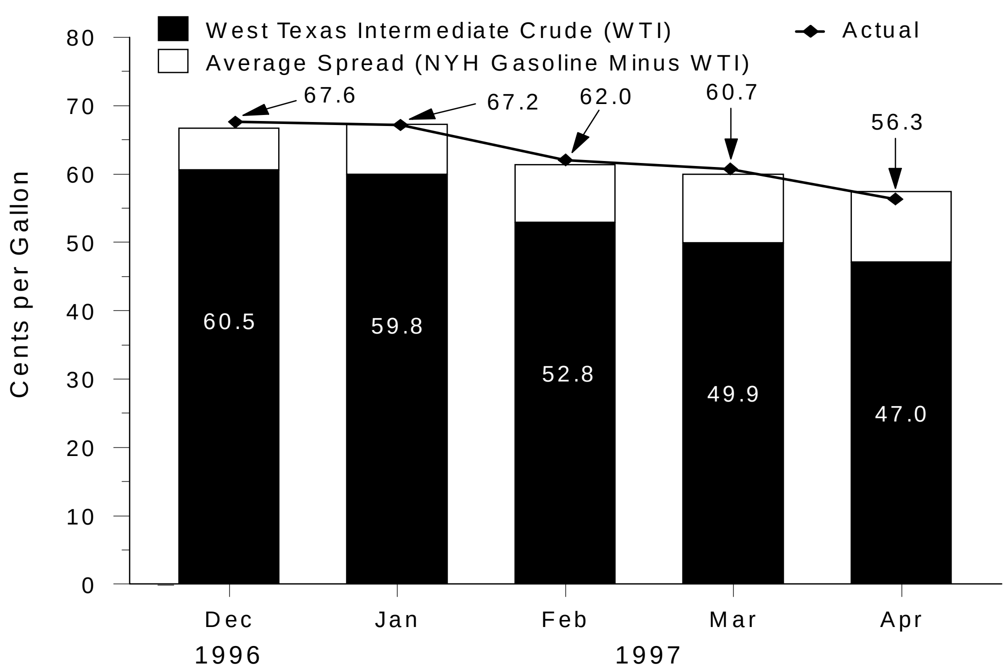
Source: Standard & Poor's Platts.

Figure 32. Spring 1996 Gasoline Price Summary
(NY Harbor Spot Conventional Regular)



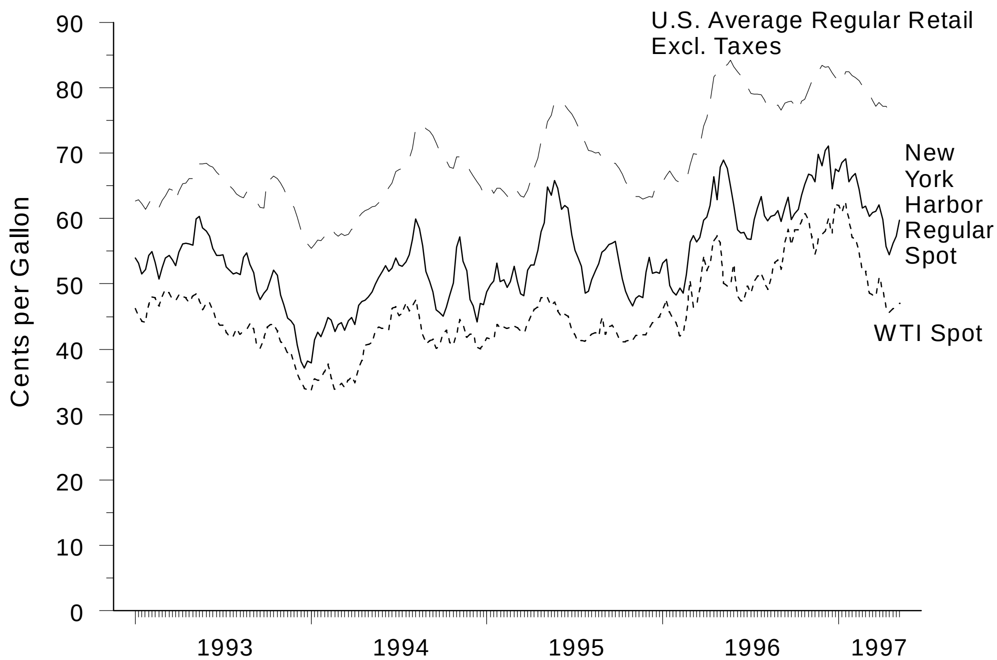
Source: Standard & Poor's Platts.

Figure 33. Spring 1997 Gasoline Price Summary
(NY Harbor Spot Conventional Regular)



Source: Standard & Poor's Platts.

Figure 34. Weekly Conventional Gasoline and Crude Oil Prices



Sources: **Spot Prices:** Standard & Poor's Platts. **Retail Prices:** Energy Information Administration (EIA), Form EIA-878, "Motor Gasoline Price Survey."

In spring 1997, crude oil markets finally seemed to be ending the tight supply/demand cycle that drove prices up in 1996. During the winter of 1995-96, oil product demand was high due to cold weather, while supplies of crude oil were less than expected. Prompt markets were tight during the spring, pushing crude oil prices higher, when a late cold snap caused prices to leap even higher to peak in April. Strong backwardation in crude oil futures persisted through 1996 as buyers kept expecting the tight prompt markets to loosen with new supplies and lower demand. With buyers expecting prices to fall, building stocks was discouraged.

Winter 1996-97 was almost a mirror image of winter 1995-96. As winter 1996-97 began, world petroleum stocks were still low, so increased demand in the fourth quarter, coupled with sluggish supply growth, again pushed crude prices up, reaching levels at the end of December higher than in April 1996. But the weather in winter 1996-97 was not as severe as the prior winter. In addition, Iraqi production entered the market in December and other supplies increased, taking the pressure off prices. EIA preliminary estimates indicate that the world petroleum stock draw was only 1.1 million barrels per day during winter 1996-97, compared to 2.0 million barrels per day the previous winter. With world stock levels appearing to recover to more normal levels, crude oil prices fell considerably through the spring of 1997, pulling gasoline prices down. While strong backwardation persisted throughout most of 1996, crude oil term structures in March and April 1997 were relatively flat.

Gasoline stocks in spring 1997 were even lower than in spring 1996, which put more pressure on gasoline spreads in 1997 than in 1996. While gasoline spreads were relatively low during the first part of 1996, they have been at or slightly above average in 1997, reflecting the extra tightness.

Retail prices averaged 17.9 cents higher in December 1996 than in 1995, but by April, were 3.3 cents lower in 1997 than in 1996. Retail prices, which lag behind the change in spot prices, had fallen 5.5 cents from December 1996 through April 1997. Thus, consumers in the spring of 1997 experienced falling gasoline prices, after the dramatic increase in prices experienced in spring 1996.

3. Oil Supply: U.S. Perspective on a Global Market

The U.S. is heavily reliant on the world crude oil market, which has been subject to huge inter-annual volatility since 1973. Neither of these facts is likely to change. Domestic crude oil production declined over the past decade, while domestic crude oil demand increased. The difference was satisfied by increased crude oil imports. The United States' proved crude oil reserves declined more than 21 percent from 1985 to 1995. Its technically recoverable crude oil resources beyond proved reserves are estimated to be about 6 times more than the year-end 1995 proved reserves. However, excepting the Gulf of Mexico and the Alaskan offshore, many of the most promising oil-prone regions of the country are presently off-limits to exploration. Over the long term — beyond 2020 or so — the United States will be increasingly unable to satisfy its crude oil requirements from domestic sources. Imported volumes and world oil prices can both be expected to rise over time, and much of the new imports will have to be obtained from the Persian Gulf region.

The market for crude oil is global. To varying degrees, every continent on Earth except Antarctica is both a producer and a consumer of crude oil. For a host of reasons having to do with factors such as how supply and demand evolved over time relative to the location and discovery sequence of commercially exploitable conventionally reservoired deposits, as well as rates of progress in the geosciences and petroleum engineering, the price of crude oil remained remarkably stable from the early 1900's through 1973 at less than $15 per barrel in constant 1992 U.S. dollars (Figure 35). For much of the time prior to 1959 the real (inflation adjusted) price was substantially less.

After 1973 the coupling of significant concentrations of supply-side market power with short-term inelasticity of demand and regional conflicts rendered the world crude oil market subject to huge inter-annual volatility. The resulting post-1970 world crude oil price path, represented by the nominal U.S. refiner acquisition cost of imported crude oil, is shown in Figure 36. It is annotated with significant events that affected the market, the U.S. actions taken in response to them, and the domestic environmental and energy conservation measures referred to or discussed in the other chapters. In keeping with the other chapters' short-term horizon, the following sections of this chapter primarily address the past decade, which began with the crude oil price collapse of 1986.

Oil Production

Domestic Production Is Declining While Demand Is Increasing

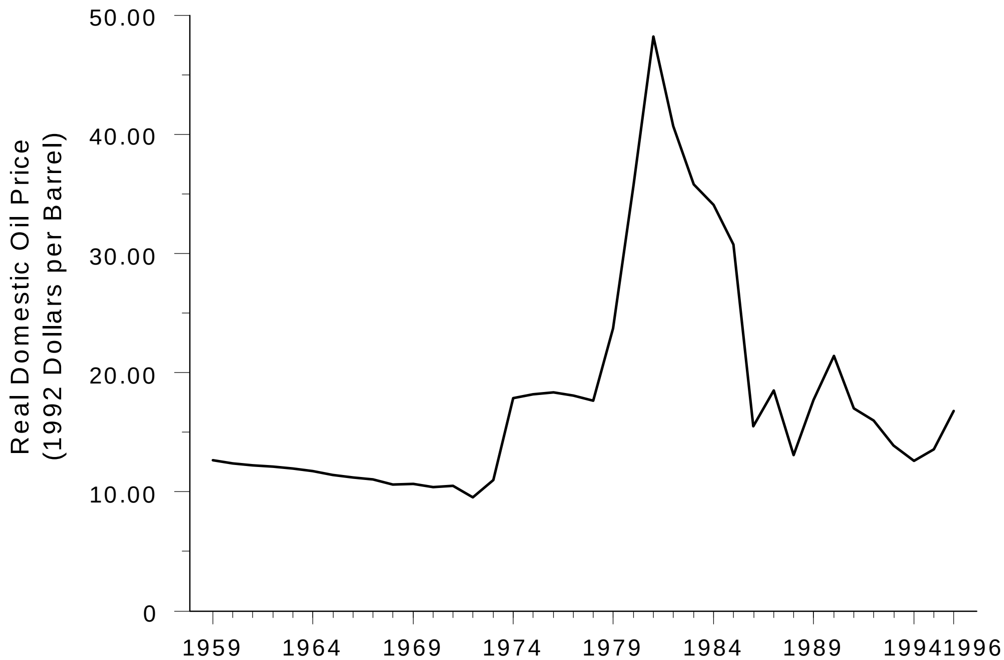
Domestic crude oil production declined over the past decade from a level of 10.2 billion barrels in 1986 to 8.6 billion barrels in 1996 (Figure 37). Domestic demand continued to rise, however, from 16.3 billion barrels in 1986 to 18.2 billion barrels in 1996. The difference was satisfied by increased imports, which have exceeded domestic production since 1994.

The U.S. is the most intensely explored and developed oil-productive nation on Earth. In 1986 there were 623,000 producing oil wells with an average daily production rate of 13.9 barrels of oil. By 1995, both the number of producing wells and their quality had declined. Eight percent fewer wells (574,000) were producing at an average daily rate of 11.3 barrels of oil (down almost 19 percent). The petroleum products that can be refined from this crude oil are summarized in the box on p. 51.

Regionally, while relative levels of production for the lower 48 States and Alaska remained about the same, total production fell 26 percent in the former and 21 percent in the latter over the 1985-1996 period. Onshore production fell 30 percent over the period and its share of total production also fell by 6 percent, while offshore production increased by almost 8 percent (Figure 38).

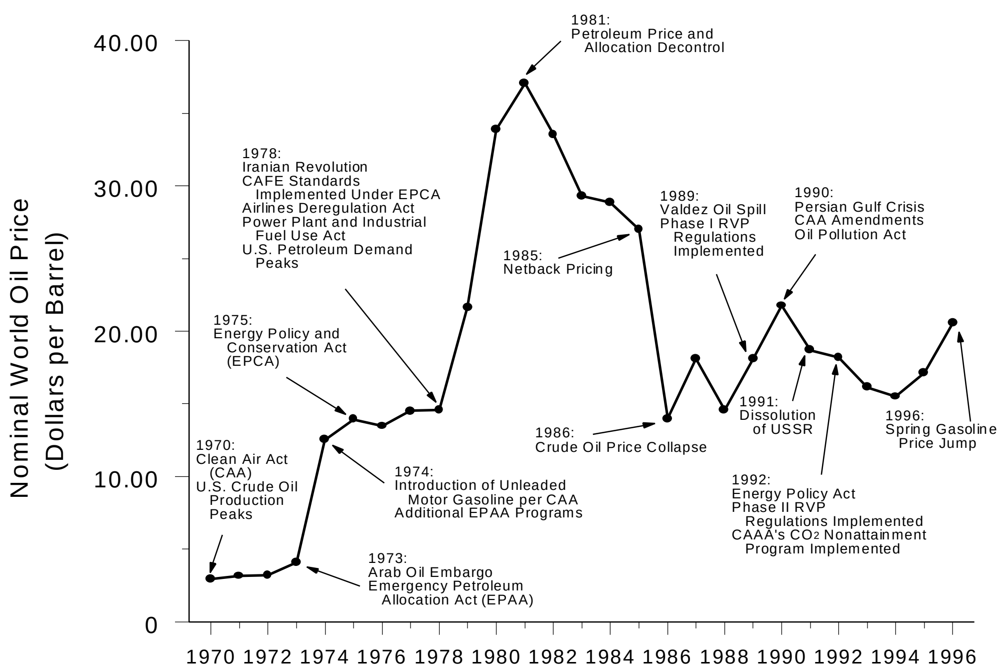
The above statistics in part reflect continuing depletion of the Nation's crude oil resource endowment, but other factors are influencing this trend. The size of new field discoveries is economically important because lifting costs per unit of production fall in response to increasing field size. In general, the largest fields in a new exploration area are among the first to be discovered. Therefore, since the onshore lower 48 States are the most intensively explored area on Earth, the remaining undiscovered oil resources occur in mostly small- to medium-size fields. During the 1985-1995 period oil exploration was prohibited or restricted in most of the few remaining domestic areas where large fields remain to be found, such as the 1002 Area within the Arctic National Wildlife Refuge (ANWR) and the southern California offshore. These restrictions resulted in an inability

Figure 35. Real Domestic Oil Price, 1959-1996



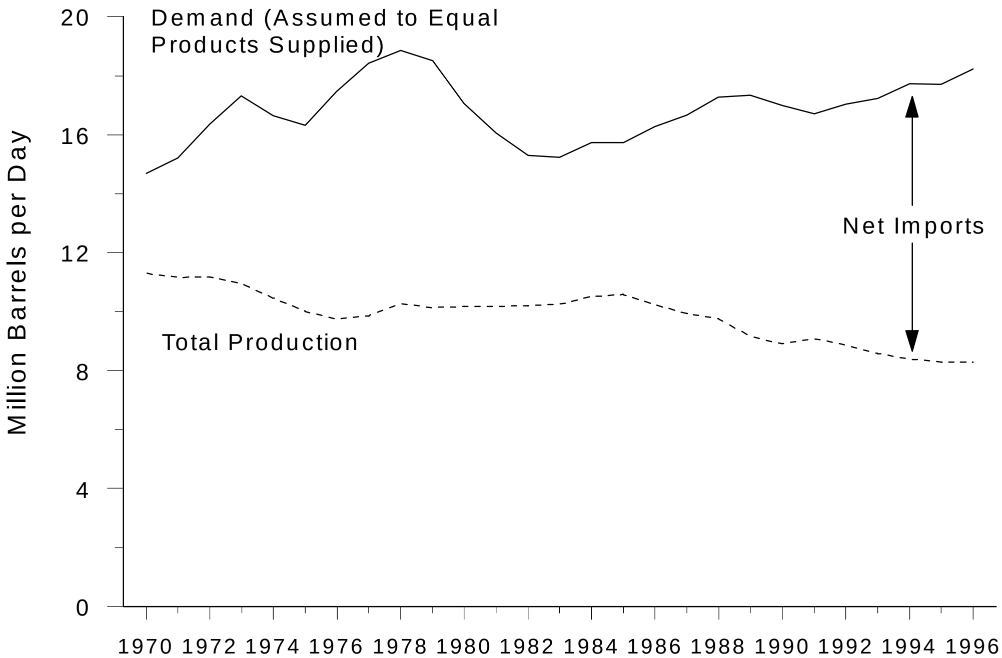
Note: Price taken to be the crude oil domestic first purchase price.
Sources: Energy Information Administration (EIA), *Annual Energy Review, 1995*; and EIA, *Monthly Energy Review* (March 1997).

Figure 36. World Oil Price and Related Events, 1970-1996



Note: World oil price taken to be the U.S. refiner acquisition cost of imported oil.
Source: Energy Information Administration, *Annual Energy Review, 1995*; and *Monthly Energy Review* (March 1997). Adapted from *The U.S. Petroleum Industry: Past as Prologue, 1970-1992*.

Figure 37. U.S. Petroleum Supply and Demand, 1970-1996



Source: Energy Information Administration, *Annual Energy Review, 1995*.

The Average 1995 U.S. Oil Well Gave Us:

Production of 11.3 barrels per day, which a refinery converted into:

6	barrels per day of motor gasoline
1.1	barrels per day of jet fuel
2.5	barrels per day of distillate fuel oil
0.6	barrels per day of residual fuel oil
2	barrels per day of heavier refined products (lubes, waxes, asphalt, road oil, etc.)

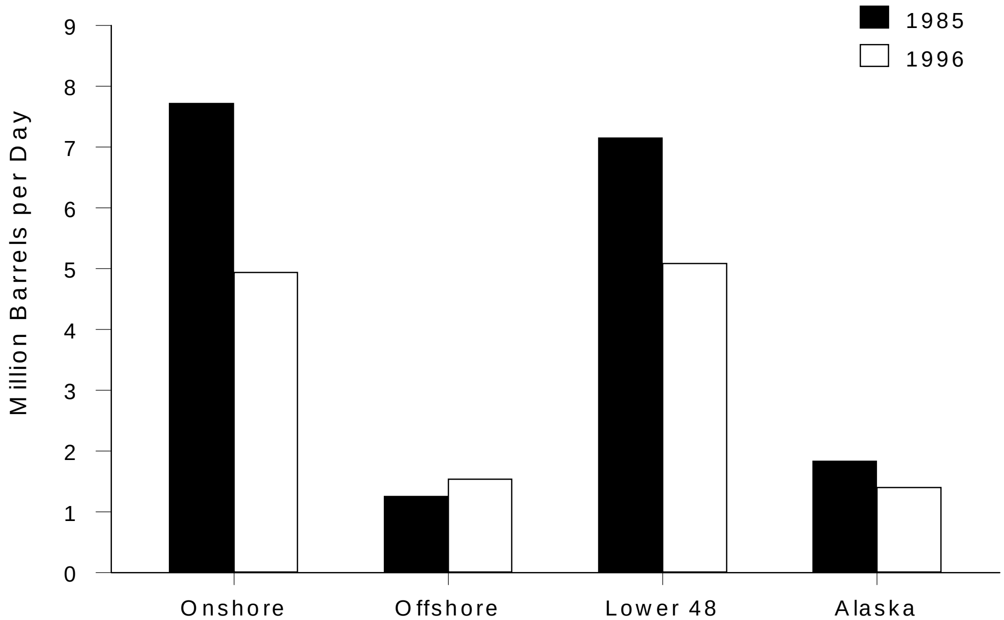
Simultaneous use of these refined products could have provided:

5,292	miles of highway travel in the average U.S. automobile. (Equivalent to the shortest round trip between Miami and San Francisco plus 56 in-town miles, or to 2000 2.6 mile utility trips.)
24	miles of air travel in a B737-700 passenger jet
62	average oil-heated homes kept comfortable on an average day
78	kilowatt hours of electricity generated with steam produced by a residual fuel oil fired boiler. (Enough electricity to power 269 light bulbs of 75 watts through one four-hour evening.)
	Minimal amounts of some of the thousands of useful things made from the heavier refined petroleum products listed above

The Bottom Line Is:

A day's production from the average U.S. oil well provides many useful products, but it does not provide much of them. Due to its very large number of low yield wells, the United States nevertheless ranked second in the world in 1995 oil production. In Saudi Arabia, the number one oil producing nation in 1995, the average oil well produced 5,800 barrels per day, or 516 times more than the average U.S. well.

Figure 38. U.S. Crude Oil Production by Site, 1985 and 1996



Sources: **1985:** Energy Information Administration, *Annual Energy Review, 1995.* **1996:** *Monthly Energy Review* (March 1997).

to maintain domestic lifting costs associated with new fields at a worldwide competitive level from 1983 to 1991. The largest U.S. exploration and production firms — and many smaller ones — therefore increasingly focused their exploration and development effort and budgets on more economically promising prospects located abroad. Trends in lifting costs, exploration, and development expenditures are portrayed by the Energy Information Administration's Financial Reporting System, an annual survey of major U.S. energy-producing companies (see Figures 39, 40, and 41).

The majors' shift away from the United States is also mirrored in Figure 42, which shows the quantities and location of production for majors and non-majors in the U.S. The majors' share of domestic onshore production has fallen steadily since 1985, by about 25 percent or 300 million barrels per year overall. Some of that production was taken over by smaller operating firms that had lower overheads. The majors invested the proceeds from the sale of some of their onshore U.S. properties primarily in frontier exploration and development projects located abroad and in the deep water Gulf of Mexico.

OPEC Leads Increase in International Production

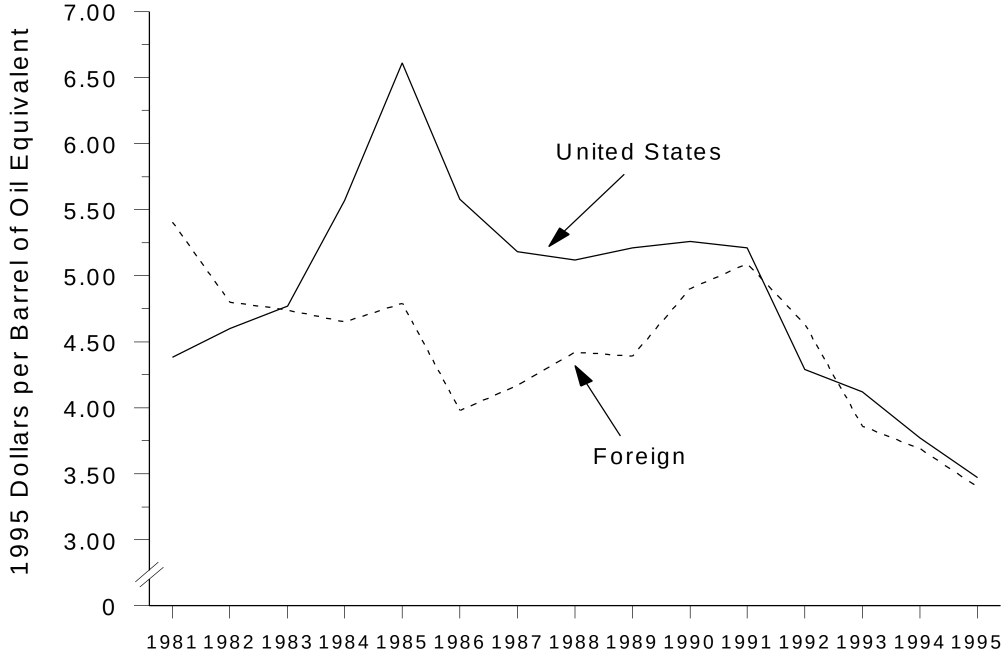
Over the past decade world crude oil production increased almost 14 percent to 64 million barrels per day in 1996. This increase is largely attributable to the member states of the Organization of Petroleum Exporting Countries (OPEC), where production increased 46.5 percent. The production of the Persian Gulf members of OPEC, which accounted for 65 percent of 1996 OPEC production, increased by 48.5 percent in the same period. There was a slight decline in non-OPEC production because increased output from such areas as the North Sea and the Pacific Rim was more than offset by declining production in mature producing areas such as the former Soviet Union and the United States (Figure 43).

Figure 44 shows the recent production trends of the four largest oil producing countries. Saudi Arabia's production more than doubled during the first part of the past decade, while the Soviet Union/former Soviet Union's production decreased by half. Table 2 shows the worldwide production of the 20 leading companies in 1972 and 1995, when they respectively accounted for 74.6 and 63.1 percent of world production. The change in the names and rankings of the top 20 firms reflects the spate of nationalizations or expropriations that took place in the mid-1970s.

Oil Reserves

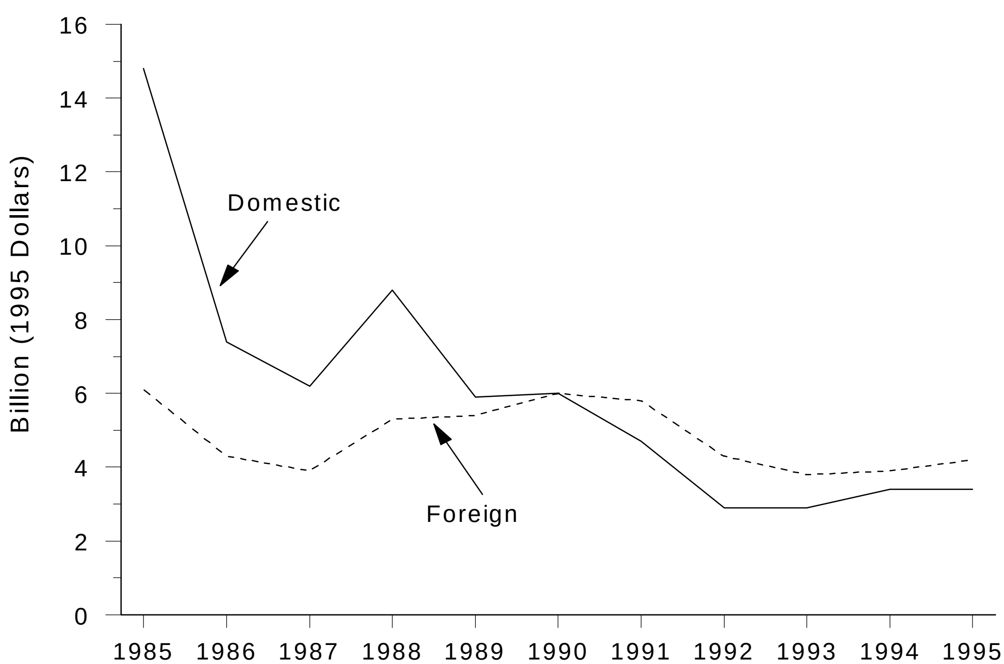
Proved reserves are those volumes of oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from know reservoirs under existing economic and operating conditions.

Figure 39. Direct Oil and Gas Lifting Costs for FRS Companies, 1981-1995



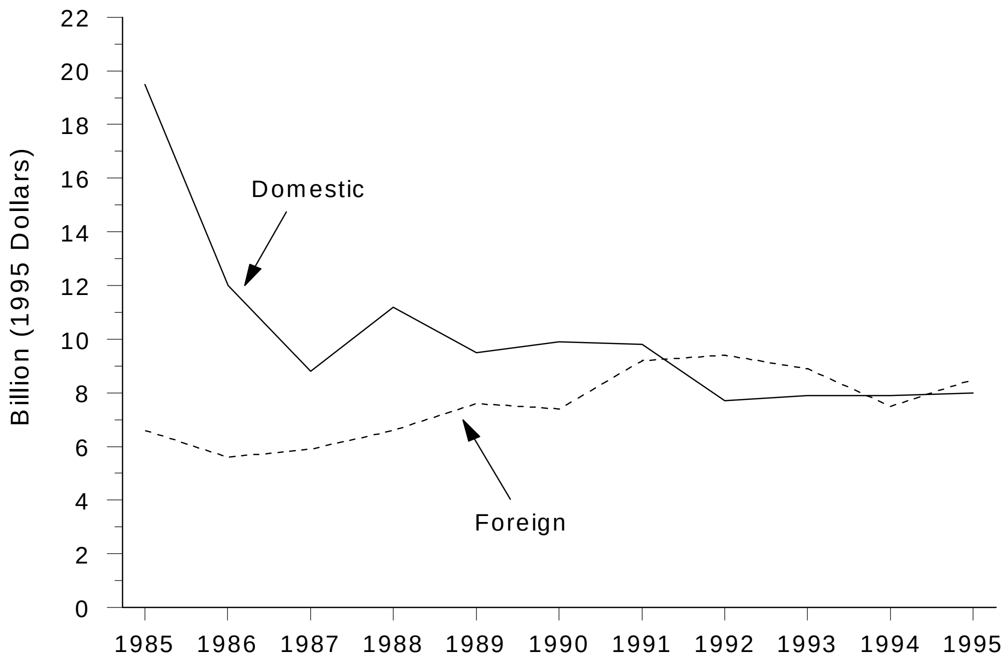
Source: Energy Information Administration, Financial Reporting System (FRS), *Performance Profiles of Major Energy Producers 1995.*

Figure 40. Exploration Expenditures by FRS Firms, 1985-1995



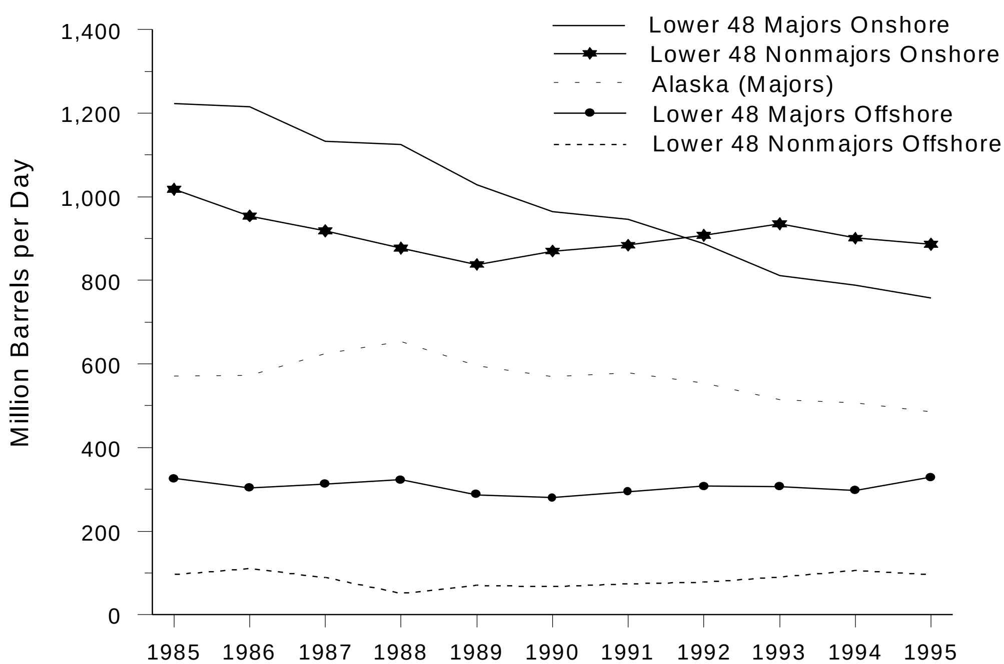
Note: Includes expenditures for unproved acreage.
Source: Energy Information Administration, Financial Reporting System (FRS), Form EIA-28.

Figure 41. Development Expenditures by FRS Firms, 1985-1995



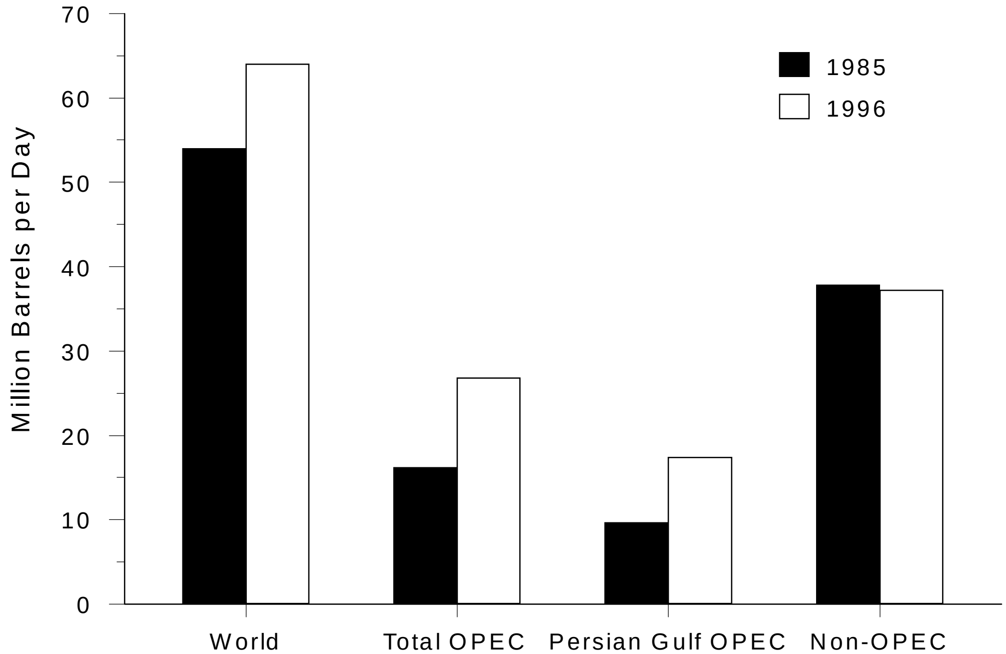
Note: Includes expenditures for proved acreage.
Source: Energy Information Administration, Financial Reporting System (FRS), Form EIA-28.

Figure 42. Majors and Nonmajors, U.S. Oil Production by Region, 1985-1995



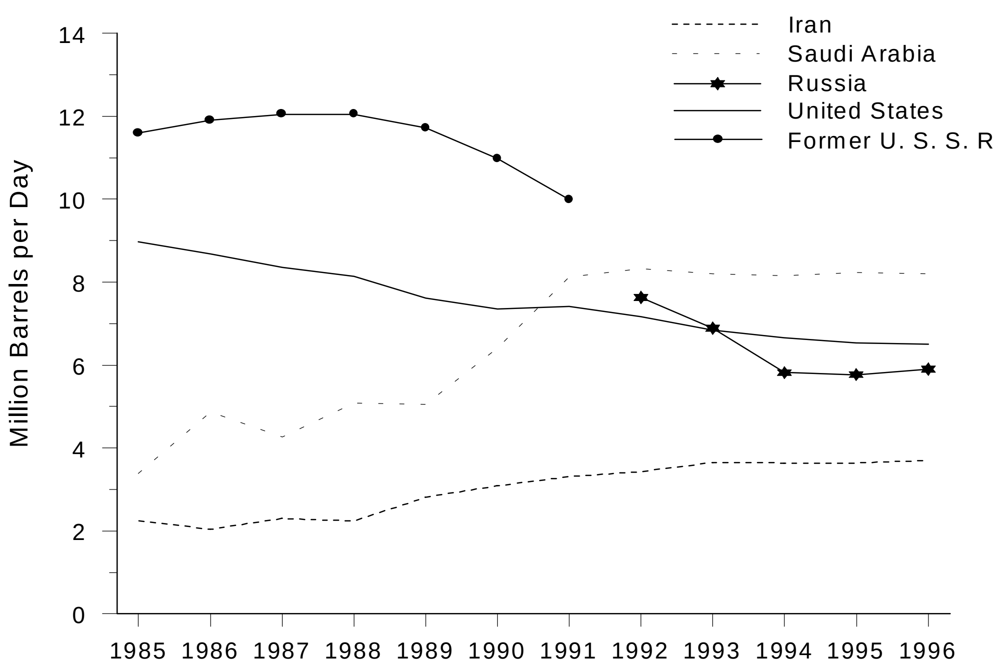
Source: Energy Information Administration, *Oil and Gas Development in the United States in the Early 1990's* (October 1995), and Financial Reporting System.

Figure 43. World, OPEC, and Persian Gulf Oil Production, 1985 and 1996



Source: Energy Information Administration, *Monthly Energy Review* (March 1997).

Figure 44. Leading World Oil Producers, 1985-1996



Source: Energy Information Administration, *Monthly Energy Review* (March 1997).

Table 2. Worldwide Crude Oil Production of 20 Leading Companies, 1972 and 1995
(Thousand Barrels per Day)

1972			1995		
Company	Production	Percent of Worldwide Total	Company	Production	Percent of Worldwide Total
Exxon Corp.	4,968	10.8	Saudi Arabian Oil	8,585	13.8
British Petroleum	4,664	10.1	National Iranian Oil Co.	3,720	6.0
Royal Dutch/Shell	4,169	9.0	Petroleos de Venezuela	2,885	4.6
Texaco Inc.	3,777	8.2	China National Petroleum	2,796	4.5
Chevron Corp.	3,232	7.0	Petroleos Mexicanos	2,722	4.4
Gulf Oil	3,214	7.0	Royal Dutch/Shell	2,254	3.6
Mobil Corp.	2,316	5.0	Kuwait Petroleum Corp.	2,070	3.3
Communist Bloc[a]	1,301	2.8	Exxon Corp.	1,726	2.8
CFP (Total - France)	977	2.1	Libya National Oil Company	1,345	2.2
Sonatrach (Algeria)	925	2.0	Abu Dhabi National Oil Co.	1,300	2.1
Amoco Corp.	815	1.8	Sonatrach (Algeria)	1,283	2.1
ARCO	652	1.4	British Petroleum	1,283	2.1
DuPont (Conoco)	594	1.3	Nigerian National Petroleum	1,200	1.9
USX Corp. (Marathon)	453	1.0	LUKoil (Russia)	1,116	1.8
Petroleos Mexicanos	440	1.0	Pertamina (Indonesia)	1,065	1.7
Occidental Petroleum	443	0.9	Chevron Corp.	1,001	1.6
Getty Oil	443	0.9	Mobil Corp.	810	1.3
Sun Co.	369	0.8	Elf Aquitaine (France)	764	1.2
Unocal Corp.	365	0.8	Texaco Inc.	762	1.2
Phillips Petroleum Co.	337	0.7	Yokos (Russia)	722	1.2
Top 20 Total	**34,434**	**74.6**	**Top 20 Total**	**39,409**	**63.1**
Worldwide Total[a]	**46,170**	**100.0**	**Worldwide Total**	**62,446**	**100.00**

[a]For 1972, only non-communist world oil production and communist bloc (including China) exports to the non-communist world are included, while 1995 includes total world production. Sum of components may not equal totals due to independent rounding. Shares were calculated based on unrounded data.

Sources: Energy Information Administration (EIA). **1972:** EIA, *Performance Profiles of Major Energy Producers 1993*. **1995:** EIA, Financial Reporting System.

Domestic Reserves Declined Over the Past Decade

In the past decade, the United States' proved reserves of crude oil have fallen gradually, declining over 21 percent from 28.4 billion barrels in 1985 to 22.3 billion barrels in 1995 (Figure 45). The last inter-annual increase, amounting to about 400 million barrels, occurred between 1986 and 1987. As Figure 46 indicates, proved reserves of crude oil increased only in the offshore Gulf of Mexico during the decade.

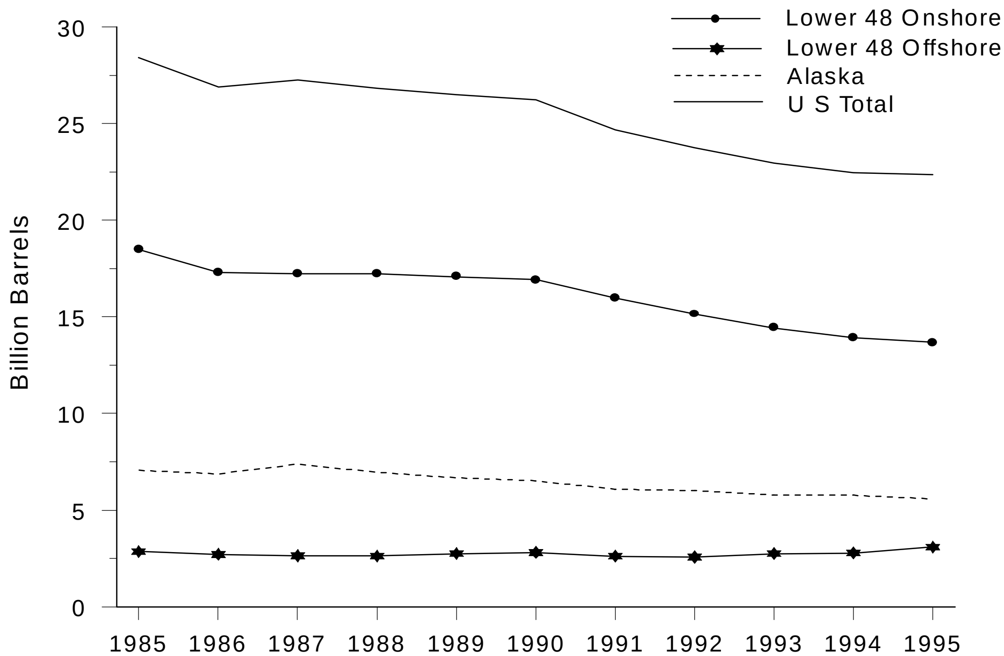
This reserves record is primarily attributable to the sharp decrease in drilling caused by the 1986 collapse of crude oil prices, which declined 49 percent worldwide and 51 percent in the domestic market (Figure 47).[14] Domestic crude oil well completions dropped 47 percent in 1986 alone, from 35,021 in 1985 to 18,701, while exploratory oil well completions similarly declined from 1,879 in 1985 to 988 (Figure 48). A secondary factor was the shift toward gas drilling that took place during the period. After 1992 natural gas rather than crude oil became the dominant domestic drilling target.

Restrictions on oil exploration in many of the most prospective oil-prone places left in the United States, due to environmental considerations, also contributed to the decline of domestic proved crude oil reserves. Alaska on- and offshore, the Gulf of Mexico, and the far western United States[15] are the only regions of the country in which undiscovered conventional oil and gas resources sufficiently large to be of long term national supply significance remain to be found and converted to supply at low levels of unit cost relative to other current and foreseeable oil and gas supply alternatives. This is consistently shown by:

[14]Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, Annual Report 1995, DOE/EIA-0216(95), Table 3, p. 10.

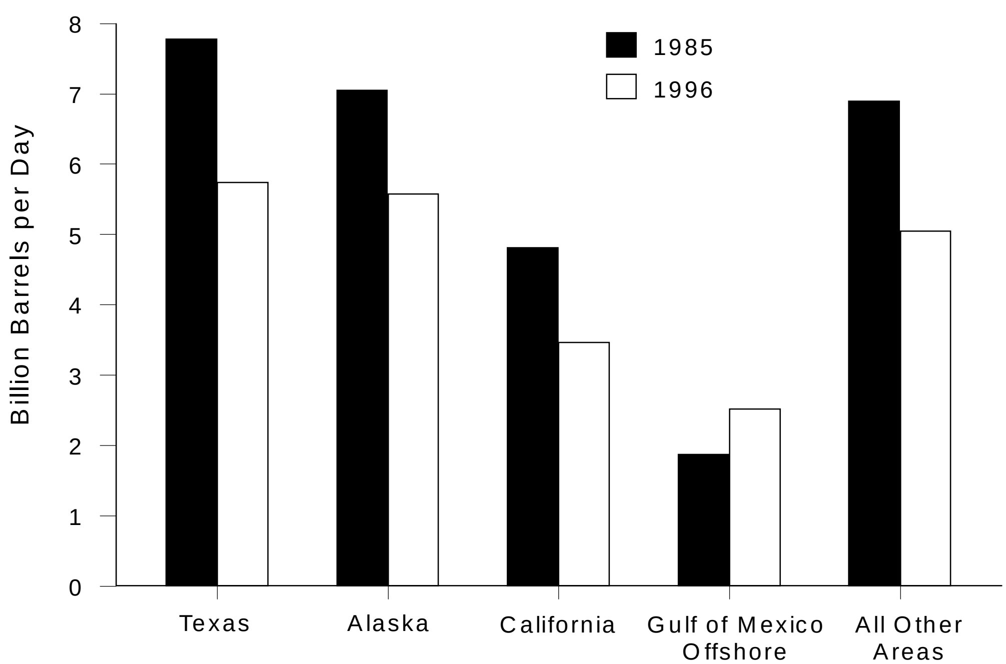
[15]On- and offshore Washington, on- and offshore Oregon, on- and offshore California, Idaho, Nevada, and parts of Utah and New Mexico.

Figure 45. Domestic Crude Oil Proved Reserves, 1985-1995



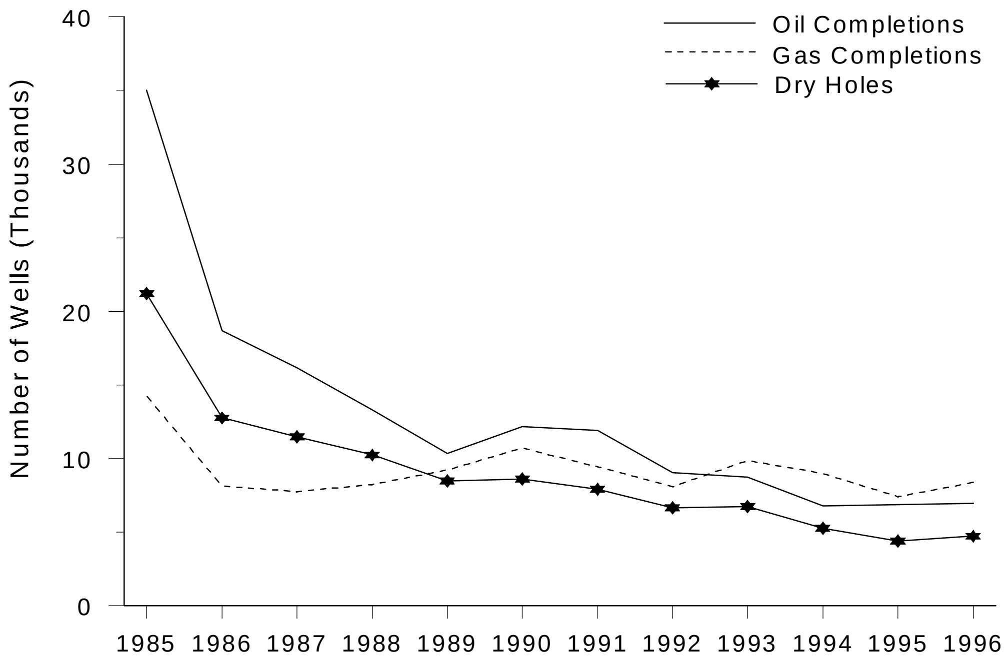
Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1995*.

Figure 46. Crude Oil Proved Reserves by Area, 1985 and 1996



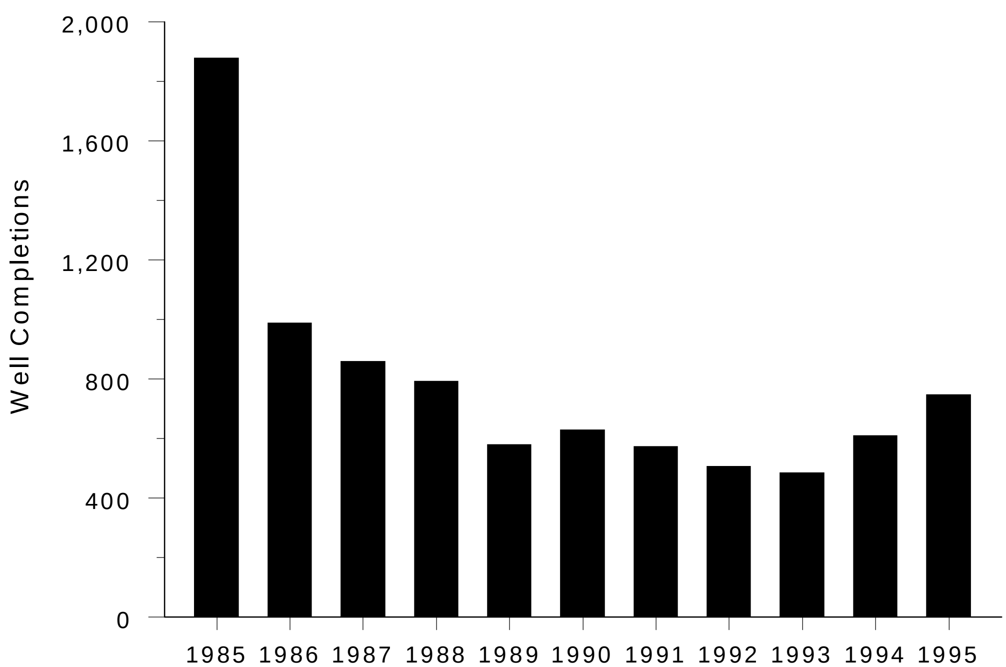
Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1995*.

Figure 47. Domestic Oil and Gas Well Completions, 1985-1996



Source: Energy Information Administration, *Monthly Energy Review* (March 1997).

Figure 48. Domestic Exploratory Oil Well Completions, 1985-1995



Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1995.*

- periodic estimates of domestic undiscovered oil and gas resources produced by the United States Geological Survey and the Minerals Management Service;[16]

- biennial estimates of natural gas resources prepared by the industry-based Potential Gas Committee;[17]

and is demonstrated in the EIA publication *Geologic Distributions of U.S. Oil and Gas*.[18] However, the most oil-prospective areas of onshore Alaska and offshore California have for years been administratively or legislatively declared off-limits to oil and gas exploration.

A factor that prevented the Nation's 1995 crude oil reserves situation from being worse was that discoveries per exploratory well completion generally increased over the decade (Figure 49). This occurred in part because the lower overall level of drilling permitted "high grading" of the portfolio of prospects available to the industry, and in part was due to the introduction of several new technologies that increased the drilling success rate or otherwise reduced either the risk or cost of upstream operations (see box, p. 61).

International Reserves Are Much Larger Than U.S. Reserves

Crude oil resources and the reserves derived from them are unevenly distributed over the globe. Based on country-by-country estimates of crude oil reserves and production compiled from multiple sources by DeGolyer and MacNaughton[19], the world's reserves of crude oil were 1,114.7 billion barrels at year-end 1994 while 1994 world production was 22.632 billion barrels. The distribution of these quantities is shown in Table 3 for the continents and the Middle East region. The 1994 worldwide ratio of year-end reserves to annual production (R/P) was 49.2. This statistic, often inaccurately and misleadingly termed a "reserve life index," *does NOT imply* that the world's year-end 1994 reserves will be exhausted in 49.2 years. The 1994 reserves base will instead produce at generally decreasing levels to well beyond 2050. The R/P statistic is more useful for comparative purposes. Table 3 indicates the general worldwide 1994 distribution of crude oil reserves and production and provides some location-specific R/P ratios. The United States' R/P of 9.3 was the lowest of any major oil- producing country or area. This reflects the fact that the United States is the most intensively explored country in the world, having been the first to achieve an annual production rate of a billion barrels per year.

Oil Resources

Estimates of recoverable oil resources are subject to a greater degree of uncertainty than are estimates of proved reserves. They include, in addition to proved reserves, oil that is yet to be discovered and other classes of reserves that are generally less precisely quantifiable than proved reserves. Their eventual recovery is less assured.

Domestic

Based on year-end 1993 data for onshore and state jurisdiction offshore areas and year-end 1994 data for Federal jurisdiction offshore areas, the Department of the Interior's 1995 mean (expected value) estimate of undiscovered recoverable plus inferred resources of domestic crude oil was 132 billion barrels.[20] This volume includes both anticipated new field discoveries and the expected appreciation of the ultimate recovery estimates of existing fields for both conventional and unconventional types of deposits. It is about 6 times larger than year-end 1995 proved reserves.

International

The Federal government's estimates of world oil and gas resources are produced by the United States Geological Survey's (USGS's) World Energy Resources Program (WERP). The latest estimate, dated January 1, 1993, is that a mean (expected value) of 547 billion barrels of technically

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[16] United States Geological Survey, *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States*, Circular 725 (Washington, DC, 1975); United States Geological Survey, *Estimates of Undiscovered Recoverable Conventional Oil and Gas Resources in the United States*, Circular 860 (Washington, DC, 1981); United States Department of the Interior, U.S. Geological Survey, and Minerals Management Service, *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States -- A Part of the Nation's Energy Endowment* (Washington, DC, 1989); United States Geological Survey, *1995 National Assessment of United States Oil and Gas Resources*, Circular 1118 (Washington, DC, 1995); Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, 1996).

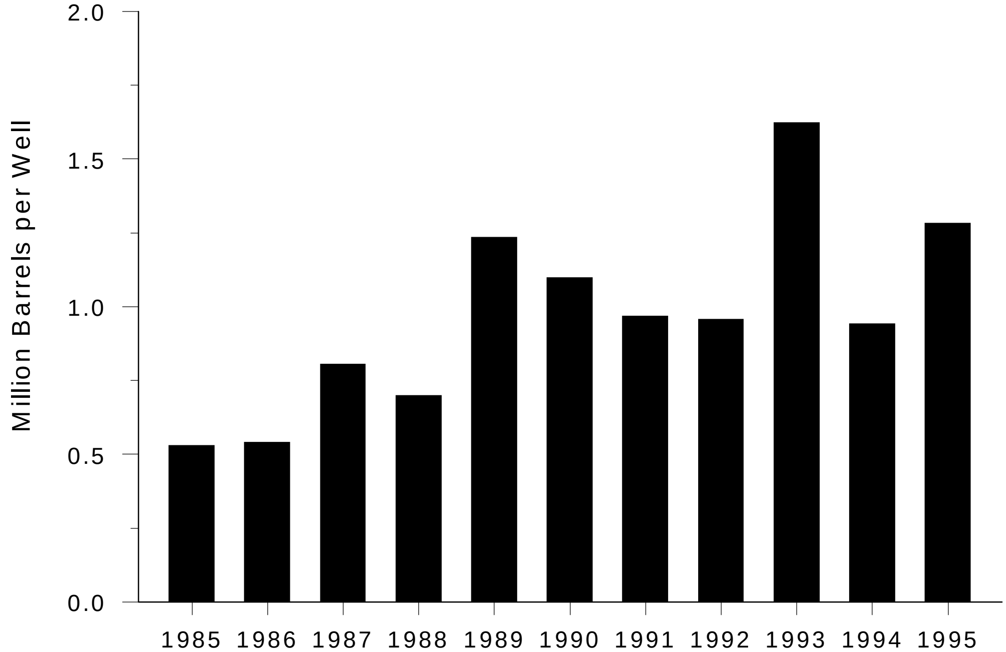
[17] Potential Gas Committee, *Potential Supply of Natural Gas in the United States*, biennial series through 1996, (Golden, CO).

[18] Energy Information Administration, *Geologic Distributions of U.S. Oil and Gas*, DOE/EIA-0557 (Washington, DC, July 1992).

[19] DeGolyer and MacNaughton, "Estimates of Petroleum Reserves in Principal Producing Countries and Crude Oil Production in 1994," *Twentieth Century Petroleum Statistics*, (Dallas, TX, 1995), p. 1.

[20] United States Geological Survey, *1995 National Assessment of United States Oil and Gas Resources*, Circular 1118, (Washington, DC, 1995); Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, 1996).

Figure 49. Domestic Crude Oil Discoveries per Exploratory Oil Well Completion, 1985-1995



Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1995*.

recoverable crude oil remains to be discovered worldwide (Table 4). There is a 19 in 20 chance that at least 43 billion barrels remain to be discovered, and a 1 in 20 chance that at least 945 billion barrels remain to be discovered.[21]

The geographic distribution of the mean estimate is as follows: 30.1 percent is expected to be located in the Americas, 22.3 percent in the Middle East, 18.5 percent in the former Soviet Union, 14.8 percent in Asia-Oceania, 8.8 percent in Africa *ex* the Middle East, and just 5.5 percent in Europe, Western, and Eastern.

It should also be noted that those places with the highest current R/P ratios, as shown in Table 3, also usually have the highest estimated volumes of undiscovered oil resources. This reflects two facts about these places: they are *very* oil-rich; and, in most instances, exploration and development began much later in them than in the United States.

Future Implications

The United States' proved crude oil reserves could exhibit a modest increase commencing this year or next given recent developments in the Gulf of Mexico where:

- 3-D seismic surveying technology has within the past decade made it possible to accurately image reservoirs located in the deep Gulf (i.e., in more than 1000 feet of water) and beneath the extensive salt sheets that occur in the shallower portions of the Gulf;

- the development of new production technologies applicable to deep water, such as tethered floating drilling and production platforms (tension leg platforms), spar buoy-shaped production facilities, and sub-sea well completion and production systems, has made it profitable to develop large deep water fields.

Also contributing to the possibility of a modest near-term increase in domestic oil reserves are the efforts now underway to find and/or develop the so-called "smaller" oil reservoirs and fields peripheral to the existing giant producing fields on the North Slope of Alaska, each of which is a big field by lower 48 States-standards. However, in view of the remaining undiscovered resource situation, the continued restrictions on oil exploration in many highly prospective oil-prone areas, and the inexorable if slow growth of demand, this increase can only be temporary, lasting a few years at most.

The industry is also engaged in a large effort to increase its proved crude oil reserves in South America, which has short-haul access to the United States market. Over the mid-term

[21] C.D. Masters, D.H. Root and E.D. Attanasi, *Resource Constraints in Petroleum Production Potential*, Science, v. 253 (12 July 1991).

New Upstream Technologies: What They Deliver

Three-Dimensional Seismic Surveying

Three-dimensional seismic surveying (3-D), made possible by the computer revolution, improves the precision and content of geological interpretations of the earth's subsurface far beyond what the traditional two dimensional (2-D) seismic surveying methods provided. Widespread implementation of 3-D in the past decade has led to a much higher ratio of successful wells to dry holes, particularly for exploratory wells.

Horizontal Drilling, Measurement-While-Drilling, and Logging-While-Drilling

Horizontally-oriented wells typically produce at 3 to 5 times the rates achieved by conventional vertical wells drilled into the same reservoir. While they are more difficult and expensive to drill, using them tends to approximately halve the average unit cost of development. They, along with other kinds of directional drilling, also allow the industry to have a much smaller surface "footprint" because areas up to several square miles can be tapped from a single drilling site. This characteristic of horizontal drilling is particularly important in frontier areas such as the Arctic and the deep offshore, and in environmentally sensitive areas.

New downhole technologies which enabled the drilling of horizontal holes that stay within the target formation include measurement-while-drilling (MWD) and logging-while-drilling (LWD) systems. MWD systems allow real-time acquisition of previously unavailable data related to the drilling operation itself such as weight-on-bit, mud pressure, torque, vibration, and hole caliper, angle and direction. LWD systems allow real-time acquisition of downhole resistivity and sonic and gamma ray measurements that rival those attainable via traditional progress-interrupting wireline logging. These geophysical measurements can be simultaneously interpreted to determine rock type (sandstone versus shale versus carbonates) and pore content (water versus hydrocarbons). Having this knowledge in real time allows path correction commands to be sent back down the hole to a steerable motor located just behind the drill bit and just in front of the MWD and LWD tools. Thus, the position of the bit can now often be controlled to within 2 feet of the intended (design) position.

Slim Hole Drilling

Slim hole drilling, the drilling of wells with smaller diameter bores than those drilled over the past several decades, is rapidly increasing. Major technological strides have been made in downsizing the traditional suite of downhole instruments and tools without loss of effectiveness during the last few years. The principal advantage of slim hole drilling is reduced cost. For example, steel is priced by the ton and 1,000 feet of conventional 12.25 inch hole casing weighs 59 tons, while the equivalent length of 8.5 inch casing weighs only 29 tons. Similarly, lower costs are associated with drill pipe, drill bits, fuel costs, mud chemicals, cement, cuttings cleaning and disposal, and elapsed drilling time to total depth.

Drilling With Coiled Tubing

Standard drill pipe comes in 30 foot lengths with threaded connections at the ends. It is typically stored on a drilling rig's pipe rack in 90 foot stands made up of 3 joints, which must be sequentially added to the drill string while drilling. Similarly the stands must be sequentially decoupled to change the downhole tools and drill bit. "Tripping" to do so is a laborious, time consuming, expensive way to drill. Thanks to recent developments in the material sciences standard drill pipe is being replaced in many drilling applications with coiled tubing. This is a continuous length of pipe which is stored wrapped around a large reel. It is straightened off the reel over a curved guide to and through a motorized injector head mounted atop the well control stack, and thence down the well. Coiled tubing wall thickness ranges from 0.2 to 0.5 inches depending on the tubing's diameter and the required load-bearing characteristics. Several thousand feet of coiled tubing can be run down or withdrawn from a hole in tens of minutes rather than the many hours required to "trip" with standard drill pipe, providing substantial cost savings. Another advantage over standard drilling technique is that fluid circulation in the hole can be maintained at all times, which helps to avoid a number of well control, drilling, and well completion problems.

Nuclear Magnetic Resonance Borehole Imaging

Downhole tools have recently been developed that perform nuclear magnetic resonance (NMR) analysis of the hydrogen-containing fluids located in near-borehole rock. NMR can quantitatively differentiate between (1) hydrogen atoms bound to clays, (2) hydrogen atoms included in water molecules, and (3) hydrogen atoms included in hydrocarbon molecules. This knowledge enables both better well completion design and the completion of thinner productive zones than before.

Integrated Teams and Petroleum System Modeling

Prior to the 1980s, most oil and gas firms were structured in such a way that their exploration geologists and their geophysicists had minimal contact with each other and neither group talked to the development geologists and production staff. Each had separate sets of data and there was little communication. This situation has radically changed, in most firms, for the better. Exploration and development teams consisting of all disciplines operate off the same computer-housed data base, thereby avoiding disconnects and bringing the best thinking of all involved in finding, developing and producing a field or reservoir to bear at the same time. Adjunct to this approach is the developing area of petroleum systems modeling, which has been made possible by the advent of fast computers capable of massive processing tasks. A petroleum system consists of the source rocks, migration pathways, traps, and seals required to generate, accumulate, and preserve oil or gas in the subsurface. These elements of a petroleum system have to have occurred in an appropriate time relationship for a commercially exploitable oil or gas reservoir to be present. It has now become possible to model the generation of oil and/or gas from the kerogen present in the source rocks, the formation of overlying traps and their seals, the expulsion of oil or gas from the source rocks, and migration to the traps. While such models are as yet fairly rudimentary, and much more data and therefore even faster computers are needed to improve them, only individual components had been modeled before. Integrated petroleum system modeling is a major improvement that helps to avoid technical disconnects in the analysis of the system. In several instances it has demonstrably reduced the required exploration expenditures and speeded the exploration process by accurately indicating what traps within the target system were likely to be commercially productive.

Table 3. Distribution of Crude Oil Reserves and Production with Corresponding Local R/P Ratios, 1994

Area/Country	Percent of World Reserves	Percent of World Production	R/P Ratio
North America	7.28	18.11	20.0
United States	2.01	10.74	9.3
South America	7.33	8.20	43.1
Venezuela	5.82	4.17	68.5
Europe	3.28	9.38	17.2
United Kingdom and Norway	2.91	8.1	17.6
Former Soviet Union	17.15	11.84	71.6
Africa	6.53	10.73	30.2
Nigeria	1.54	3.06	25.0
Middle East	53.69	30.69	86.0
Saudi Arabia	23.32	12.86	89.3
Asia-Oceania	4.75	11.04	21.0

Note: R/P = Year-end reserves divided by annual production.

Source: Derived from DeGolyer and MacNaughton, "Estimates of Petroleum Reserves in Principal Producing Countries and Crude Oil Production in 1994," *Twentieth Century Petroleum Statistics* (Dallas, TX, 1995), p.1.

this source of crude oil supply, particularly from Venezuela, will be significant for the United States. However, South America is estimated to have only about 7 percent of the world's undiscovered conventional crude oil resources. It is not therefore expected to be a major source of long-term supply unless and until means can be developed to economically tap its large known resources of heavy oil.

Regardless of what transpires in relation to exploitation of the United States' remaining domestic crude oil resources, it is clear that the upstream sector of the petroleum industry has increasingly focused on foreign opportunities over the past decade. As noted earlier and shown in Figure 39, the direct lifting costs of EIA's Financial Reporting System (FRS) companies, which include all of the domestic majors, were lower abroad than they were in the United States from 1983 to 1991. Since 1991 there has been no important distinction between foreign and domestic lifting costs, but there has been no change in the emphasis on foreign operations. And, as shown in Figures 40 and 41, expenditures by the majors on foreign operations increased for both exploration and development from 1987 through 1990-1991, flattened out or declined slightly for two to three years, and then began to increase again slightly. The majors are simply following the available resource base on a world scale, enabled by the liberalization/rationalization of ownership, leasing, and tax policies that was initiated by many oil-prospective countries during the past decade.

Over the long term — beyond 2020 or so — the United States will be increasingly unable to satisfy from domestic sources its requirements for crude oil. Considering the limited long-term domestic capability to produce crude oil and increasing demand, the United States will become increasingly reliant on imported crude oil.[22]

There continues to be a lack of economical substitutes for the the products derived from crude oil, most particularly motor gasoline. This, in concert with the anticipated rapid growth of petroleum product demand in developing countries, will lead to increasing international competition for crude oil.[23] Future crude oil imports will therefore likely be obtained at increasing prices until such time as a cap is placed on world crude oil prices by one or more of the emerging natural gas-to-liquids, coal-to-liquids, or heavy oil recovery technologies.

As a consequence of the natural distribution of petroleum resources, much of the United States' out year-supply will have to be imported from the Persian Gulf region, which has a history of supply disruptions induced by political events.

[22]Comparison of crude runs to domestic stills with domestic crude oil production indicates that the U.S. has not come within 10 percent of being crude oil self-sufficient since 1957, and that there has been a pronounced reduction of self-sufficiency since 1982, to the point that 53 percent of 1995's crude runs were of a foreign origin. While it is highly improbable that the U.S. can attain crude oil self-sufficiency again, it remains possible to assert some control over the magnitude and timing of future insufficiencies.

[23]Energy Information Administration, *International Energy Outlook 1997*, DOE/EIA-0484(97), (Washington, DC, April 1997).

Table 4. Estimates of Worldwide Cumulative Production, Identified Reserves, and Undiscovered Technically Recoverable Resources of Conventional Crude Oil
(Billion Barrels)

Area	Cumulative Production 1/1/93	Identified Reserves 1/1/93	Mean Undiscovered Resources
North America	182.8	83.0	121
Canada	14.3	7.0	33
Mexico	15.7	27.4	37
United States	152.7	48.5	49
Other	0.1	0.1	1
South America	57.9	43.8	44
Argentina	4.9	2.3	2
Brazil	2.5	2.8	9
Venezuela-Trinidad	43.9	34.4	20
Other	6.7	4.3	14
Europe	22.5	28.9	30
Netherlands	0.5	0.2	0
Norway	3.1	11.0	13
United Kingdom	8.6	13.5	11
Other Western Europe	3.5	2.2	4
Eastern Europe	6.8	2.0	2
Former Soviet Union	103.6	80.0	101
Africa	46.4	58.7	48
Algeria	9.1	8.4	2
Angola	1.3	2.0	2
Egypt	4.4	4.6	5
Libya	15.9	22.4	8
Nigeria	12.4	16.0	9
Other	3.2	5.3	21
Middle East	160.2	584.8	122
Iran	36.1	63.0	22
Iraq	19.9	99.0	45
Kuwait	23.3	96.0	3
Saudi Arabia	55.8	255.0	41
United Arab Emirates	11.0	56.2	27
Other	14.2	15.6	4
Asia-Oceania	36.8	42.8	81
Australia-New Zealand	3.0	2.4	5
China	13.0	22.0	48
India	2.6	4.5	3
Indonesia	13.3	8.4	10
Malaysia-Brunei	3.9	4.6	6
Other	0.9	1.0	8
World	610.2	922.1	547

Source: From Masters, C.D., Root, D.H., and Attanasi, E.D., *Resource Constraints in Petroleum Production Potential,* Science, v. 253 (12 July 1991), p. 147.

4. U.S. Crude Oil Imports: Growing U.S. Dependence

U.S. petroleum import dependency has almost doubled since the mid-1980's, to 8.4 million barrels a day. Crude oil import dependency has risen even faster. By 1996, crude oil accounted for nearly 90 percent of net imports, and U.S. refiners were running over 1 million barrels a day more imported than domestic crude. This chapter examines the decade of growth in U.S. crude oil imports, and describes the role that factors such as the regional shifts in the U.S. and world supply/demand balances, the expanded capability of the U.S. refinery complex, and environmental legislation have played in changing the quality and sources of these imports.

Introduction

Total U.S. imports of crude oil and petroleum products have increased dramatically since the mid-1980's, reaching a record 9.4 million barrels a day last year and accounting for over half the oil used domestically. Petroleum exports also increased over the same period, but only modestly. Thus, net U.S. petroleum import dependency has risen sharply, to 8.4 million barrels a day, and cost the U.S. nearly $60 billion last year. Both the country's thirst for and dependence on imports are still growing.

The majority of the imports – but the minority of exports – are crude oil. The U.S. has been a net importer of crude for almost half a century, but it was not until 1994 that it imported more than it produced. Since then, the gap has widened to almost 1.0 million barrels per day. Also since then, exports of Alaskan North Slope crude have been liberalized.

This chapter looks at how crude oil imports have evolved over the last ten years, focusing not only on what has driven the volume growth but also on the role that crude quality, regional shifts in U.S. and global supply/demand balances, and environmental legislation have played in the changing mix of crude sources. It also considers some of the economic, logistical, and political implications of these changes. While the focus of this chapter is therefore on crude oil (rather than products) and on imports (rather than exports), the discussion must begin with a broader view of the import-export picture to provide the necessary context for understanding the relative role of crude oil imports.

U.S. Total Oil Imports

The record 9.4 million barrels per day of crude oil and petroleum products imported by the U.S. last year keep it firmly at the top of the world importer rankings (Figure 50). In the mid-80's, the U.S. was only importing 5.0 million barrels per day, barely half of today's level. But the trend has not always been up. Gross imports had reached 8.8 millions of barrels per day back in 1977, before collapsing over the following six years. Because of the substantial growth in exports, net imports (imports minus exports) just failed to set a new record in 1996, averaging 70 thousand barrels a day less than in 1977.

Imports Driven by Increasing Demand and Declining Production

U.S. gross import dependency has fluctuated broadly in line with the fluctuations in import volumes. It reached a peak of 48 percent back in 1977, dropped to 32-35 percent between 1982 and 1985, and then picked up fairly steadily to reach 52 percent last year. While this was a new record, it was not the first time the politically sensitive 50 percent level had been exceeded. That also happened in both 1993 and 1994. Net imports dependency reached 46 percent of demand, nearly equaling the 1977 record.

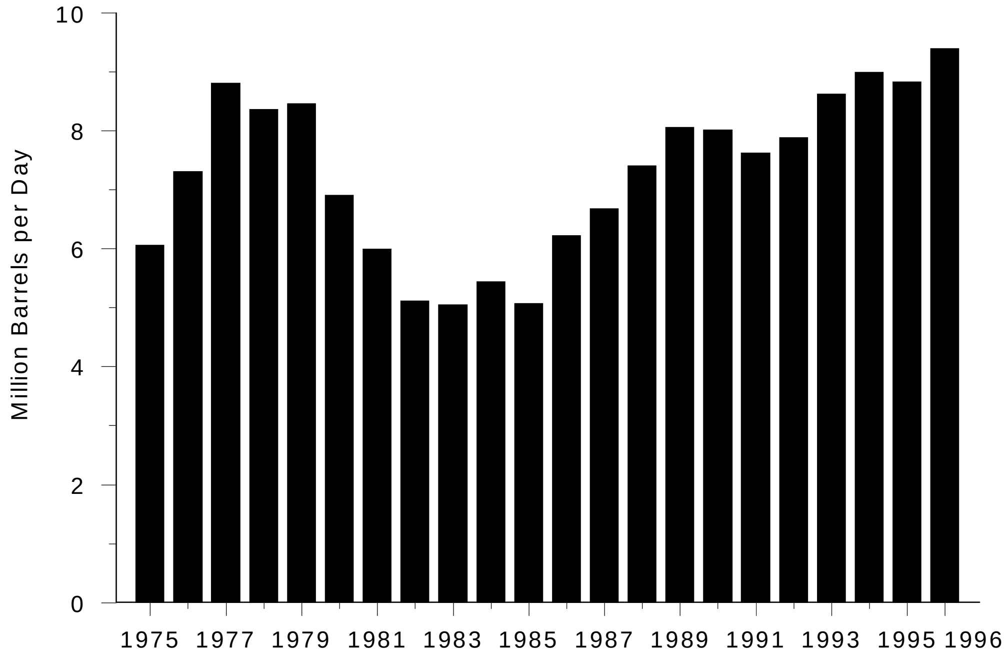
Net imports fill the gap between U.S. demand for oil and the country's capability to produce it. These swings in import levels are therefore driven by the relative swings in U.S. supply and demand.

U.S. Demand: Approaching Its Late 1970's Record High

Demand is the more variable of the two factors (Figure 51). It reached its all-time high of 18.8 million barrels per day almost 20 years ago, in 1978. By the early 1980's, it had plunged to 15.2 million barrels per day, but by last year, it had rebounded to 18.2 million barrels per day. This represents an increase of 3.0 million barrels per day, or 20 percent, over the mid-1980's low point, and a new peak in this current growth phase.

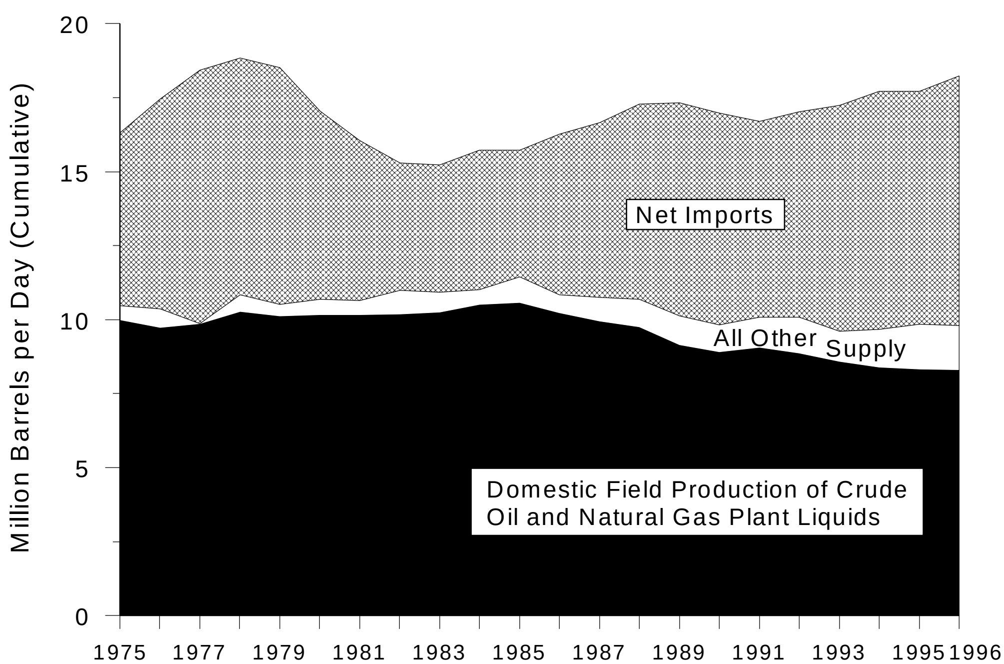
The primary driver for these oil demand swings over the last 20 years has been the level of economic activity, which is itself, in part, a function of oil prices. Each of the last three

Figure 50. U.S. Gross Oil Imports, 1975-1995



Sources: **1975-1980:** Energy Information Administration (EIA), *Petroleum Supply Monthly* (February 1993), Table S3. **1981 Forward:** EIA, *Petroleum Supply Monthly* (February 1997), Table S3.

Figure 51. U.S. Petroleum Supply and Demand



Note: All Other Supply includes refinery processing gain, unaccounted for crude, stock change, and field production of other hydrocarbons.

Sources: **1975-1980:** Energy Information Administration (EIA), *Petroleum Supply Monthly* (February 1993), Table S1. **1981 Forward:** EIA, *Petroleum Supply Monthly* (February 1997), Table S1.

U.S. recessions (1974-75, 1980, and 1991) was immediately preceded by a sharp increase in the price of oil that, in the latter two cases, was subsequently eroded. Oil use stumbled as economic activity dipped, and then subsequently recovered as the economy picked up speed again. Each time, the recovery in demand for oil was only partial, resulting in a steady loss of market share to other fuels that was not reversed until quite recently. These earlier losses and the current gain can be understood by dividing markets for oil into two categories — captive and multi-fuel — according to their vulnerability to substitution.

In the early 1980's, after two oil price shocks and fears of more to come, and after the decontrol of domestic oil prices, newly attractive alternatives like coal and nuclear were not just gaining a major share of the new multi-fuel markets, like power generation, but were also rapidly displacing oil from many of the existing multi-fuel markets. This further amplified the demand losses triggered by the 1980-82 recession. Gradually, this displacement pendulum lost momentum. With the capital investment made and with low operating costs, coal and nuclear could not easily be dislodged from their newly won markets, even when oil prices fell. But they have been making few new inroads. The trickle of ongoing gains has been centered on natural gas.

Captive markets are not immune to economic and price signals. However, devoid of ready alternatives, the oil demand elasticity of such markets is necessarily limited. For a period in the 70's and 80's, price signals and the introduction of more efficient vehicles significantly influenced the transportation sector (passenger cars, trucks, planes, trains, and buses) which currently accounts for over two-thirds of total consumption. This further contributed to the sharp downturn in oil demand in the early 1980's. But prices and price expectations receded, and many of the older less efficient vehicles have been replaced. Growth in the captive markets has reemerged, as can be illustrated by looking at gasoline, and there are no longer significant losses in the multi-fuel markets to mask it.

The CAFE (Corporate Average Fuel Efficiency) standards institutionalized fuel efficiency improvements for on-highway vehicles, helping reduce gasoline demand from a peak of nearly 7.2 million barrels per day in 1977 to 6.3-6.4 in the first half of the 1980's. But the momentum was not maintained. Today, Americans own more vehicles than ever, and with a greater proportion than ever being gas-guzzling sport utility vehicles and mini-vans. Since, headlines to the contrary, gasoline is cheap — 1996's average pump price, adjusted for inflation, was one of the lowest of the post-war period, and only about one-third of the price in Europe — Americans are also driving their vehicles further and faster. Gasoline demand therefore recovered to a new record high of 7.6 million barrels per day last year, 40 percent of total oil demand.

U.S. Supply: Gradual Decline from Its Early 1970's Peak

U.S. production of crude oil and natural gas plant liquids has been declining since the early 1970's from its 11.3 million barrel-per-day peak, despite temporary relief provided by the 1977 start-up of Alaskan North Slope production (centered on Prudhoe Bay, the largest field ever found in the U.S., with 12 billion barrels of recoverable reserves). The decline has occurred mainly because the U.S. is the most mature producing region in the world, with over three million oil and gas wells completed since the first was drilled in Pennsylvania in 1859. Given the declining resource base, domestic oil resources are in constant need of exploration and development to sustain production (see Chapter 3). Yet the U.S. has steadily been de-emphasized by many companies, as the rest of the world has opened up to upstream activity, providing more attractive investment opportunities.

However, with production still averaging 8.3 million barrels per day, the U.S. remains a world leader, second only to Saudi Arabia. With the breakup of the Soviet Union, Russia has dropped to third, and is struggling to stay within 2.0 million barrels per day of the U.S. level.

Oil production, which covers crude oil, condensate, and natural gas liquids, accounts for the vast majority (85 percent) of the 9.8 million barrels per day of domestic supply. The rest comes from a variety of sources, the most important of which is *processing gain*, the volume gain that occurs at refineries as crude is processed into a stream of products that have, on average, lower densities. The more complex the refining system is, i.e. the greater the proportion of light products it is able to make, the greater the processing gain. The U.S., with the largest and most complex refining system in the world, achieves a processing gain of 800 thousand barrels per day, which is over 8 percent of all domestic supply. Synthetic hydrocarbons, such as ethanol or MTBE, are another supply source, averaging 300 thousand barrels per day.

In total, these non-production sources of domestic supply averaged over 1.5 million barrels per day last year, more than three times their level in the mid-70's and mid-80's. Without this contribution, the decline in domestic supply and the growth in imports over the last decade would have been even more dramatic.

Outlook For Imports: More Growth, More Records

Now that substitution losses are offsetting so little of the growth in the captive markets, U.S. demand is moving back up toward its record high. By 1998, the EIA forecasts it will reach 18.6 million barrels per day, 0.4 million barrels per day higher than last year, and only 0.2 million barrels per day below the 1978 record.

Over the next couple of years, the non-production sources of supply are expected to grow more slowly, largely because there is now little regulatory incentive either to continue expanding oxygenate production or to upgrade aggressively (and thus boost processing gain). However, despite the growth in Gulf of Mexico flows, the decline in domestic production is expected to continue unchecked. Thus, the decline in total domestic supply will accelerate slightly, falling to 9.4 million barrels per day by 1998, the lowest level since 1965.

In the near term, with the expectation that consumption will continue to grow and that supply will continue to decline, there is only one direction for imports to go: up, to new record highs in terms of both volume and dependency. By 1998, EIA expects gross crude oil and petroleum product imports to breach the 10 million barrel a day level for the first time ever.

U.S. Import Dependency Is Modest in Global Terms

Figure 52 places the U.S. dependence on imports in a global context. Both world oil consumption and supply are displayed on a regional basis, with each region's "gap" indicating whether it is a net importer or exporter. To simplify, the U.S. has been combined with its two NAFTA partners, Canada and Mexico, to comprise North America (while also still being separately identifiable). These partners are two of the top oil suppliers to the U.S. The net import dependence for North America is therefore very much less than for the U.S. alone.

On a regional basis, North America is the number one consumer, as it has been for decades. Asia/Oceania has recently leapt into second place ahead of Europe, growing by 70 percent in ten years and even outstripping the U.S. in 1996. This alone would have pulled the center of gravity of world oil demand eastward, but this shift was given additional momentum by the unprecedented demand collapse in the Former Soviet Union (FSU). Demand there almost halved in the first half of the 1990's, falling by over 4 million barrels per day.

The picture for supply is in sharp contrast to that for consumption. North America is important, but the Middle East dominates the picture. The dominance would be even greater if the region's major producers were to use all their production capacity, as every other producer in the world does. Iraq cannot, because of the U.N. imposed embargo; a few others choose not to, limiting their production to their OPEC quota level instead. The Middle East's dominance has increased significantly over the last ten years, not only because production there has nearly doubled but also because of declines in both the U.S. and the Former Soviet Union (FSU). The latter is primarily one dramatic consequence of the delay in the FSU's attempted transition to a new political, economic, and social order. All the other regions have enjoyed growth, particularly those that have made the greatest efforts to attract private and foreign investment.

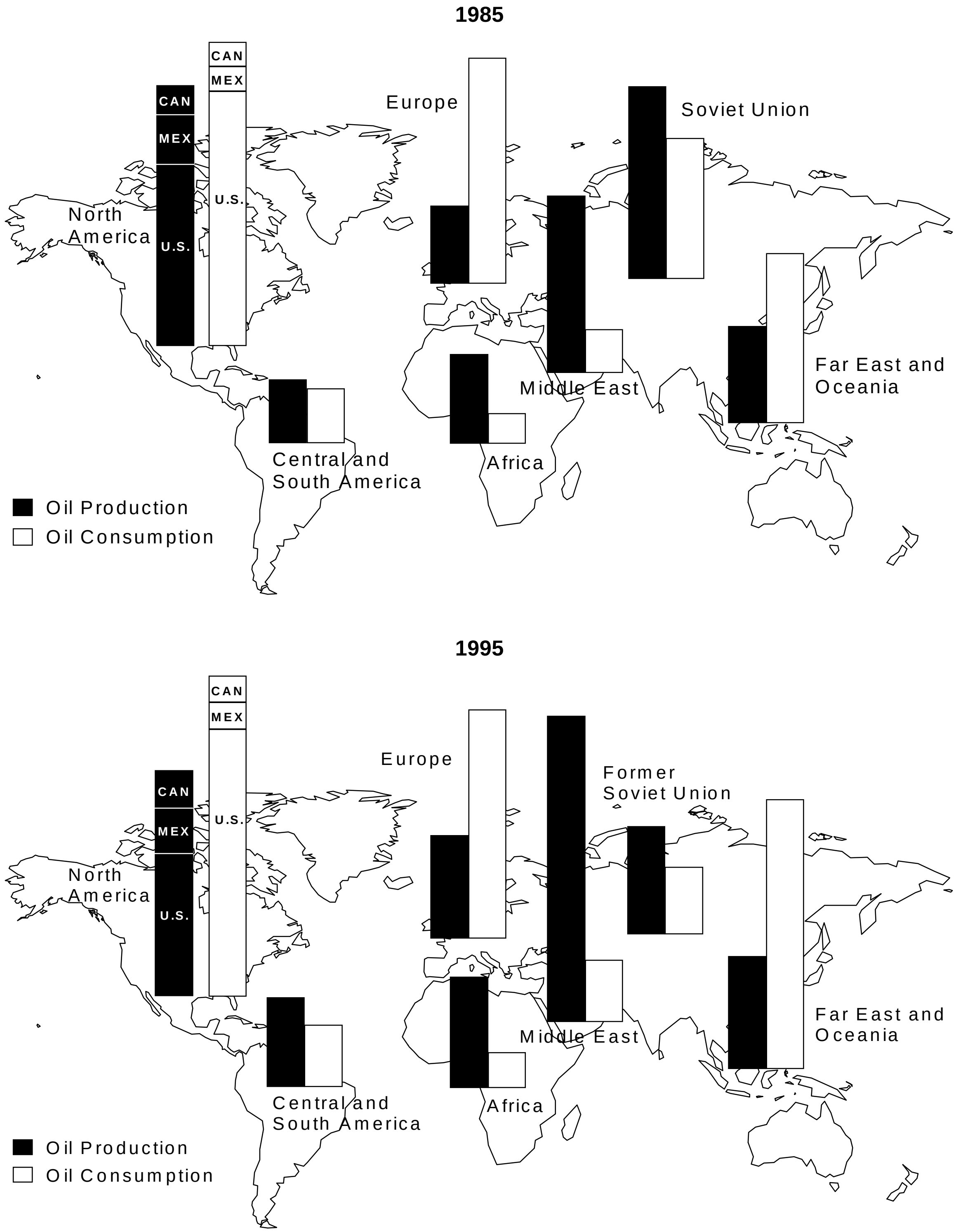
When the two parts of the regional balances are put together, it shows that all three main consuming regions are net oil importers, while all the major producing areas (except North America) are net exporters.

The honor of being the largest regional importer falls to Asia/Oceania. This region's net import requirement now exceeds over 10 million barrels per day, for an overall import dependency of over 60 percent. On both counts, it has greater import exposure than the U.S. However, the regional dependency is not really representative of any of the individual countries. A few, such as Indonesia, are net exporters; others, such as China, have just become net importers; most are almost totally import dependent. This latter group includes Japan, a very distant second to the U.S. in the rankings of consuming countries, using almost 6 million barrels per day.

Europe has the next highest need for imports. Unlike Asia/Oceania, its need has been declining, thanks to the tripling of Norway's production and, to a minor degree, Eastern Europe's demand collapse, and is now under 9 million barrels per day. But like Asia/Oceania, regional import dependency is an unrepresentative 60 percent. Most of Europe's production comes from the North Sea, shared between the U.K. and Norway. That leaves most European countries in a position similar to Japan's: almost entirely dependent on imports.

Thus, although U.S. oil imports are an important force in the world oil trade, they do not constitute an unprecedented regional flow. Also, U.S. oil import dependency is much less than that of most of its major allies, who tend to be less well endowed geologically.

Figure 52. Regional Supply and Demand Balance, 1985 and 1995



Notes: Oil production includes crude oil, natural gas plant liquids, other liquids, and refinery processing gains. Oil consumption includes internal consumption of all refined products, refinery fuel and loss, and bunkering.

Sources: **1985:** Energy Information Administration (EIA), *International Energy Annual 1986* (October 1987), pp. 30-31. **1995:** EIA, *International Energy Annual 1995* (December 1996), pp. 5-7 and 207-209.

Crude Oil Dominates U.S. Imports

The U.S. imports both crude oil and products. Crude oil has consistently dominated the flows (Figure 53). Last year, crude oil accounted for 80 percent of all U.S. oil imports, averaging 7.5 million barrels per day.

This preference for crude oil in part reflects history. The domestic refining industry has long-established roots because the U.S. was one of the pioneers of the modern oil era, with enough crude oil of its own to be a net exporter for the first one hundred of its one hundred and fifty years as a producer. It also reflects the basic economics of the industry worldwide: it is generally more cost-effective to refine products close to the point of consumption. This is confirmed by the composition of world trade in petroleum: 80 percent by volume is crude (and the share is even larger in ton-mile terms). Governments also often intervene in the market to swing the economics even more in favor of domestic refining, justifying it as enhancing supply security.

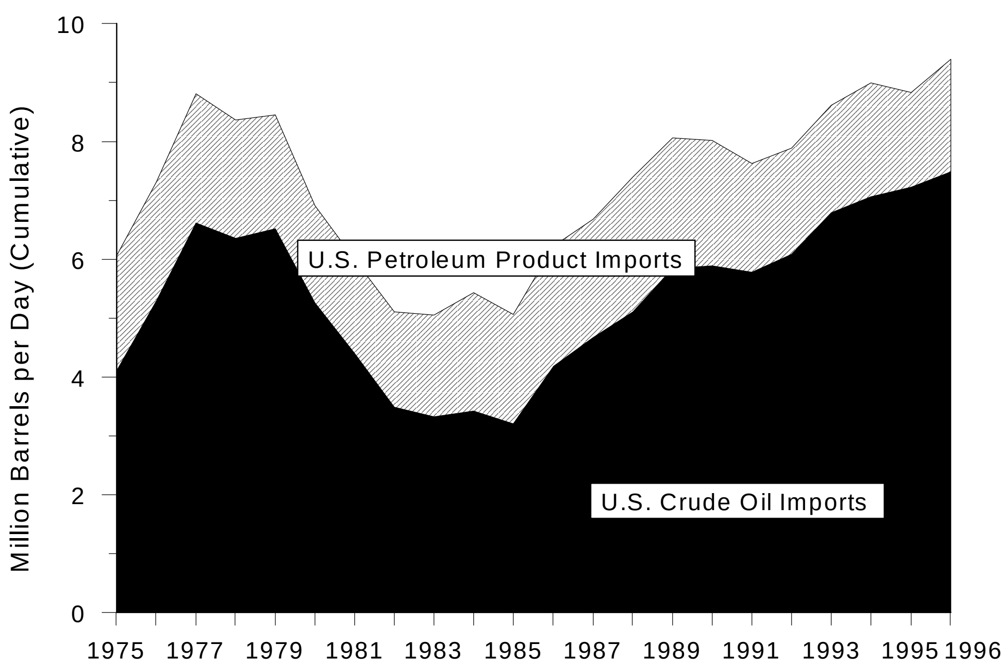
The growth of crude imports over the last decade sharply underscores the incentive for U.S. refiners to maximize runs, particular since there have been no new, "grassroots" refineries built in the Lower-48 during this period. Runs were raised through a combination of refinery restarts, expansions, debottlenecking, and improved operating practices such as extending the time between turnarounds.

Product imports primarily play a balancing role in world oil markets, with their flows varying depending on factors like weather, refinery turnarounds, or accidents. They can also be the consequence of local resistance to refineries. The U.S. East Coast provides one of the clearest examples of this. It refines only one-third of the products it consumes. To fill the gap, it takes products from other regions while also importing three-quarters of all the finished products coming to the U.S.

As would be expected from the foregoing, crude has borne the brunt of the swings in U.S. imports over the last twenty years, but its share has never dropped below 60 percent. Between the mid-1980's low in total imports and last year, total crude oil imports increased by over 4.0 million barrels per day while product imports increased by less than 100 thousand barrels. Ranges better capture the volatility of imports, particularly of products. Even so, they show product flows varying between 1.6 and 2.3 million barrels per day during the last twenty years, while crude varied between 3.2 and 7.5 million. Crude's variability has been six times that of products.

Some of the main characteristics of product imports are highlighted in the box on p. 71. The rest of this chapter concentrates on crude oil.

Figure 53. Crude Oil Dominates U.S. Imports

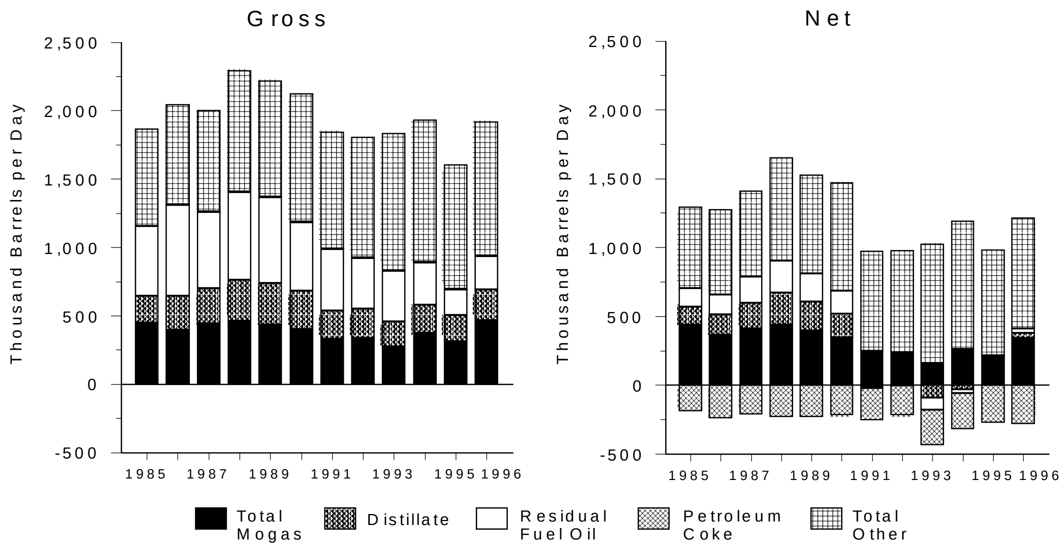


Sources: **1975-1980:** Energy Information Administration (EIA), *Petroleum Supply Monthly* (February 1993), Table S1. **1981 Forward:** EIA, *Petroleum Supply Monthly* (February 1997), Table S1.

Product Imports

Product imports have followed a very different trend from crude imports in the last decade. They rose to a peak of 2.3 million barrels per day in the late 1980's as U.S. refiners struggled to keep up with the rapid growth in oil consumption, particularly of light products. They then slipped back, undermined first by the 1990/91 recession and then by the surge in refinery upgrading capacity that resulted largely from the requirements for cleaner fuels in the Clean Air Act Amendments (1990) and other environmental legislation. Aided also by steadily increasing refinery utilization rates and by the growth in production of synthetic hydrocarbons, like MTBE, domestic production has met a growing percentage of U.S. oil demand. The low point for product imports was reached in 1995, when imports dipped to 1.6 million barrels per day, undermined by the fierce inter-fuel competition that drove residual fuel oil demand to a post World War II low. In 1996, product imports recovered to 1.9 million barrels per day, in line with 1991-1994, but only slightly higher than 1985's level.

U.S. Gross and Net Product Imports, 1985-1996



Over the same period, product exports took another step up. Until the early 1980's, they consisted primarily of petroleum coke, since most other products were tightly regulated. As export license requirements were eliminated, exports started to grow. Light product exports received a particularly strong boost after Iraq's destruction of Kuwait's refining capacity in 1990 led to a significant shortfall of products into Asia, just as oil demand there started to soar. U.S. exports of both gasoline and distillate doubled. Even though Kuwait's capacity has been fully restored, the higher export levels have been sustained. Having had a crash lesson in how to export such products successfully, and having experienced no political backlash, U.S. refiners and marketers now move their surpluses to whichever overseas market is most attractive at a particular time. Thus, distillate exports to western Europe averaged less than 5 thousand barrels per day during the first eight months of 1996, but jumped to about 80 thousand barrels per day in the final four, when the trans-Atlantic arbitrage window was wide open.

As a consequence of these two disparate trends, net product imports in 1995 were less than half their 1988 peak of 1.6 million barrels per day. Net imports have declined for all main products, but most notably for distillate where, in a break with the past, the U.S. has been theoretically self-sufficient in distillate since 1991, i.e. net imports have been approximately zero. The overall downtrend was reversed in 1996 when, aided by the exceptionally cold 1995-1996 winter and by the European gasoline glut, net product imports jumped back up over 1 million barrels per day. Capital investment in the refining sector is expected to slow, now there is a lull in environmentally-driven, mandated investment, leaving domestic refiners unable to keep pace with the expected growth in consumption. Thus, further increases in net product imports are expected over at least the next few years.

The reduction in net imports has been another negative for the U.S. refining sector because it has undermined margins. Price in an importing region is the balancing market price plus transportation. In an exporting region, it is that price minus transportation. As imports shrink, their balancing, or price-setting, market moves closer; as exports grow, theirs moves further away. In each case, this reduces the relative price in the price-taking market. This is what has been happening in U.S. main product markets over the last few years. For example, in the late 1980's, imports of distillate reached about 300 thousand barrels per day, and came from a wide variety of sources. Now, imports have dropped by about a third, to around 200 thousand barrels per day, with 90-95 percent coming from just three nearby locations: E. Canada, the Virgin Islands, and Venezuela. Simultaneously, exports have doubled, also to around 200 thousand barrels per day, with a significant proportion of Gulf Coast volumes having to go as far as Asia. Consequently, both Gulf coast and East Coast distillate prices are lower relative to the world market, and to crude, than they would have been if there had been no change in product flows.

An Overview of Crude Oil Imports

Imports of crude oil have grown dramatically since the mid-1980's, when domestic crude production began its most recent decline phase. Crude oil now accounts for over 80 percent of total petroleum imports.

Imports Have Set Four Consecutive Record Highs...

U.S. gross crude oil imports averaged 7.5 million barrels per day last year, the fourth consecutive record high (Figure 54), and the third consecutive year that they have exceeded domestic crude production. This puts crude imports more than 1.0 million barrels per day above the prior cycle's 1977 peak of 6.6 million, and 4.5 million above its 1985 low.

Back in the late 70's and early 80's, crude oil imports received a boost of about 150 thousand barrels per day from the building of the Strategic Petroleum Reserve (SPR). There have not been any imports for the SPR for nearly three years now. The government has recently started to sell limited volumes of SPR oil for both operational and fiscal reasons (see Chapter 5).

U.S. crude flows are not entirely one way. Exports occur, but are just a fraction of imports because they are largely precluded by highly restrictive regulations. Exports mainly consist of Alaskan North Slope crude delivered to U.S. possessions and territories, particularly the Virgin Islands. Because of these exports, U.S. net dependency on the global crude oil market has been 1-2 percent lower than its gross dependency.

... And Will Continue to Increase

Total U.S. imports will continue to grow in the near term, increasing by around 900 thousand barrels per day over the next two years. As in the past, most of this increase will be crude — over 80 percent for this period. Thus, the rate of growth of crude imports will be slower than over the last decade, but the average annual volume increment will be higher. Both gross and net crude oil imports will continue to set new record highs.

As domestic crude production continues to decline, more questions are being asked about the appropriateness of existing marker crudes[24] for the U.S., particularly inland ones like West Texas Intermediate (WTI). Will rising imports present new alternatives? Many imported crudes, like those from Saudi Arabia, Mexico, and Venezuela, are hamstrung by resale restrictions, so growth in their flows will not increase liquidity in the Gulf Coast crude market. Colombia's Cusiana crude seems a possibility on the face of it, with volumes expected to jump to 450 thousand barrels per day before the end of 1998, with the U.S. being its target market, and with the equity owners willing to trade. Cusiana's big drawback is the proven vulnerability of its export pipeline to guerrilla attacks and, therefore, repeated force majeure. The best alternative may lie even closer to home in the rapidly rising flows from the Gulf of Mexico, typified by the sour Mars Blend stream.

[24]A marker crude is one used as a basis for the pricing of other crudes.

Sources Of U.S. Crude Oil Imports

Economics drive the flow of crude oil — unless there are political constraints such as embargoes. A crude flows first to its most profitable market, the one that nets back the best value. Then, as volumes grow, it spreads out to steadily less profitable markets. Logistics are one of the prime determinants of such profitability rankings. Thus, crude tends to be sold to nearby, or short-haul, markets first, and then to progressively more distant, or medium- and long-haul, markets, other things being equal.

Short-haul Crudes Now Dominate

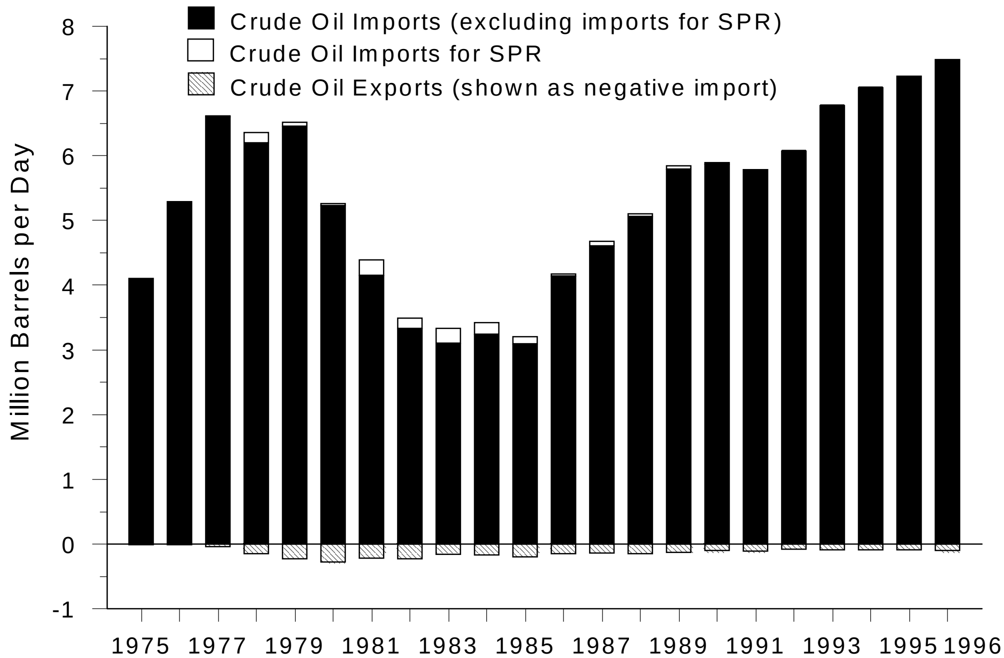
Figure 55 shows the main flows of crude into the U.S. in 1996, with the width of the arrows proportional to the annual volume on any given route. All these flows move by tanker, with the exception of Canadian imports, which move by pipeline.

Short-haul imports, defined here as those from Canada, Mexico, and Central and South America, clearly dominate, accounting for 4.0 million of the total 7.5 million barrels per day. This is the first time ever that the U.S. has obtained the majority of its crude from the Western Hemisphere.

The Crude Mix Used To Be Different

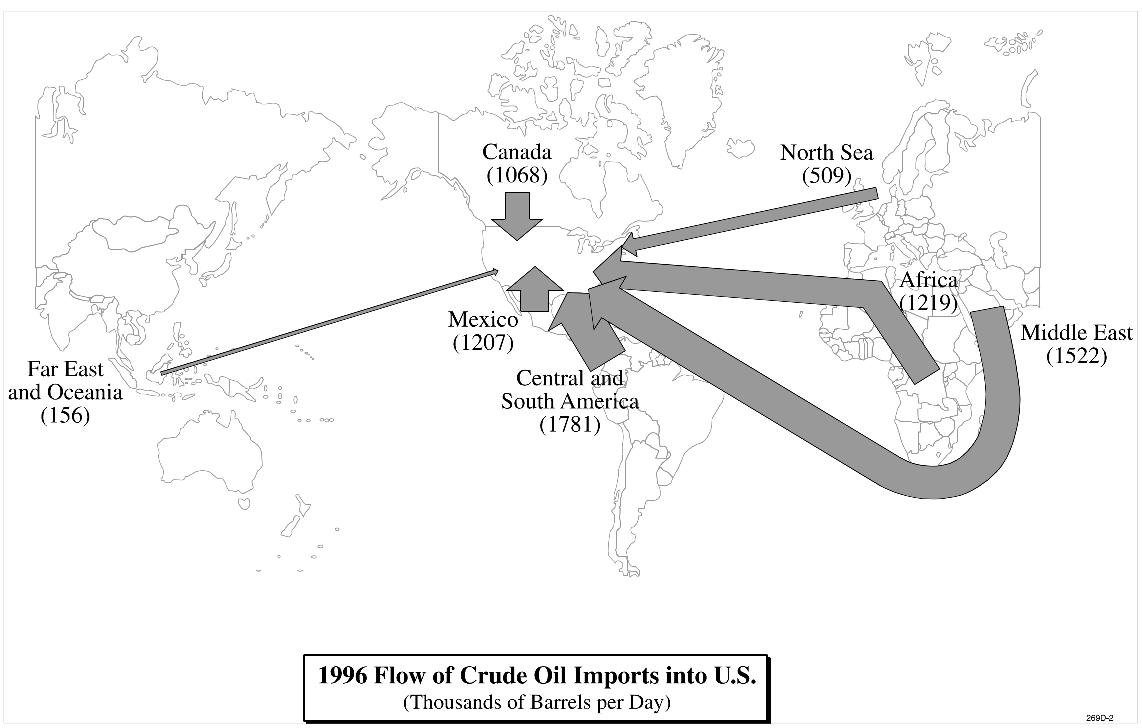
The mix of supply sources for U.S. crude oil imports has changed significantly as volumes have risen, shifting away from regions frequently cited as politically unstable (Figure 56). Some have concluded that this makes the U.S. less vulnerable to price shocks. It is important to understand, though, that it is not the degree of U.S. dependence that will determine the impact on price of any disruption in a

Figure 54. U.S. Crude Oil Imports: Net and Gross



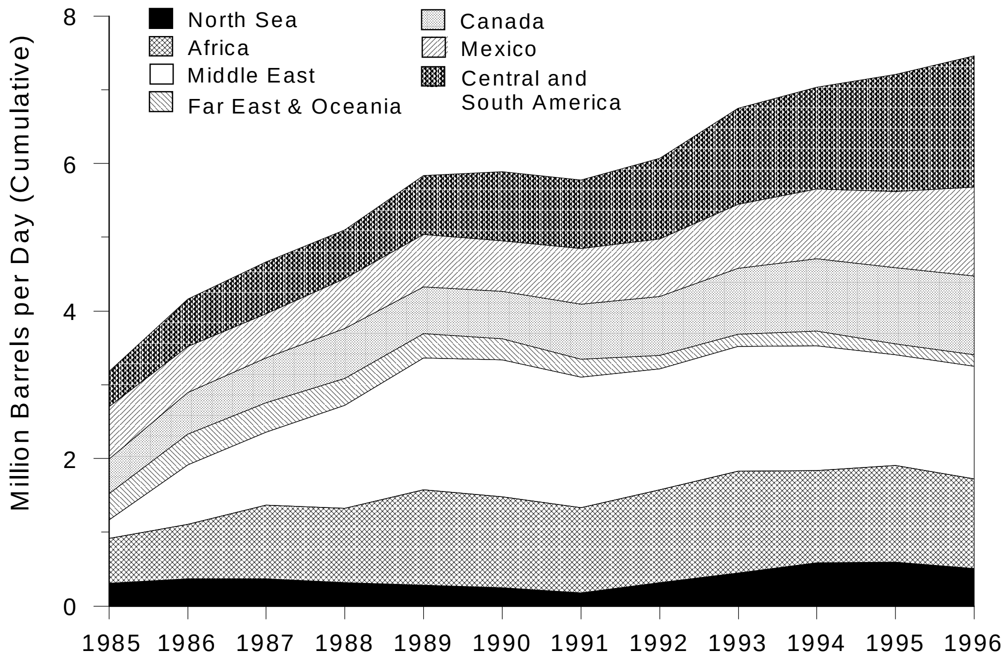
Sources: **1975-1980:** Energy Information Administration (EIA), *Petroleum Supply Monthly* (February 1993), Tables S1 and S2. **1981 Forward:** EIA, *Petroleum Supply Monthly* (February 1997), Tables S1 and S2.

Figure 55. Origin of U.S. Crude Oil Imports, 1996
(Thousands of Barrels per Day)



Source: Energy Information Administration (EIA), Form EIA-814 data.

Figure 56. Changing Regional Patterns for U.S. Crude Oil Imports



Source: Energy Information Administration (EIA), derived from Form EIA-814 data.

particular region. Rather, it is that region's role in the global market.

Only one major region supplies less to the U.S. than it did in the mid-80's: the Far East & Oceania. This reflects the increased refining flexibility that has made the West Coast less reliant on the high quality crudes that are characteristic of this regional source, together with the increased willingness of integrated companies to optimize their crude slates on a global basis, and not just within their own company systems.

One of the most significant developments in the 1990's has been the decline in importance of Middle East crudes to the U.S. market. They were the fastest growing import stream between 1985 and 1990, rising to account for nearly one-third of all U.S. crude oil imports. The consensus view was that this share would continue to grow. Not only has the share declined, to just 20 percent in 1996, but the absolute volume has declined too.

Politics have played a role in this. Since mid-1990, Iraqi exports have been subject to a near total global embargo, only partially lifted in December 1996. Also, the U.S. has maintained a unilateral embargo on Iranian crude that dates back to October 1987. These limit the possibilities for Middle East crudes coming to the U.S. But the role of politics in determining the crude mix should not be overemphasized. It has been subsidiary to the main issue, which is the establishment of a new paradigm for the upstream sector of the oil industry.

Thanks to the aggressive implementation of new technology, the radical restructuring of operating practices, and the almost universal opening up of the upstream,[25] the global crude oil supply curve has been shifted significantly to the right, i.e., the volume of crude that can be economically produced at a given price has risen. Hence, despite prices that have been lower than were expected from the viewpoint at the end of the 1980's, OPEC, and most particularly its Middle Eastern members, have been called on to produce much less in the 1990's than was then expected because production almost everywhere else has soared.

Therefore, the sources of short-haul crudes have enjoyed rising production that has left them able to increase exports, and their preferred target, logically, has been the U.S. Latin America has been the star performer, with imports to the U.S. growing by 1.4 million barrels per day since 1990. All the medium and long-haul exporters to the U.S. market have lost ground to some degree. It has been particularly hard for

[25]Opening up of the upstream refers to the broad-ranging political, economic, institutional, and contractual changes that have occurred in virtually every oil-producing nation making their oil resources increasingly accessible to world oil markets.

the Middle East to compete because its crude is of the same quality, heavy sour, as the majority of short-haul grades. The less voluminous, light, sweet, short-haul grades, such as Olmeca (Mexico) and Cusiana (Colombia), have been partly responsible for the North Sea and Africa's shrinking share of U.S. crude imports in the last few years.

These changes in the long-haul/short-haul mix of imported crudes tend to lower the volume of stocks held onshore in the U.S. Firstly, a just-in-time inventory strategy argues for lower stocks if a supply source is nearer – a somewhat specious argument, perhaps, if those suppliers are already producing at maximum, have no buffer stocks themselves, and have a history of interruptions. Secondly, parcel sizes for short-haul crudes are generally smaller than those for long-haul crudes, meaning more frequent deliveries and a lower average stock level (see Chapter 5).

Six Countries Supply 80 Percent of U.S. Crude Imports

Not all countries in a region are the same, at least from the standpoint of being crude suppliers to the U.S. market. U.S. import dependency is much more concentrated than the regional analysis might suggest (Table 5).

The U.S. gets almost two-thirds of its crude oil imports from just four countries, each of which supplied over 1.0 million barrels per day last year: Canada, Mexico, and Venezuela, all short-haul sources, and Saudi Arabia, a long-haul source. Adding in the next two in the rankings, Nigeria and the North Sea (really Norway and the UK, but generally counted together in oil supply terms), takes the proportion up to 80 percent. The remaining 20 percent is split between 32 other countries.

It is more than just physical closeness and geology that has made the three leading short-haul suppliers so dominant. Firstly, Canada has no viable export market other than the U.S. Secondly, both PDVSA, and, more recently, Pemex (respectively the Venezuelan and Mexican national oil companies) have shrewdly invested via joint ventures in increasing the complexity of U.S. refineries. By enlarging the nearby, higher valued market for their poor quality crudes — referred to as increasing their fungibility — Venezuela and Mexico have leveraged the value of large segments of their crude production.

There are several reasons why Saudi Arabia, alone among long-haul suppliers, has been able to remain a significant exporter to the U.S. market, including:

- sheer size — the world's largest importer and the world's largest exporter want to do business together;
- the historic links between Saudi Arabia and the ex-Aramco partners: Mobil, Chevron, Exxon, and Texaco (see also Figure 62);
- ongoing embargoes of two of its Middle East rivals, and
- its transformation into a short-haul source for many of its U.S. customers by using the Caribbean as a transshipment center, and selling FOB out of there.

This last strategy has two side benefits. Saudi Arabia benefits because it raises the netback value of its sales in a backwardated market, the prevailing condition of the last couple of years (see chapter on futures). Its customers benefit because Saudi Arabia is, in effect, now holding some of their operating stocks in the Caribbean, reducing their working capital needs and reducing onshore U.S. stocks in the process (see chapter on stocks).

Where In The U.S. Does the Imported Crude Oil Go?

Every region in the U.S. imports some crude oil, but the regional similarities tend to end there because the different regions have distinctly different crude oil needs and choices.

Crude Oil Import Dependency Varies Regionally

The U.S. regional crude oil supply/demand balances are far from homogeneous (Figure 57). At one extreme is the East Coast, the most supply deficient of all the regions, which refines much less than it consumes. It is also dependent on imports for almost all the crude it runs. At the other extreme is the Gulf Coast, with substantially more refinery capacity than needed to meet its own consumption. It is the country's swing refining region, sending its surplus to fill in deficits elsewhere, mainly on the East Coast and in the Midwest.

One of the few common threads between the regions is that, to a greater or lesser degree, they all import crude. The Gulf Coast imports the most, receiving 4.3 million barrels per day last year, almost 60 percent of the total. Next comes the Midwest, closely followed by the East Coast. Both take less than a third of the Gulf Coast volume.

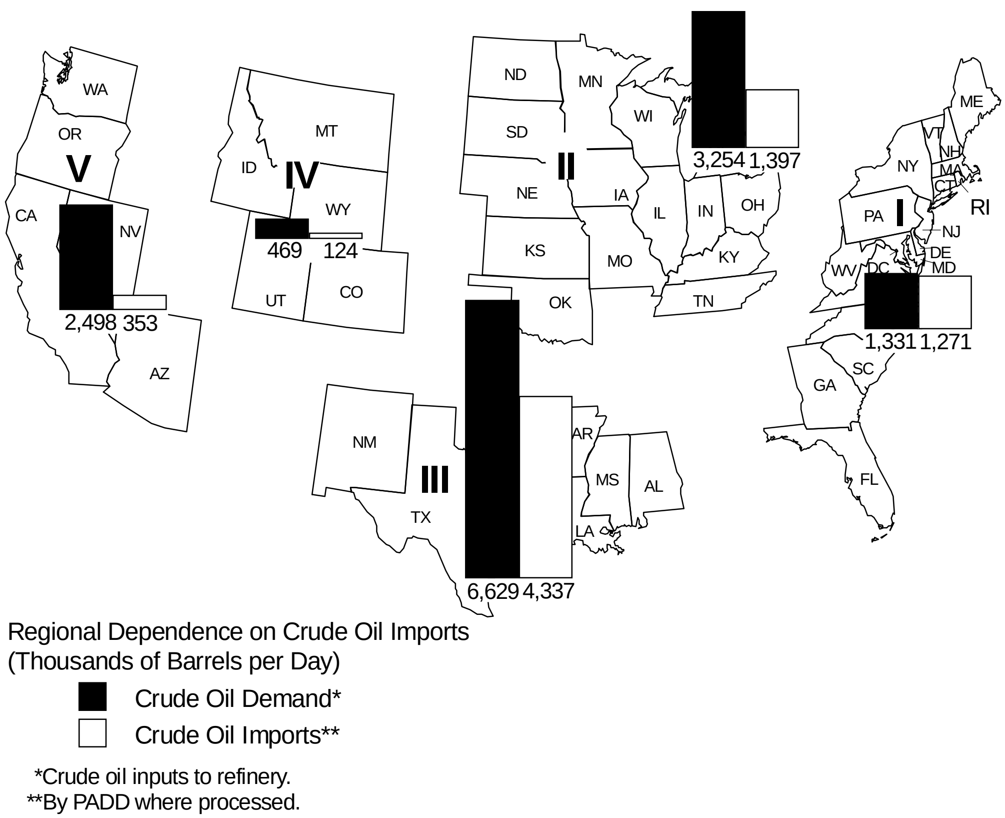
The Gulf Coast's role in crude oil imports is even larger than these data imply because, except for flows from Canada, all of the Midwest's imports move via the Gulf Coast, using the same ports and some of the same distribution infrastructure as the volumes that the Gulf Coast refines itself. Last year,

Table 5. The Top Six Sources of U.S. Crude Oil Imports, 1996
(Thousand Barrels per Day)

Year	Venezuela	Saudi Arabia	Mexico	Canada	Nigeria	North Sea	Rest of the World	Total
1985	306	132	715	468	280	309	991	3,201
1986	416	618	621	570	437	370	1,145	4,178
1987	488	642	602	608	529	374	1,432	4,674
1988	439	902	674	681	607	316	1,489	5,107
1989	495	1,116	716	630	800	278	1,808	5,843
1990	666	1,195	689	643	784	250	1,668	5,894
1991	668	1,703	759	743	683	180	1,044	5,782
1992	826	1,597	787	797	665	319	1,091	6,083
1993	1,010	1,282	863	900	722	449	1,561	6,787
1994	1,034	1,297	939	983	624	586	1,600	7,063
1995	1,151	1,260	1,027	1,040	621	599	1,533	7,230
1996	1,305	1,248	1,207	1,068	592	509	1,553	7,482

Source: Energy Information Administration, *Petroleum Supply Monthly* (February 1997), Table S3.

Figure 57. U.S. Regional Dependence on Crude Oil Imports, 1996



Source: Energy Information Administration (EIA), derived from Form EIA-814 data.

almost 600 thousand barrels per day of crude moved to the Midwest this way.

Crude Imports Have Shifted East and South Since the 1970's

The pressure the record high U.S. crude import level puts on different regions varies (Figure 58). Three regions still lag their prior peaks, all of which were set in the late 1970's. The West Coast has the most leeway; only importing one-third of its 1977 pre-Prudhoe Bay level of 1.1 million barrels per day last year. Declining production and rising throughput have pushed the Midwest to within sight of its 1977 peak, while the restart of Tosco's Trainer Refinery in Philadelphia in mid-1997 could be enough to take the East Coast to new highs. But it is PADD III, the Gulf Coast, and to a lesser degree PADD IV, the Rocky Mountains, that have already been presented with new challenges from record import flows.

Well before even the current levels of crude oil imports were reached in these two regions, concerns were being raised about the adequacy of both the ports and the pipeline systems to handle the flows. The reality has been that the infrastructure has shown an unprecedented degree of flexibility. Pipelines have been reversed (Mobil), debottlenecked (Arco), extended (Diamond Shamrock), built (Express), newly connected (Amoco), or even switched from natural gas to crude oil service (Seaway). While getting sufficient crude supply to the U.S. might at times be a legitimate concern, handling it once it reaches the U.S. should not be, barring accidents.

Quality Issues

Crudes are not all alike. They differ considerably in their physical properties, with the important differences being the proportions of the various hydrocarbon fractions that can be turned into the different products and the levels of various contaminants, such as sulfur or metals. These properties affect the ease with which refiners can process various crude oils into the different products required by consumers. The two physical properties that are most often quoted for crude oil are:

- API gravity, which is a measure of a crude oil's density or specific gravity. A high gravity crude is 'light' and a low gravity one is 'heavy'. Other things being equal, a light crude yields more light products than a heavy crude.
- Sulfur content, which measures a crude oil's sulfur by percent weight. A low sulfur crude is 'sweet', and a high sulfur one is 'sour'. Sulfur is a pollutant. Its level in finished products is increasingly being limited in the U.S., mostly by Clean Air Act regulations.

Crude Oil Values Vary Directly with Quality

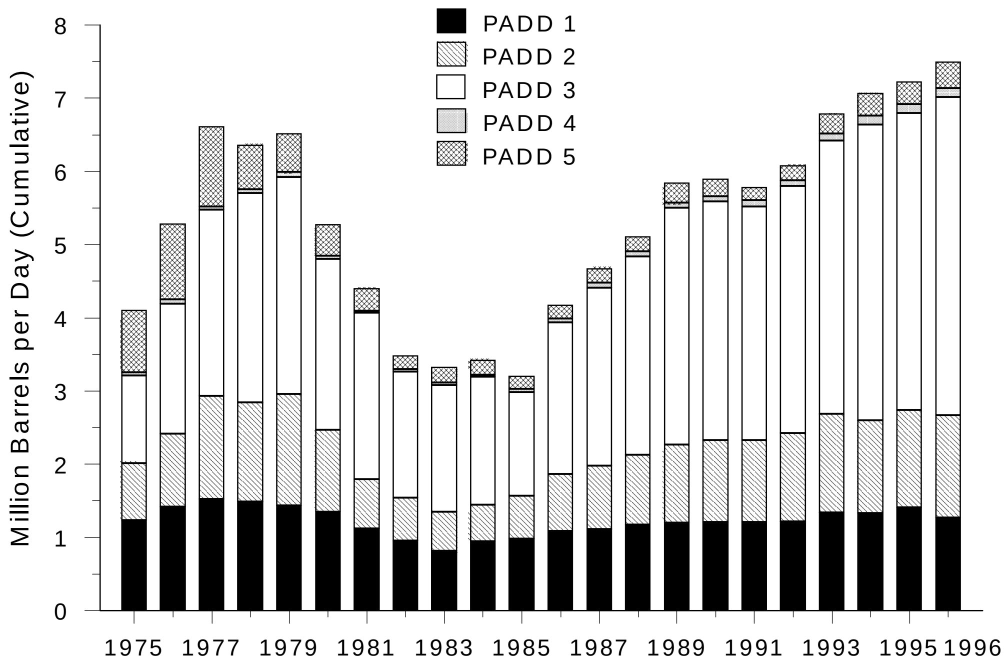
A refiner is interested in a crude for the value of the products it yields. His aim is to turn the crude into as much of the lighter, higher priced products and as little of the heavier, lower priced products as is cost-effectively possible. In the U.S. market, that usually means maximizing gasoline while minimizing the residual fuel oils and other residues that sell for less than the price of the crude.

Refineries, like crudes, differ. A simple refinery produces products that reflect the natural characteristics of the crude. As a refinery becomes more sophisticated, it produces more light ends and less residual oil, because the heavier materials are reprocessed into feedstocks for additional, and generally high capital investment, processing units.

The yield, or mix, of products a refiner produces therefore depends on his choice of crude and the operating configuration of his refinery. Thus, taking value as the aggregate revenue from the products produced from the crude less the cost of refining it, different crudes can have different values for the same refiner, while the same crude can have different values for different refiners. (Note: in choosing which crude to buy, a refiner would need to compare this value with the delivered cost of the crude to calculate its marginal value, and rank the results.) In general, light crudes are more valuable than heavy ones, and sweet crudes more valuable than sour. These quality differentials, or differences in value between light and heavy, and between sweet and sour crudes, vary between refiners, between regions, and over time (see Chapter 7).

Hence quality, like logistics, is a prime determinant of crude flows. The demand curve for a particular crude therefore varies as both the transportation cost and the quality differential vary, making the curve non-linear with respect to logistics. In other words, to progressively place a crude, a producer can be moving back and forth between closer and more distant markets, depending on the relative trade off between the cost of transportation and the quality premium for the crude in each market at that time. The resultant market clearing price will not necessarily be set either in the same market each time, or in the most distant market that takes the crude.

Figure 58. U.S. Regional Dependence on Crude Oil Imports Over Time, 1975-1996



Sources: **1975-1980:** Energy Information Administration (EIA), Energy Data Reports, Petroleum Statement Annual. **1981-1995:** EIA, *Petroleum Supply Annual* (February 1997), Table 34.

Imports Are Poorer In Quality Than Domestic Crudes

Refiners aim to find the most cost effective way to meet demand within the constraints of their own facilities. As the U.S. refining system is the most complex in the world, and as U.S. crude quality is better than the world average, it is hardly surprising that imported crudes lower the quality of the crude slate that U.S. refiners run (Figure 59). This deterioration is particularly pronounced for sulfur, with imports having double the unusually low level in domestic crudes.

The West Coast is the only region where imports do not reduce the quality of the crude slate. The quality of its own production is very much worse, at 24 degree API and 1.2 percent sulfur, than that in any other region in the U.S. It has therefore long imported crudes toward the high end of the quality spectrum, pulling its quality average closer to the U.S. norm. Historically, these crudes generally came from Asia, particularly Indonesia and Malaysia. Over time, the West Coast refiners upgraded, lessening their need for such extremely light sweet crudes. An increasingly large proportion of their imports then gradually shifted toward Alaskan North Slope 'look-alike' grades, to give themselves purchasing leverage in an oligopolistic market for a crude whose production was steadily declining.

On a simultaneous gravity and sulfur ranking, PADD III imports the worst crudes. A major influence here are the joint venture investments that heavy crude producers like Venezuela and Mexico have been successfully pursuing to improve the fungibility of their crudes in U.S. markets. Their main target has been the Gulf Coast.

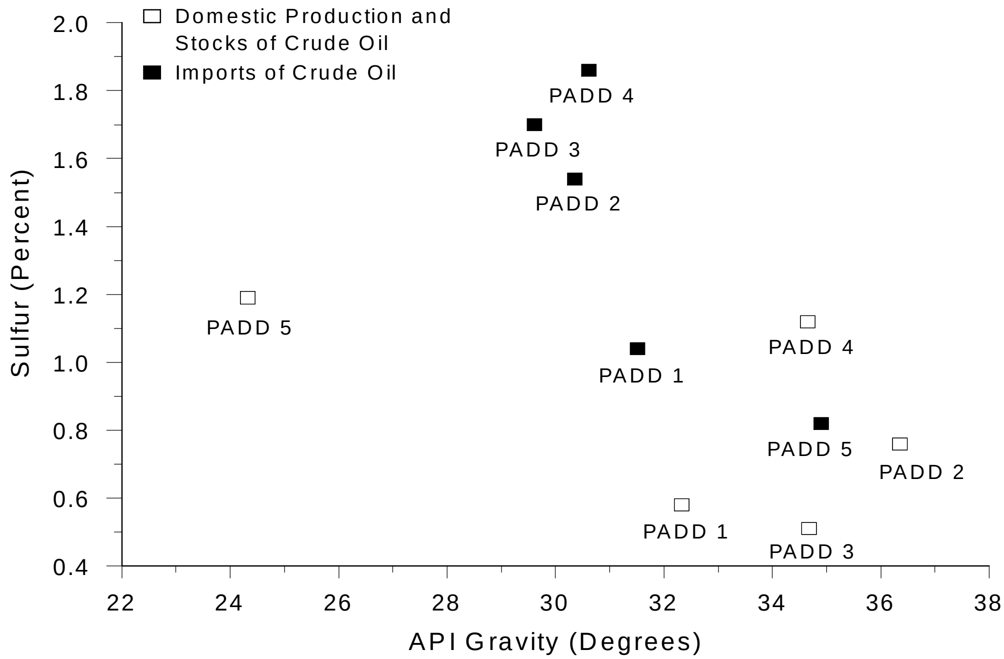
PADD IV, the Rocky Mountains, comes a surprisingly close second, considering it is a market dominated by smaller, niche refineries. Logistics make Western Canada its preferred — and, currently, its only nondomestic — crude supplier. As production there got heavier, the economic imperative to upgrade became overwhelming for the Rocky Mountain refiners accessing those crudes.

Different Regions Supply Different Quality Crudes

U.S. crude oil imports fall into two clear quality groups, sweet and sour (Figure 60). Canada, Mexico, Venezuela and Saudi Arabia supply the poorer quality, sour, predominantly heavy grades, while the North Sea, Africa, and the rest of Latin America supply the better quality, sweet, frequently light grades.

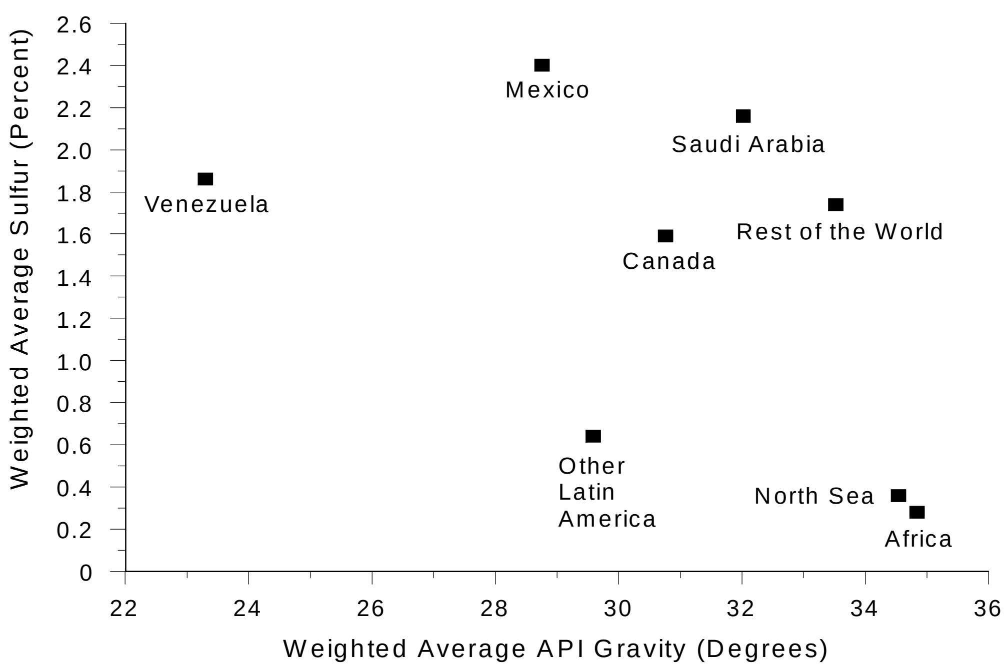
There is strong competition between suppliers within each of these two groups, with logistics generally being the deciding

Figure 59. A Comparison Between Imported and Domestic Crude Oil Quality in 1996



Sources: Energy Information Administration (EIA). **Imports:** derived from Form EIA-814 data. **Domestic:** derived from Forms EIA-810 and EIA-814 data.

Figure 60. The Quality of U.S. Crude Oil Imports by Supply Region, 1996



Source: Energy Information Administration (EIA). Form EIA-814, with imputed values for 1 to 4 percent of data.

factor between winners and losers. Saudi Arabia's competitive disadvantage in the sour group has already been noted. In the light sweet group, the competitive disadvantage, vis-a-vis the U.S. market, lies with the African producers, particularly West African countries like Nigeria and Angola. Of course, these countries have a competitive advantage over the North Sea vis-a-vis the Asian market. This has made them the swing source for the world light, sweet crude market, just as the Middle East is for the heavy, sour market. West African crudes are now routinely pulled or pushed between the Americas and the Far East, depending on the relative strengths of their respective markets. This competition is reflected in the price of Asian quality crudes relative to Brent, which depends on many factors, including the time of the year, accidents at refineries or oil fields, and the pace of tightening quality standards.

There is also competition between the quality groups. This influences, and is influenced by, the level of the quality differentials. This competition has contributed to the changing quality of U.S. imports over time.

The Quality of U.S. Imports Has Deteriorated

The quality of U.S. crude imports today is lower than it was in the mid-1980's, as is the quality of U.S. refinery runs as a whole (Figure 61). This is mainly the result of aggressive capital investment by the U.S. refining sector that has raised the complexity of the whole system and made it capable of running a higher proportion of poorer quality crudes despite a lightening of the mix of products being consumed and a tightening of product quality standards. But why did U.S. refiners choose to do this?

- The U.S. is the world's leading importer. Its refiners need flexibility if they are not to be held hostage by suppliers, particularly in the light of two trends that have long been expected to prevail: that U.S. imports will continue to grow, and that world crude quality will deteriorate (an expectation that has not always been fulfilled).

- U.S. demand is significantly more skewed to light products, especially gasoline, and away from residual fuel oil, than the norm elsewhere in the world. Refiners therefore have a relatively greater economic incentive to invest aggressively in residual destruction units.

- Environmental legislation, such as the 1990 Clean Air Act Amendments, effectively forced investment in upgrading. The marginal cost of adding upgrading capability beyond that required by cutting edge U.S. environmental restrictions has been frequently relatively low. Venezuela and Mexico actively sought joint venture upgrading investments in the U.S. market.

This upgrading allowed the short-haul suppliers to win an even larger share of the U.S. market, by allowing them to compete successfully with suppliers of light sweet crudes, like Africa. Thus the observed swing in the U.S. from medium and long-haul toward short-haul crudes was not purely the result of logistics.

Most of the deterioration in import quality had occurred by the early 1990's. The subsequent leveling off came about largely because the quality of the crude being produced worldwide improved, due to a major production shift by Saudi Arabia from its medium and heavy to its lighter grades, coupled with the geologic coincidence that the surge in non-OPEC production in the first half of the 1990's was biased toward light sweet crudes.

Crude Sources for the Largest Importers

Nine U.S. refining companies each imported more than 300 thousand barrels per day of crude last year, accounting for almost two-thirds of all U.S. crude imports. Leading the pack was Citgo, closely followed by Mobil and Texaco. Beyond size, the top nine's crude import slates had little in common (Figure 62).

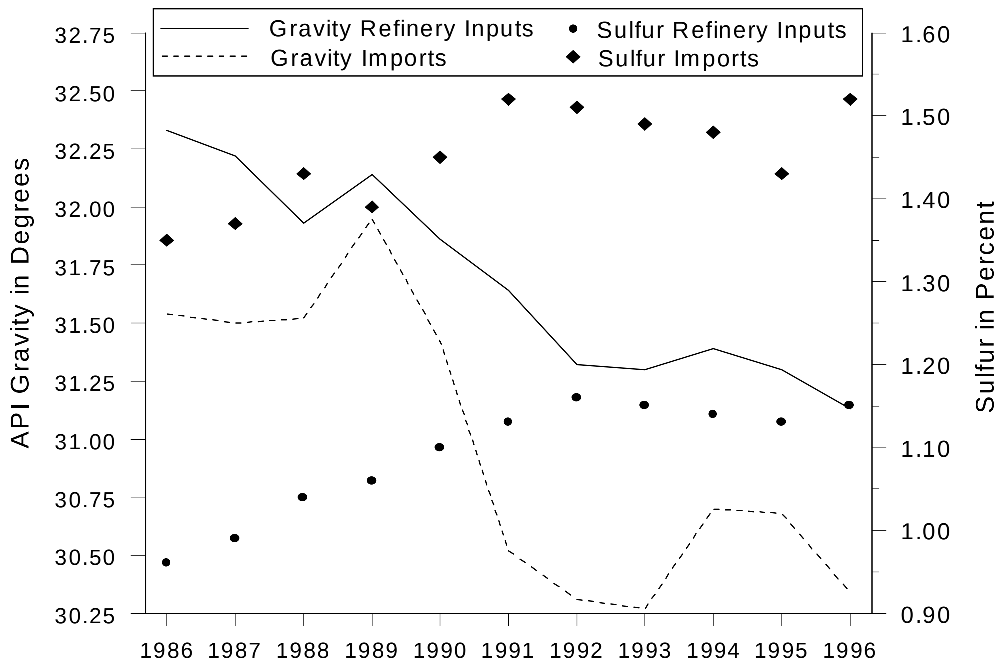
(Note: imports made by joint venture refining companies are combined with those of the U.S. based parent company most responsible for supply, i.e. Star with Texaco, Lyondell and Unoven with Citgo, the wholly-owned U.S. subsidiary of PDVSA, and Deer Park, a limited partnership of Pemex with Shell Oil, with Shell Oil.)

Many, frequently interdependent, factors contributed to this lack of homogeneity. The most obvious one is ownership/vertical integration through a joint venture relationship with a producer, because this resulted in importers that were especially single minded about their crude sources:

- *Citgo*: Last year, 85 percent of its crude imports were from Venezuela. Another 7 percent were from Mexico, indicating that Citgo was already capable of running an unusually heavy slate. This year, with Lyondell's new coker up and running, the proportion of heavy, Latin American crudes could move even higher.

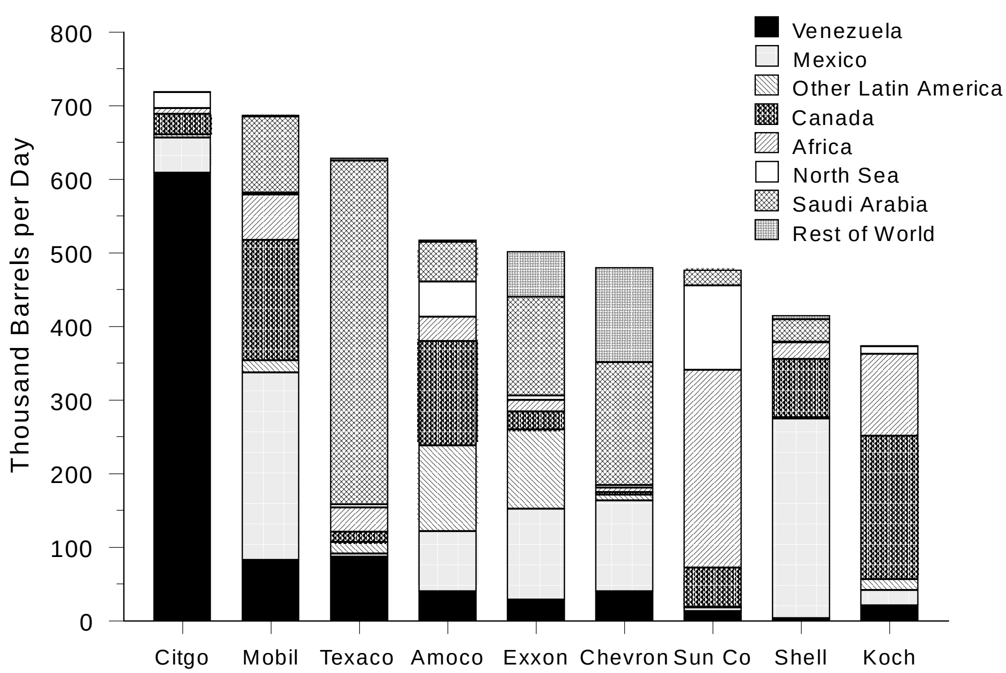
- *Texaco*: Its joint venture partner in Star is Saudi Arabia, which accounted for three quarters of Texaco's imports in 1996. Such a strong link with a long-haul supplier

Figure 61. Quality Trends in U.S. Crude Oil Imports and Refinery Inputs



Sources: **Import Data:** Energy Information Administration (EIA), derived from Form EIA-814. **Refinery Inputs:** EIA, *Petroleum Supply Annual* (1986-1995) and EIA, *Petroleum Supply Monthly* (March 1996-February 1997).

Figure 62. U.S. Crude Oil Imports by the Top Nine Importing Refiners and by Supply Region, 1996



Source: Energy Information Administration, Form EIA-814 data.

could be a competitive disadvantage in a U.S. market dominated by short-haul imports.

- *Shell Oil*: Its joint venture arrangement with Pemex at its Deer Park refinery included installation of a new coker. Last year, two thirds of its imports were from Mexico.

The others on the Top Nine list have more diverse crude import portfolios, but the factors driving many of the choices are still frequently easy to determine. These factors include:

- *Location* is why Koch Industries took half its crude from Canada. Its main refinery in Minnesota has gained significant competitive advantage from maximizing its use of Canadian Heavy, which has frequently traded in a buyer's market. Amoco and Mobil's propensity for Canadian crude has the same derivation.

- *Equity production* — either present or past — is why Amoco is the only significant importer of Trinidadian crude, and Chevron and Exxon are the largest importers from Saudi Arabia after Texaco/Star.

- *Refinery configuration constraints* mean Sun's slate is dominated by West African and North Sea crudes because its refineries are relatively simple by U.S. standards. Sun adopted a policy last year of minimizing capital investment, dropping out of the asphalt market, and restricting its crude slate to quality crudes.

Sun would probably have had the company of one other light sweet oriented importer on the Top Nine list if either British Petroleum had not sold its Marcus Hook, Pennsylvania, refinery to Tosco in February 1996, or Tosco had chosen to run it last year. But that would still place such importers in the distinct minority. If size is in any sense an indicator of success, then this analysis confirms a strong correlation between success and the ability to run significant proportions of poor quality, imported crudes.

The list of the largest crude importers has changed over time as mergers and acquisitions have reshaped the downstream sector. With a new wave of restructuring sweeping through the industry, further changes are inevitable. In particular, the top nine importers, whoever they are, will become even more dominant.

Seasonality of Imports

U.S. crude oil import requirements are seasonal (Figure 63), tied to, but not precisely in step with, the seasonality of U.S. oil consumption. Since imports are the marginal source of supply for the U.S. market, they can be thought of as an indicator of both refinery runs and consumption. Whether they lead or lag stock policy, and by how much, is a function of price, particularly the inter-month spreads, as well as other factors, such as refinery turnarounds, accidents, and supply disruptions (see Chapters 5 and 6).

In general, the volume of total and of the better quality, light sweet crude imports varies seasonally. U.S. consumption's summer peak is driven primarily by gasoline, as people take to the road during the traditional vacation season. This peak consumption coincides with the tightest seasonal quality specifications for gasoline, and presents a challenge to the U.S. refining sector, for which its upgrading capacity for the cheaper, poorer quality crudes is inadequate, even when fully utilized and with no turnarounds. Refiners turn for their marginal barrel to grades with a naturally high gasoline fraction, which means they turn to the light sweet crudes.

U.S. consumption is counter seasonal to global consumption, which is strongly winter peaking, with a 3-4 million barrel a day swing from quarterly peak to trough. These regional differences cause crude flows to swing west into the Atlantic Basin in the spring and summer, and east into the Pacific Basin in the winter. Such flows are accompanied by, if not initiated by, swings in relative crude prices. This causes the relative strength in U.S. domestic crude prices that typically occurs in the spring and early summer. With the U.S. particularly dependent at that time of year on light sweet crudes, that relative strength is most pronounced for grades such as the U.S. marker crude, West Texas Intermediate (WTI). In years when mid-continent crude stocks are low, or pipeline capacity is tight, the result can be price spikes and disconnects with world prices.

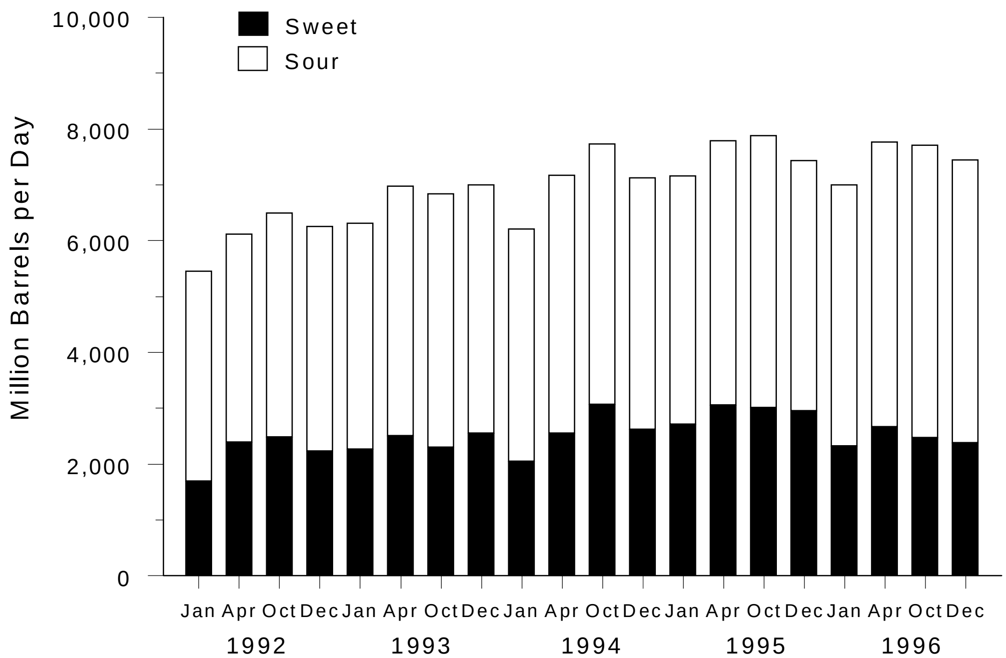
Crude Oil Exports

Crude oil exports play a minor role in the U.S. crude oil balance, averaging just 100-200 thousand barrels per day since 1985 (Figure 64), because they have essentially been banned for most grades most of the time. However, even if there were no restrictions at all, the status of the U.S. as the world's largest net importer of crude would ensure that exports would remain small in almost all circumstances.

Export Ban Diverted Alaskan Oil to East of the Rockies and the Virgin Islands

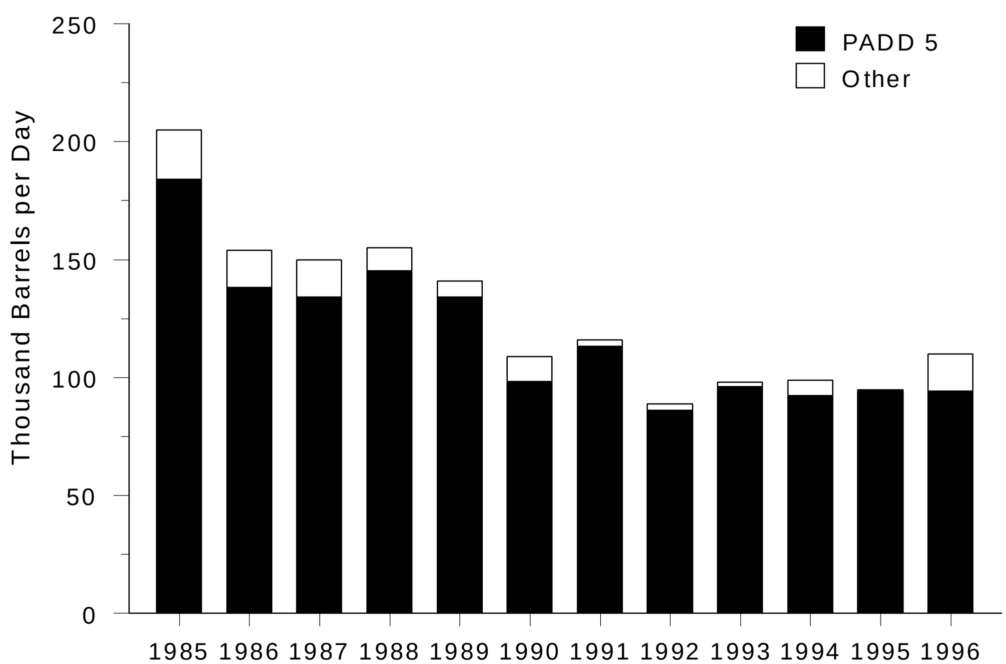
This would not entirely have been the case when Alaskan North Slope (ANS) production was in its prime. Its substantial West Coast surplus would have moved primarily to Asia if normal supply economics had applied. Instead, an ANS-specific export ban meant effectively that it could only

Figure 63. Quarterly Volumes of U.S. Crude Oil Imports by Sulfur Content



Source: Energy Information Administration, Form EIA-814 data.

Figure 64. U.S. Crude Oil Exports by Exporting Region, 1985-1996



Sources: Energy Information Administration (EIA), *Petroleum Supply Monthly* and EIA, *Petroleum Supply Annual* (various issues).

be moved either east of the Rockies or, under a special exemption for U.S. territories and possessions, to the Virgin Islands or Puerto Rico — with both the latter still counting as exports in the statistics. None of these destinations would have been natural choices in a free market because of the significant freight costs attached to such moves due to either Jones Act restrictions or sheer distance. For example, the voyage from Valdez, Alaska to the Virgin Islands is the longest regular voyage in the world oil market, covering around 15,000 (nautical) miles and taking up to 50 days. But all these markets, particularly the Virgin Islands, helped at times to increase the producers' total net revenue relative to the alternatives of either swamping the West Coast or limiting ANS production.

It was therefore ANS flows to the Virgin Islands that accounted for the overwhelming majority of U.S. crude oil exports over the last decade, which is also why almost all exports flowed out of the West Coast. And it was primarily the decline in both ANS and Californian production, together with the increased flexibility of West Coast refiners to run greater volumes of these poorer quality crudes, that led to the halving of exports in the second half of the 1980's.

With the Ban Lifted, Alaskan Crude Is Moving to Asia

After nearly twenty years of production, and with volumes only 70 percent of peak flows, a Bill lifting the ban on ANS exports was finally passed in November 1995 and implemented in July 1996. On the surface, nothing appears to have changed, with ANS exports in 1996 equal to those in 1995. But the absence of any increase is due to the continuing decline in ANS production, which was down another 90 thousand barrels per day in 1996. The new reality is being reflected in the flows. Waterborne, and almost all pipeline, flows of ANS to the Gulf Coast have ceased; exports to the Virgin Islands have plunged to 10 thousand barrels per day in the last five months from over 90 thousand barrels per day in the previous three and a half years; and significant parcels of ANS have moved to four Asian countries, although these movements have been intermittent except for the 50 thousand barrels per day to Korea.

The ongoing decline in the West Coast surplus of ANS crude was gradually eroding ANS in-transit stocks of this crude. Lifting the export ban has caused a further, sharp reduction since ANS in transit overseas to destinations other than the Virgin Islands is not included in this calculation. This contributed to the exceptionally low crude stock levels seen in the U.S. in 1996 (see Chapter 5).

Non-ANS Exports Are Minor

The non-ANS component of U.S. exports has included intermittent, minor flows from other special case sources on the West Coast, such as Cook Inlet production from Alaskan state waters and, since 1991, Californian heavy crude. There has also usually been some U.S. crude moving north by pipeline or truck into eastern Canada. The very modest baseload comes from production near the border, augmented, when the economics are favorable, by more widely traded crudes like West Texas Intermediate. (Note that crude oil in transit through the U.S. for Canada, such as via the Portland pipeline to Montreal, does not show up in these export statistics.)

U.S. Crude Exports Will Always Be Modest

As Asian refiners adjust to ANS crude, become more comfortable with U.S. tanker legislation, and more market oriented as their markets become more open, then crude oil exports from the U.S. could temporarily grow modestly again. But U.S. exports will never be a significant force in world crude markets.

5. Petroleum Stocks: Causes and Effects of Lower Inventories

Stocks are needed to keep petroleum supplies moving smoothly from wellhead to end user. As an immediate source of supply, stocks provide a cushion against normal and unexpected demand and supply fluctuations. Crude oil, distillate, and total gasoline stocks dropped in 1995 and reached new lows in 1996, drawing attention to the long-term downward trend. This led to questions as to whether the lower stocks caused greater price volatility, whether the stock cushion was adequate (particularly in light of more efficient industry operations), whether the reformulated gasoline program in 1995 influenced stock levels, and whether the decline in stocks is short lived or lasting. The following chapter reviews the trends in EIA's comprehensive survey data on petroleum stocks in conjunction with other information on prices and industry activity to provide the background required to begin answering these questions. This chapter also identifies and assesses the short and long term factors that influence stock levels.

Introduction

Total U.S. gasoline stocks have been shrinking since the early 1990s. Near the beginning of 1995, stocks of crude oil, distillate, and gasoline started to decline so precipitously that, by May of that year, stocks fell below the 1991-1995 average level and have yet to recover (Figure 65).[26] In March 1996 crude oil, distillate, and total gasoline inventories were 593 million barrels, the lowest recorded in more than 15 years. When stocks are low, demand surges or supply shortfalls cause buyers to turn to spot markets for immediate supplies while waiting for production and/or imports. During such times, buyers tend to bid up prices to assure supply in a tight market. This occurred in spring 1996 when low crude oil, distillate, and total gasoline inventories forced refiners and marketers to rely more heavily on spot markets to meet unexpected heating oil and seasonally rising gasoline demands. This event contributed to the rise in the price of crude oil.[27]

Table 6 shows the recent changes in petroleum stocks disaggregated by type (crude oil, distillate, and total gasoline), industry sector (mainly refineries, tank farms/bulk terminals, and pipelines), and Petroleum Administration for Defense District (PADD). Of the 64-million-barrel 1994 to 1996 decline in stocks, the greatest volumetric decrease occurred in crude oil (32 million barrels) while the greatest percentage decline occurred in distillate (15 percent). Much of the decline in crude oil, distillate, and total gasoline stocks occurred at bulk terminals/tank farms where more discretionary stocking takes place. The drop in stocks is most evident in PADD I (East Coast), where consumption is concentrated, and PADD III (Gulf Coast), a major refining area.

Prior to 1995, it was refinery closures, caused in part by the decontrol of the oil industry, that had the most important impact on petroleum stocks. Between 1981 and 1986, 108 refineries closed and inventories declined as the storage capacity associated with these facilities was decommissioned. Since the beginning of 1995, price risk, where the commodity stored is expected to be *less* valuable in the future because prices are overvalued in the present, appears to be one of the most important factors behind the reduction in stocks. Poor profitability, driven by low gross refining margins, also contributed to the drop in inventories.

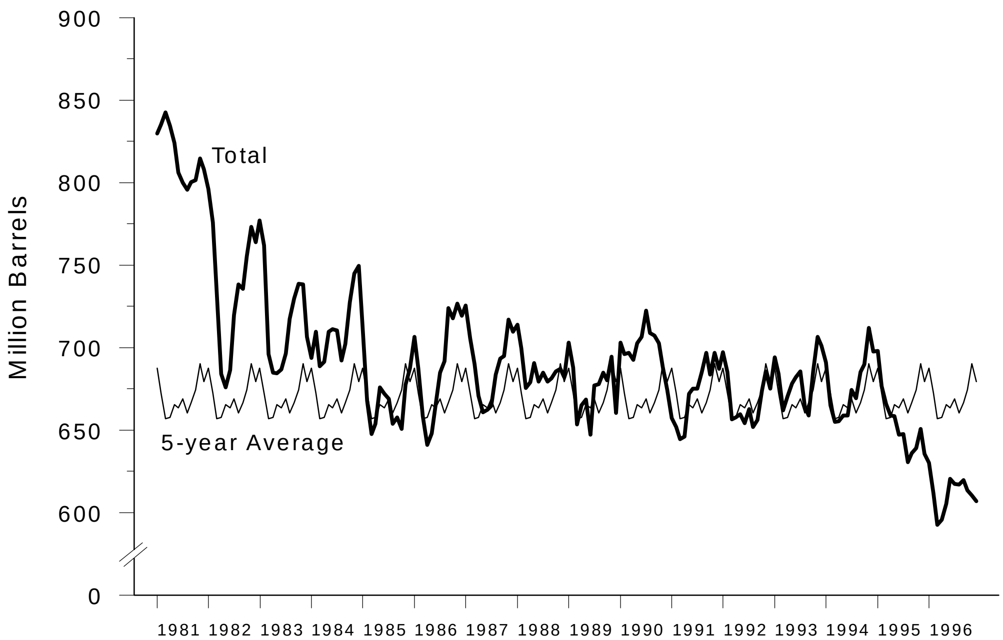
The forces that influence petroleum inventory levels can be divided into two categories. The first category consists of short term forces that influence refiners' (and to some extent, marketers') day-to-day decisions concerning inventory levels. These forces include current and expected prices, refining margins, the cost of storage, and the risk of stockouts, along with seasonal changes in product demand levels. The second category includes long term forces such as increased offshore stocks, enhanced inventory management through improved information technology, consolidation of petroleum storage facilities, the shift to short-haul crude oil sources, the introduction of clean products, and the change in secondary stocks.[28]

[26]Only crude oil, distillate, and total gasoline (finished gasoline plus blending components) stocks are addressed in this analysis. Excluded are stocks of all other petroleum products including jet fuel, residual fuel oil, and propane. Stocks held in the Federally owned Strategic Petroleum Reserve (SPR) are discussed separately (see box, p. 87).

[27]U.S. Department of Energy, *An Analysis of Gasoline Markets Spring 1996*, DOE/PO-0046 (Washington, DC, June 1996), p. 4.

[28]Primary stocks include crude oil or petroleum products held in storage at leases, refineries, natural gas processing plants, pipelines, tank farms, and bulk terminals that can store at least 50,000 barrels of petroleum products or that can receive petroleum products by tanker, barge, or pipeline. Secondary stocks include stocks at facilities having less than 50,000 barrels capacity or supplied strictly by tanker truck. Tertiary stocks are stocks held by end users.

Figure 65. Aggregate Crude Oil, Distillate, and Total Gasoline Stocks[1], January 1981-December 1996
(Million Barrels)



[1]Includes crude oil, distillate, and total gasoline (finished gasoline plus blending components) only.

Source: Energy Information Administration (EIA), Forms EIA-810 "Monthly Refinery Report," EIA-811 "Monthly Bulk Terminal Report," EIA-812 "Monthly Product Pipeline Report," and EIA-813 "Monthly Crude Oil Report."

Table 6. Crude Oil, Distillate, and Total Gasoline Inventories by Industry Sector and PADD, 1994-1996
(Million Barrels)

	1994	1995	*1996*	*Difference (1996-1994)*
Petroleum Type - Total	**676**	**654**	***612***	***-64***
Crude Oil	336	322	*304*	*-32*
Distillate	126	126	*107*	*-19*
Total Gasoline[1]	214	206	*201*	*-13*
Crude Oil, Distillate and Total Gasoline Stocks by Industry Sector[2]				
Refineries	208	206	*195*	*-13*
Bulk Terminals	155	149	*131*	*-24*
Pipelines	77	78	*77*	*0*
Crude Oil Tank Farms and Pipelines	198	184	*177*	*-21*
Crude Oil Leases	18	17	*17*	*-1*
Alaska Crude Oil in Transit	20	21	*15*	*-5*
Crude Oil, Distillate and Total Gasoline Stocks by PADD				
East Coast (I)	128	124	*106*	*-22*
Midwest (II)	159	154	*145*	*-14*
Gulf Coast (III)	253	239	*231*	*-22*
Mountain (IV)	21	21	*20*	*-1*
Pacific (V)	115	115	*110*	*-5*

[1]Finished gasoline plus blending components.

[2]In other published EIA data, bulk terminals that make finished gasoline by mixing blend stocks and/or oxygenates are included in the "Refinery" category. In the following entries, EIA data for distillate and gasoline were adjusted by removing the stocks these blenders report from the "Refinery" category and including the volumes in the "Bulk Terminals" category.

Source: Energy Information Administration (EIA), Forms EIA-810 "Monthly Refinery Report," EIA-811 "Monthly Bulk Terminal Report," EIA-812 "Monthly Product Pipeline Report," and EIA-813 "Monthly Crude Oil Report."

The Status of the U.S. Strategic Petroleum Reserve

The Strategic Petroleum Reserve (SPR) was created pursuant to the Energy Policy and Conservation Act of 1975 to mitigate the impact of disruptions in petroleum supplies and to carry out obligations of the United States under the Agreement on an International Energy Program. The reserves can be drawn down when the President determines that an energy supply emergency exists or could exist, and is of significant enough nature to adversely affect the economy.

The SPR facilities are designed to hold 680 million barrels of petroleum in three storage complexes in Texas and Louisiana. The SPR crude can be delivered to refineries in the Gulf Coast and Midwest through various connections to the U.S. petroleum pipeline network. The SPR crude can also be delivered by tanker or barge.

Persian Gulf War

On January 16, 1991, in conjunction with the beginning of Operation Desert Storm, President Bush ordered a drawdown and distribution of SPR petroleum as part of a coordinated plan agreed to by member countries of the International Energy Agency.[28] The Department of Energy issued a Notice of Sale for 33.75 million barrels.

In total, 17.2 million barrels of oil was sold from the SPR to a total of 13 purchasers between January 17 and March 31, 1991. This event marked the first emergency drawdown and sale of SPR oil. Even though the volumes sold were small, the use of the SPR at the onset of Operation Desert Storm provided an instantaneous counter force to expected market panic.[29]

Current Sales and Stock Levels

In 1996, under Congressional direction, the U.S. Department of Energy sold 5.1 million barrels of petroleum from Weeks Island to 4 buyers between February 26 and March 21. The proceeds from the sale, totaling $97 million, were used to relocate oil from the geologically unstable Weeks Island facility.

Again in May, pursuant to the Fiscal Year 1996 budget bill, the U.S. Department of Energy undertook an expedited release of up to 15 million barrels to raise an additional $227 million. The expedited nature of the sale was in response to the increase in petroleum prices in Spring 1996. Between April 29 and mid-May, the announcement of this sale along with other factors lowered petroleum prices by $1.60 per barrel.[30] The last contract under this sales effort was awarded in August. In total, the government sold 12.8 million barrels of petroleum from SPR at an average price of $17.77 per barrel to 9 companies.

The Fiscal Year 1997 appropriations act directed the sale of SPR oil to raise $220 million to fund the Reserve's facility requirements for that year. Sales pursuant to this act began in October and ended December 1996 with 10.2 million barrels sold for $220.6 million.

Following these sales, the Reserve had an inventory of approximately 563 million barrels of oil, enough to cover 66 days of net U.S. oil imports. Commercial petroleum and product stocks add another 109 days. The total, 175 days, is well in excess of the 90 minimum required in the Agreement on an International Energy Program. The U.S. ability to cover its agreement is negatively affected by the expected growth in imports and the decline in commercial stocks, as well as sales from the SPR.

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[28]U.S. Department of Energy/Office of Fossil Energy, *Strategic Petroleum Reserve Quarterly Report,* DOE/FE-0220P-1 (Washington, DC, May 15, 1991), p. 7.

[29]*Petroleum Intelligence Weekly,* "President Clinton and How Not to Use the SPR," Vol. 35 #19 (May 6, 1996), p. 7.

[30]U.S. Department of Energy, *An Analysis of Gasoline Markets Spring 1996,* DOE/PO-0046 (Washington, DC, June 1996), p. 7.

Background

Inventories are necessary to ensure the uninterrupted operation of each step of the petroleum supply system from wells and seaports through refineries to wholesalers and retailers and, ultimately, the consumer. Refiners use inventories as a means to improve production scheduling, and suppliers use inventories to buffer against expected and unexpected supply or demand variations. Inventories can also serve as a hedge against price fluctuations. The focus of this analysis is on primary stocks, the target of EIA data collection efforts. Stocks in secondary and tertiary (end user) storage facilities are excluded from this analysis.

EIA collects data on crude oil stocks for four segments of the industry: refining, tank farms and pipelines, production lease sites, and Alaskan supplies in transit. Crude oil is first stored in tanks that accumulate oil from producing wells. The volumes held on the leased property awaiting transportation are included in EIA's "leases" category. Small pipelines or tank trucks collect the crude oil and deliver it to intermediate storage for pooling before transport via major pipelines. Large diameter pipelines carry the crude oil to hubs, focal points for a number of pipelines, where the crude oil is collected for batching and redistribution to other pipelines. The volume of crude oil progressing through the pipeline system is included in EIA's "pipeline fill" category.

Tankers deliver crude oil imports to marine terminals and refineries. The volumes associated with this activity are included in EIA's "tank farm" and "refinery" categories, along with domestic volumes. Storage is required at this juncture because tankers are off-loaded at a rate that differs from the rate of crude oil input to refineries.[31] Also included in EIA's inventory statistics is Alaskan crude oil being shipped to the lower 48 states, Hawaii, and the U.S. Virgin Islands, referred to as "Alaska in Transit." Segregation of crude oil by quality necessitates substantial storage capacity throughout the supply system.[32]

EIA collects data on distillate and gasoline stocks from three segments of the industry: refining, bulk terminals, and pipelines. Domestic supplies of distillate and gasoline are produced mainly in the Mid-Atlantic, upper Midwest, California and the Gulf Coast, with the Gulf Coast producers acting as the supplemental suppliers to the Northeast and Midwest. In 1996, Gulf Coast production accounted for around 60 percent of the distillate and gasoline consumed in PADD I and around 15 percent of the distillate and gasoline consumed in PADD II. Depending on price incentives, imports can also supplement these supplies.

Taken together, crude oil, gasoline, and distillate inventories are usually at an annual peak in November as the heating season gets underway. As indicated in Figure 66, distillate stocks show more seasonality than crude oil and gasoline. Much of the variation in distillate demand results from the demand for heating oil, which accounted for a little over one third of total distillate fuel oil demand in 1996. In particular, PADDs I and II increase their demand for heating oil considerably during the winter because central heating systems that use heating oil are concentrated in those regions. PADD I swings from about 30 percent of total U.S. distillate demand in the summer to as much as 50 percent of U.S. demand in the coldest months (usually January through March). Stocks are especially important to winter distillate supply. During the winter months, stocks represent 12 percent of demand. The remainder of distillate consumption is in the form of diesel fuel for transportation applications, which has a flatter usage pattern over the course of the year, but cycles that run counter to the heating oil consumption pattern. In total, distillate stocks usually peak in November in preparation for high winter demand.

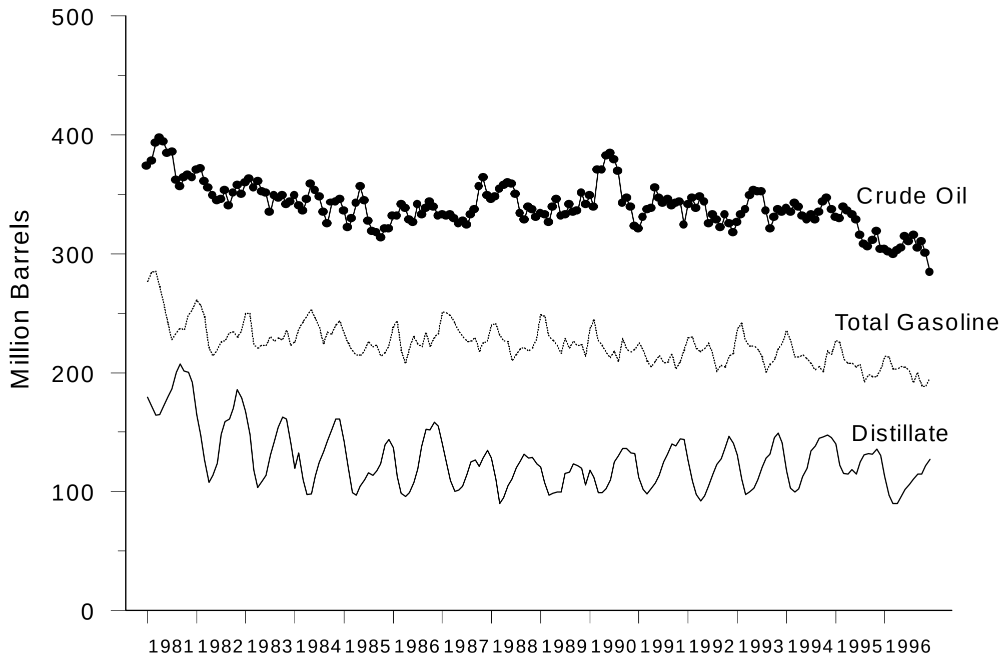
By contrast, all gasoline is consumed in the transportation sector. This fact introduces a different set of seasonalities. Gasoline consumption peaks during the summer vacation period and drops off in the winter as weather conditions inhibit travel. Therefore, gasoline stocks are high in January and February, when demand is low and supplies are produced as a by-product of distillate production. Gasoline stocks are normally depleted at the primary level in August, near the end of the driving season.

Crude oil does not show as much seasonality as distillate and gasoline. Whatever seasonality is present is driven by combined gasoline and distillate demand. According to data for the 1991-1995 period, crude oil stocks peak in May to assure that enough feedstock is on hand during the busy

[31]"Very Large Crude Carriers" (VLCC's) and "Ultra Large Cargo Carriers" (ULCC's) carry up to 4 million barrels of crude oil and can be offloaded at rates that exceed 500 thousand barrels per day. The average refinery processes about 100 thousand barrels per day. Storage is required due to the differences in these rates.

[32]National Petroleum Council, *Petroleum Storage and Transportation,* Volume IV (Washington, DC, April 1989), p. 21-28.

Figure 66. Crude Oil, Distillate, and Total Gasoline Stocks, January 1981-December 1996
(Million Barrels)



Source: Energy Information Administration (EIA), Forms EIA-810 "Monthly Refinery Report," EIA-811 "Monthly Bulk Terminal Report," EIA-812 "Monthly Product Pipeline Report," and EIA-813 "Monthly Crude Oil Report."

gasoline season. By December, crude oil stocks are depleted for physical and operational reasons.

Crude Oil

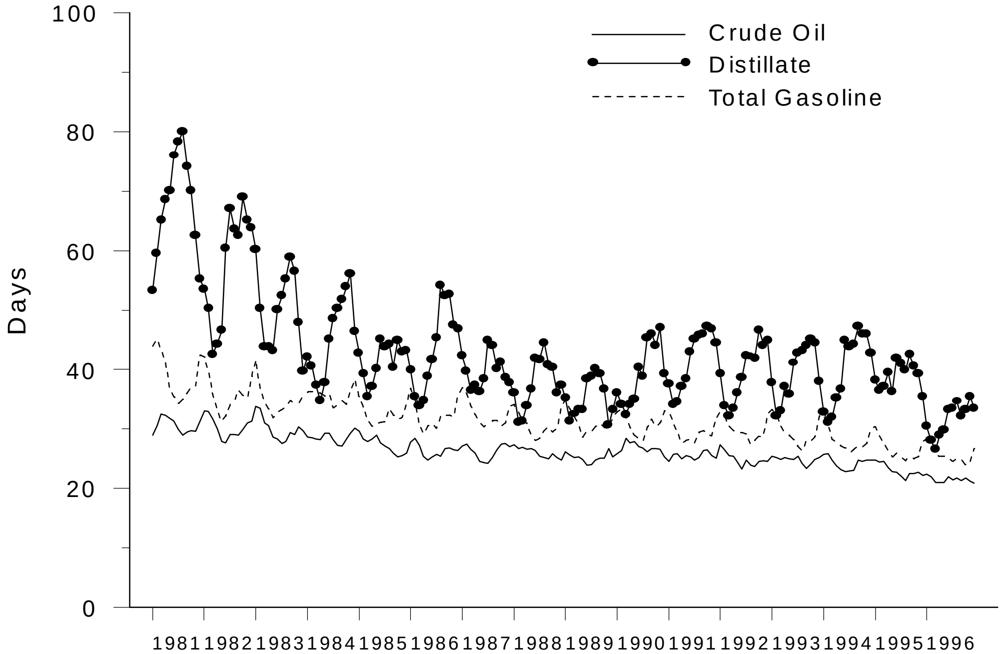
A closer look at crude oil stocks reveals a generally declining trend in the early 1980's (Figure 66). This decline coincided with the permanent closure of 108 refineries between 1981 and 1986. In the ensuing nine years, crude oil stocks remained fairly constant with two notable exceptions. Crude oil stocks rose in July 1987 and stayed high for a year because of the bargain prices brought on by OPEC overproduction and discount pricing. A contributing factor may have been the rising political tensions in the Persian Gulf that portended a possible supply disruption and higher prices.

In March 1990, U.S. crude oil inventories jumped 31 million barrels to a level 13.6 percent higher than the previous year, due to the expectation of rising crude oil prices. Stocks stayed at or above the average 1991-1995 level after the August 2, 1990 Iraqi invasion of Kuwait until late fall 1990, when it became apparent that other countries could make up the crude oil that would no longer be supplied by Kuwait and Iraq. During 1995 and 1996, crude oil stocks dropped precipitously mainly due to high winter 1995-96 demand and relatively high crude oil prices combined with an expectation for price decreases in the future and low refining margins. The following sections describe where the declines in inventory occurred.

Looking beyond seasonal ups and downs, days supply[33] of crude oil reveals a different pattern of near constant decline (Figure 67). Although crude oil input to refineries has increased by an average of almost 1 percent per year since 1981, days supply of crude oil in inventory has gradually decreased because stocks have failed to keep pace with the growth of inputs to refineries. In 1996, there were an average 22 days supply of crude oil resident at various segments of the industry compared to 24 at the end of 1994.

[33]Days supply of crude oil is defined as end-of-month inventory divided by the following month's crude oil input to refineries. Not all of this volume is available as input to refineries.

Figure 67. Days Supply of Crude Oil, Distillate, and Total Gasoline
(Days)



Source: Energy Information Administration (EIA), Forms EIA-810 “Monthly Refinery Report,” EIA-811 “Monthly Bulk Terminal Report,” EIA-812 “Monthly Product Pipeline Report,” and EIA-813 “Monthly Crude Oil Report.”

Crude Oil Stocks Declined at Tank Farms

Stocks in EIA’s tank farms and pipelines category represent almost 60 percent of all crude oil held in inventory (Table 7). These stocks declined 14 million barrels during 1995 and a further 7 million barrels in 1996. A considerable portion of the reduction was recorded in PADDs III and V, where crude oil is produced domestically. The decline in this category is more appropriately associated with tank farms. Stocks at pipelines represent pipeline fill and, therefore, are operational (rather than discretionary) in nature. As such, pipeline fill stays fairly stable from year to year.

Almost a third of all crude oil stocks are maintained at refineries. These stocks were essentially unchanged during 1995, but then decreased 5 million barrels in 1996. The decline was spread fairly evenly across the PADD regions. This reduction translated into lower days supply of crude oil in inventory. Several big refiners pared back to 4 to 5 days of supply on hand.[34] The average for all refiners was 6 days at the end of 1996, down from 7 at the end of 1994. With the lower stocks, refiners risked cuts in refining runs when supply disruptions occur. In January 1996, a reduction in refinery runs was forced on a number of Gulf Coast refiners when imports from Mexico and the North Sea were briefly disrupted at the end of the previous year.[35]

The crude oil stored on leases awaiting transportation is recorded in EIA’s “Leases” category. The drop in domestic production has resulted in less inventory being held at production leases. These stocks decreased from 18 million barrels in 1994 to 17 million barrels in 1995, and remained at 17 million barrels in 1996.

A drop-off in crude oil deliveries from Alaska to refiners in Hawaii, California, the Gulf Coast, and the U.S. Virgin Islands was evident in 1996, when a decline from 1994 of roughly 5 million barrels in stocks was recorded (Table 7).[36] Apart from the normal variation in this series, deliveries of Alaskan crude oil to the Far East started in July 1996 at a rate that averaged 73 thousand barrels per day through the end of the year, providing the basis for some of this decline.

[34]*Petroleum Intelligence Weekly,* “Refiners Test Limits of Lean Inventory Strategy,” Vol. 35 #03, (January 15, 1996), p. 1.

[35]*Petroleum Intelligence Weekly,* “Refiners Test Limits of Lean Inventory Strategy,” p. 1.

[36]A company was added to the survey frame in 1994 resulting in a higher estimate for Alaskan crude in transit compared to 1993.

Table 7. Average Crude Oil Inventories by Industry Sector
(Million Barrels)

Sector	1994	1995	*1996*	*Difference (1996-1994)*
Refiners	100	100	*95*	*-5*
Tank Farms and Pipelines	198	184	*177*	*-21*
Leases	18	17	*17*	*-1*
Alaska in Transit	20	21	*15*	*-5*
Total	**336**	**322**	***304***	***-32***

Note: Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration (EIA), Forms EIA-810 "Monthly Refinery Report,"and EIA-813 "Monthly Crude Oil Report."

Crude Oil Stocks Declined in Gulf Coast Area

Of the 32 million barrel decline in crude oil inventories from 1994 to 1996, 19 million barrels occurred in PADD III, the Gulf Coast area (Figure 68) where crude oil production and refining are concentrated. Some of the 7 million barrel drop in PADD II (Midwest) stocks may be related to a reduction in stocks in Cushing, Oklahoma, the spot market for sales of West Texas Intermediate crude oil.

Days supply of crude oil varies from PADD to PADD. The regional difference can be traced as far back as 1981. In 1996, PADD I, the East Coast, had 11 days of crude oil supply, while PADD V (West Coast) had 28 days supply. The average for all PADDs was 21 days. One explanation for this difference is the lack of oil production (and the associated stocks at leases, tank farms and pipelines) in any significant volumes in PADD I. Furthermore, PADD I receives all of its supplies by tanker or barge that, unlike pipeline supplies, are unaccounted for in EIA's data collection efforts while in transit.[37] Over 90 percent of the crude oil inventories in PADD I are stored directly at refineries, compared to less than a third in other PADDs.

Distillate

During the early- to mid-1980's, distillate stocks were on a generally declining path (Figure 66) due largely to petroleum industry downsizing. In the late 1980's, three consecutive winters with unusually cold weather[38] produced unexpected demand for distillate that was supplied largely through inventory withdrawals and resulted in historically low inventory levels. The following two winters were warmer than normal, causing a decline in demand and, thus, requiring less from inventory. By 1993, prices for distillate were expected to rise with the introduction of low sulfur diesel in October 1993. The increase in price induced a stock build at a time when environmental regulations imposed by the Clean Air Act Amendments of 1990 reduced the fungibility of diesel fuel and heating oil inventories. While the loss in fungibility may have increased stocks for a while after the introduction of the low sulfur diesel fuel, other market forces have acted to lower distillate stocks from levels seen before the introduction of the new product.

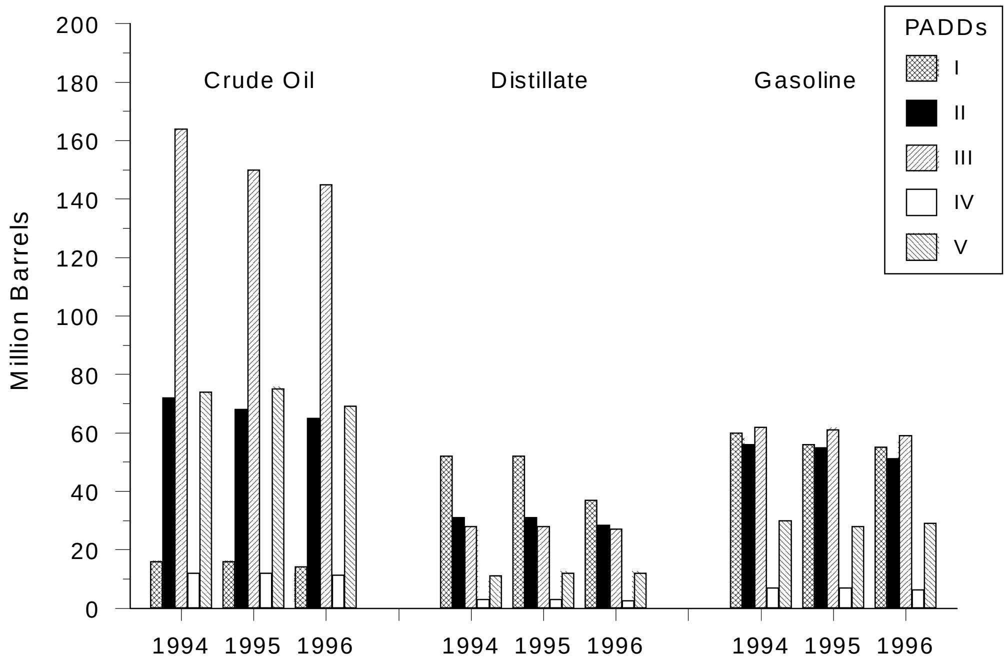
The decline in inventories that started in 1995 accelerated in 1996 when cold weather in January and February forced refiners to place a huge call on distillate inventories, leaving those inventories well below the 1991-1995 average. A late cold spell in April 1996 drove distillate demand to relatively high levels at a time when gasoline production should have been rising and distillate production declining. Strong diesel demand in the summer of 1996, attributable in part to robust economic growth, slowed the normal seasonal rebuilding of distillate stocks. Distillate production and imports were strong but not strong enough to rebuild stocks to the 1991-1995 average levels. The lack of normal storage replenishment in July, historically the biggest build month of the year, began to raise concerns. Through the end of the year replenishments were smaller than normal as prices for distillate in the future were expected to be less than current prices. Average distillate stock levels for 1996 finished 19 million barrels below the 1994 level.

In terms of days supply, inventories of distillate have decreased slowly since 1981, due to an ever increasing demand for this product (Figure 67). This decline accelerated in 1996. As Figure 67 illustrates, the days supply for distillate is higher than for either crude oil and gasoline, primarily due to the more seasonal nature of distillate consumption. Also, a large share of distillate consumption takes place away from the Gulf Coast refining center,

[37] The one exception is supplies from Alaska, referred to as "Alaska In Transit", which are included as such in totals for PADD V.

[38] The winters of 1987-1988 and 1988-1989 were colder than normal, and a severe cold shock occurred during December of the winter of 1989-1990.

Figure 68. Crude Oil, Distillate, and Total Gasoline Stocks by PADD Region, 1994-1996
(Million Barrels)



Source: Energy Information Administration (EIA), Forms EIA-810 "Monthly Refinery Report," EIA-811 "Monthly Bulk Terminal Report," EIA-812 "Monthly Product Pipeline Report," and EIA-813 "Monthly Crude Oil Report."

necessitating proportionately more stocks in reserve. In 1996, the industry had an average of 33 days supply of distillate on hand at various segments of the industry.

Distillate Stocks Declined at Bulk Terminals

Looking at the distillate primary inventory series[39], several things are clear (Table 8). Pipeline and refinery inventory levels changed very little compared to bulk terminal inventories. Due to the physical and operational requirements, pipeline fill rarely shows a significant change. Much of the stocking done at refineries is operational in nature, as well, with tanks collecting distillate production to create batches for shipping. As such, refineries have very little discretionary storage capacity in comparison to bulk terminals which are sized to accommodate large seasonal swings in supply and demand. Furthermore, bulk terminal operations seem to be the target of cost-cutting efforts because of the direct variable costs associated with storage in this segment of the logistics system. Unlike storage space at refineries or in pipelines, which is viewed as a sunk cost and does not represent either a direct expense or opportunity cost to refiners (apart from the interest costs of carrying working capital), storage at bulk terminals has a variable cost of about 1 cent per gallon per month.[40]

Although not indicated in Table 8, U.S. distillate inventories were low in 1989, much of which can be attributed to a reduction in bulk terminal holdings. After that, bulk terminal inventories increased, perhaps in response to the shortages that occurred at the end of 1989. The overall distillate inventory decrease in 1996 occurred primarily at bulk terminals.

[39]EIA collects primary inventory data from three groups of petroleum product inventory holders: refiners, pipelines, and bulk terminals. Included in the "Refinery" category are bulk terminals that make finished gasoline by mixing blend stocks and/or oxygenates. These facilities are required by EIA to report their inventories as "Refinery" inventories using the EIA-810 Form, "Monthly Refinery Report." Although blending operations do not affect the middle distillates, EIA data are adjusted in the following section so that the distillate stocks these blenders report are included in the "Bulk Terminal" category. The purpose of this is to more accurately reflect operations.

[40]EIA calculation based on discussions with energy industry sources. These costs are not completely variable in that each gallon not stored leads to a penny saved; some contract terms require a lease of multiple weeks or months regardless of whether the tankage is used. Furthermore, in order for the facility to remain economically viable, sometimes fixed tankage costs have to be prorated to a smaller stored volume.

Table 8. Average Distillate Inventories by Industry Sector
(Million Barrels)

Sector[1]	1994	1995	*1996*	*Difference (1996-1994)*
Refinery	34	32	*31*	*-3*
Bulk Terminal	67	68	*51*	*-17*
Pipeline	25	26	*25*	*1*
Total	**126**	**126**	***107***	***-19***

[1]In other published EIA data, bulk terminals that make finished gasoline by mixing blend stocks and/or oxygenates are included in the "Refinery" category. In the following entries, EIA data were adjusted by removing the gasoline stocks these blenders report from the "Refinery" category and including the volumes in the "Bulk Terminals" category.

Note: Totals may not equal sum of components due to independent rounding.

Source: Energy Information Administration (EIA), Forms EIA-810 "Monthly Refinery Report," EIA-811 "Monthly Bulk Terminal Report," and EIA-812 "Monthly Product Pipeline Report."

Distillate Stocks Declined on the East Coast

Distillate inventories at bulk terminals did not decline uniformly throughout the U.S. Much of the change occurred in PADD I, the East Coast, where there is a concentration in bulk terminals (Figure 68). The seasonal swings in total U.S. distillate inventories are mainly due to the seasonal swings in PADD I. The annual U.S. inventory average had shown an increase from 123.2 million barrels in 1989 to 136.3 million barrels in 1990. The year-to-year change in PADD I, where these inventories increased by about 15 million barrels, alone accounted for more than the U.S. total build.

In 1994, distillate stocks in PADD I (and the nation as a whole) were high, and a modest draw down occurred over the winter of 1994-95. With little need to build stocks, refiners drew off the excess and entered the winter of 1995-96 slightly below average. A combination of extended cold weather in winter 1995-96, high diesel demand, high crude oil prices, and expectations that prices would be falling depleted stocks and discouraged rebuilding. The annual averages for U.S. distillate stocks declined from 126 million barrels in 1994 to 107 million barrels in 1996. Eighty percent of the change was recorded in PADD I.

Days supply of distillate for the PADDs I, II, and III, which are integrated by the pipeline system that connects the refineries in PADD III with the consumption areas in PADDs I, II, and III, averaged 33 days in 1996. In 1994, the eastern half of the country averaged 42 days supply and 41 days in 1995. The western half of the country had 27 days supply in 1996 compared to 29 days in 1994. This calculation is influenced by the close proximity of refining and consumption in California.

Motor Gasoline

Like crude oil and distillate, gasoline stocks were on a generally declining path in the early 1980's (Figure 66) because of petroleum industry downsizing. This downward trend continued in the 1990's, with significant declines observed during the early 1990's and again in 1995 and 1996. Almost one-half of the decline between 1990 and 1996 in total domestic gasoline stocks occurred in 1990 and 1991 when crude oil and petroleum product prices rose and gasoline demand fell. Between July 1990, just before Iraq invaded Kuwait, and September 1990, the world price of crude oil climbed from about $16 per barrel to $36 per barrel.[41] The wholesale price of gasoline rose from 70 cents per gallon to almost $1 per gallon over this same period. The high product prices in the second half of 1990 and the economic recession that lasted through most of 1991 caused gasoline demand to decline from an average 7.3 million barrels per day in 1989 to an average 7.2 million barrels per day in 1992. Total gasoline inventories during 1991 averaged about 16 million barrels less than inventories during 1990.

Between 1992 and 1993, inventories of total gasoline slowly recovered. This occurred despite a large drawdown of finished gasoline inventory during the third quarter of 1992 to prepare for the first winter season for oxygenated gasoline. Tanks of conventional unleaded gasoline were emptied to make room for oxygenated gasoline. The third quarter stock draw was quickly reversed in the fourth quarter of 1992 because of the extra oxygenates required during the winter months.

[41]Energy Information Administration, *The U.S. Petroleum Industry Past as Prologue 1970-1992*, DOE/EIA-0572 (Washington, DC, September 1993), p. 57.

Although stocks were lower than normal in early 1995, following the startup of the reformulated gasoline program, inventories did not recover in late 1995 and early 1996 as they normally do following the end of the summer driving season. By that time, the industry was anticipating price declines in the crude oil feedstock as indicated by backwardation in the futures market (i.e., the price of crude oil several months in the future is less than in the current month).[42] This provided an incentive to hold-off making gasoline to stock. One cause for the anticipated lower crude oil prices was the possible sale of Iraqi crude oil. Gasoline stocks remained below average 1991-1995 levels throughout 1996.

Days supply of total gasoline has decreased (Figure 67) since 1981 because stock levels have failed to keep pace with a 1.1 percent per year growth in gasoline consumption. The decline in the days supply accelerated after 1995. In 1996, the United States had 26 days supply of total gasoline stocks, compared to 29 in 1994.

Inclusion of oxygenates increased the total days supply by 2 days at the end of 1996. Oxygenates — primarily methyl tertiary butyl ether (MTBE) and fuel ethanol — did not play a significant role in gasoline supply until late 1992, when the oxygenated gasoline program started. In January 1993, EIA stepped up efforts to collect data on oxygenates stocks to supplement the information on gasoline and gasoline blending components already collected. Inventories of oxygenates reported by EIA increased by about 8 million barrels between December 1992 and January 1993, primarily because of the extension of EIA oxygenate surveys to pipelines, bulk terminals, and oxygenate producers.[43] Nevertheless, even with the inclusion of oxygenates in the accounting of all gasoline stocks, these stocks still declined in 1995 and 1996.

[42]Energy Information Administration, “Summer 1996 Gasoline Assessment,” *Weekly Petroleum Status Report,* DOE/EIA-0209(96/14) (Washington, DC, April 10, 1996), p. xi.

[43]Before January 1993, only refineries were required to report stocks of oxygenates. Refinery oxygenate stocks were reported by EIA in various publications under the category “Other Hydrocarbons/Alcohols.” Beginning in January 1993, the sample frame for oxygenate inventories was expanded to include pipelines, bulk terminals, and oxygenate producers. The inventory of “Other Hydrocarbons/Hydrogen/Oxygenates” on January 31, 1993, was 14,016 thousand barrels. By comparison, the inventory of other hydrocarbons/alcohol at refineries on December 31, 1992, was 6,876 thousand barrels. Sources: Energy Information Administration, *Petroleum Supply Annual 1993, Volume 2,* DOE/EIA-0340(93)/2 (Washington DC, June 1994), pp. 26, 458 and *Petroleum Supply Annual 1992, Volume 1,* DOE/EIA-0340(92)/1 (Washington DC, May 1993), p. 69.

Gasoline Stocks Declined at Refineries and Bulk Terminals

In 1994, total gasoline stocks (finished gasoline plus gasoline blending components) averaged 214 million barrels. By 1996, the average dropped 6 percent to 201 million barrels. A comparison of annual average stock levels for the refining, pipeline, and bulk terminals segments of the industry indicates that a majority of the reduction in gasoline stocks has taken place at refineries and bulk terminals (Table 9).

Refinery inventories of total gasoline stocks represent about a third of total domestic gasoline stocks. Refineries also account for about 35 percent of total oxygenate inventories. Large drops in refinery inventories occurred in late 1995, causing the average for the year to decline from 74 million barrels in 1994 to 69 million barrels in 1996.

A reduction in gasoline stocks also occurred at the bulk terminal level, which accounts for about 40 percent of the total gasoline stocks. The reduction at bulk terminals represents an effort to lower direct variable costs associated with storage in this segment of the logistics system. In 1994, 88 million barrels of total gasoline stocks were stored in bulk terminals compared to 80 million barrels in 1996. As shown in Table 9, most of this reduction occurred in 1995.

Between 50 and 60 million barrels of gasoline are required to fill the domestic pipeline system so that refineries can supply remote bulk terminals on an ongoing basis. Pipeline fill shows little variance from month-to-month and year-to-year and represents about a quarter of total gasoline inventories. For the most part, gasoline inventories in pipelines consist of finished product since blending components stocks are held mainly at refineries.

Gasoline Stocks Declined in Eastern Half of Country

The overall downward trend in total gasoline stocks appeared predominantly in PADDs I, II, and III, which account for over 80 percent of bulk terminal gasoline supplies (Figure 68). Clearly, the decline in stocks at the bulk terminals impacted the totals recorded in these PADDs.

Days supply of total gasoline for the PADDs I, II, and III, averaged 32 days in 1996. In 1994, the eastern half of the country averaged 36 days supply and 34 days in 1995. The western half of the county had 26 days supply in 1996, unchanged from 1994.

Table 9. Average Gasoline Inventories by Industry Sector
(Million Barrels)

Sector[1]	1994	1995	*1996*	*Difference (1996-1994)*
Refinery	74	74	*69*	*-5*
Bulk Terminal	88	81	*80*	*-7*
Pipeline	52	52	*51*	*-1*
Total	**214**	**206**	***201***	***-13***

[1]In other published EIA data, bulk terminals that make finished gasoline by mixing blend stocks and/or oxygenates are included in the "Refinery" category. In the following entries, EIA data were adjusted by removing the gasoline stocks these blenders report from the "Refinery" category and including the volumes in the "Bulk Terminals" category.

Note: Totals may not equal sum of components due to independent rounding.

Source: Energy Information Administration (EIA), Forms EIA-810 "Monthly Refinery Report," EIA-811 "Monthly Bulk Terminal Report," and EIA-812 "Monthly Product Pipeline Report."

Short-Term Influences on Petroleum Inventories

The short-term influences of expected crude oil and product prices, refining margins, the cost of inventories, and the risk of stockouts affect refinery managers' day-to-day decisions about inventory levels. Some of these influence marketers' inventory decisions as well. The impact of the 1995-96 short-term events on stock levels is discussed below.

Expected Price Drop Discouraged Stock Building

Figure 69 shows the difference between prices for crude oil on the New York Mercantile Exchange for delivery three months into the future minus prices for crude oil for delivery one month into the future. Stock levels are also provided. Since prices for delivery one month in the future are similar to current prices, the difference highlighted in the figure is equivalent to the expected change in the price of crude oil. Figure 69 shows that, from the end of 1995 and through 1996, the decline in stocks followed the decline in the expected price of crude oil.

In 1995, the expected price for crude oil never exceeded the current price and the market was "backward." By December 1995, the petroleum supply/demand balance had grown tight as crude oil exports from Mexico were reduced by damage from Hurricane Roxanne. However, petroleum traders expected the supply situation to ease, causing prices to decline. With the expectation for significantly lower petroleum prices in the future, it appeared more cost effective to forego purchases until prices came down. This strategy minimized the price risk associated with purchasing a commodity that is overvalued in the present, only to have it become less valuable in the future. In February 1996, the U.N. opened discussion of Iraq's oil-for-food proposal. The ongoing talks and other market developments drove the market into further backwardation. Backwardation eased somewhat in the summer of 1996 when it became apparent that extra crude oil would not be supplied to the market, but persisted throughout 1996.[44]

Low Margins and Poor Profitability Forced Industry to Trim Costs

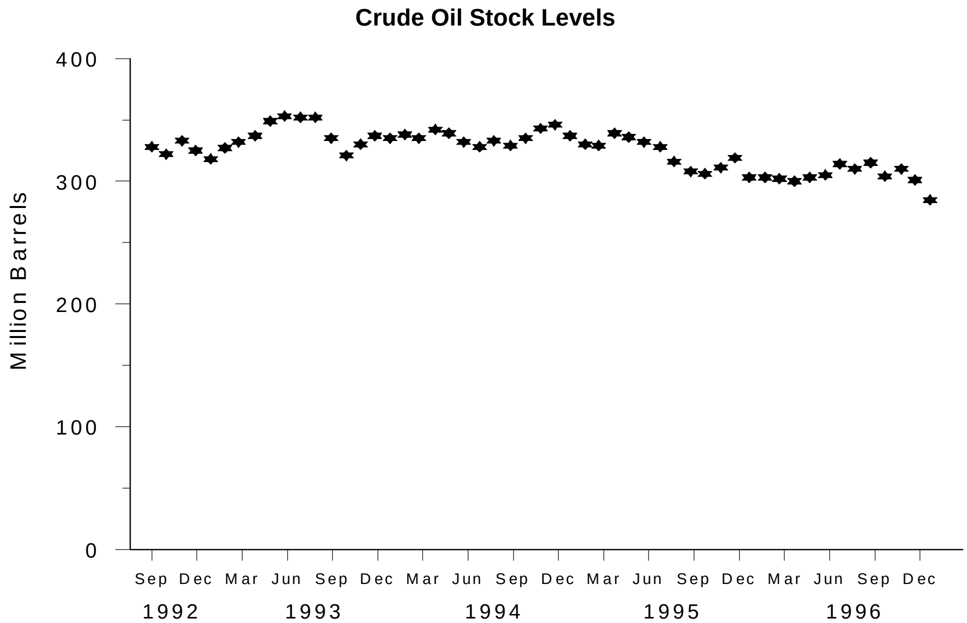
A barometer of the relative profitability of refining is the gross refining margin, i.e., the difference between the cost of the crude oil feedstocks and the price refiners receive for petroleum products produced. Gross refining margins are expected to cover not only refining costs but other costs as well, including logistics and marketing cost. While refiners may realize revenues from other activities, refining margins remain the most important source. Low margins forced refiners to trim costs in such areas as inventories.[45]

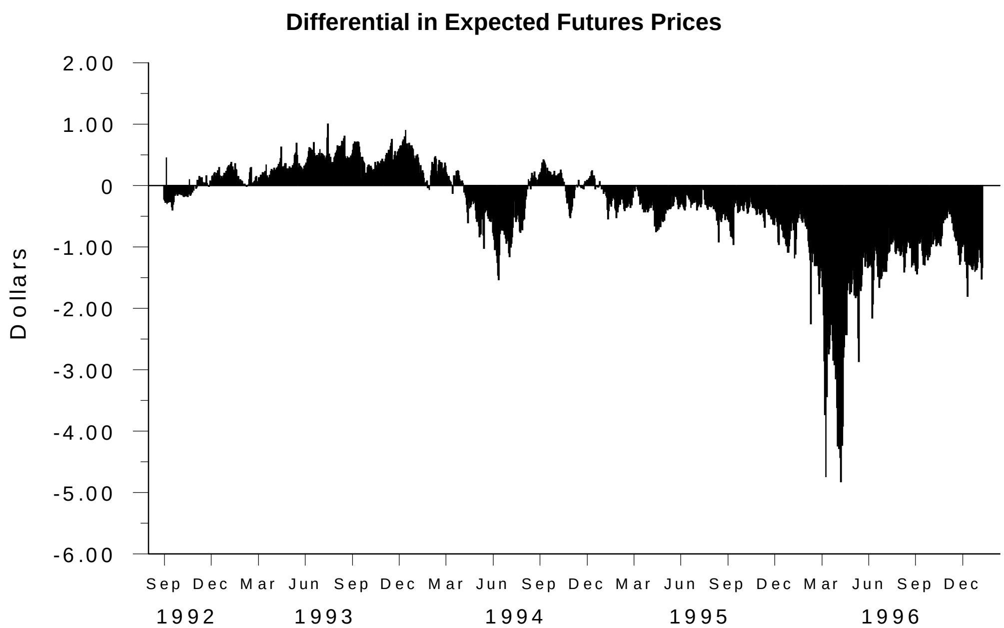
In 1994, gross refining margins edged downwards as increases in product prices failed to match increases in crude

[44]Chapter 6 provides a more detailed review of backwardation and the futures market.

[45]Inventory cost reduction is frequently referred to as a "just-in-time" inventory program. However, this does not correspond to the conventional use of the term in economic theory. Just-in-time inventory programs involve the sharing of both the benefits (i.e., lower inventory carrying costs) and the risks (e.g., running out of stocks) between suppliers and a manufacturer. Inventory reduction programs in the petroleum industry are generally not characterized by risk sharing but represent the recognition by individual firms that the benefits of carrying lower inventories are greater than the incremental risk assumed or that the risks of stocking out for a given inventory level are now lower.

Figure 69. Crude Oil Stock Levels and Differential in Expected Future Prices
(Dollars and Million Barrels)





Source: Energy Information Administration (EIA), Forms EIA-810 “Monthly Refinery Report,” EIA-813 “Monthly Crude Oil Report,” and Reuters News Service, various dates.

oil prices.[46] The 1995 refining margins were at their lowest since 1987 and the industry turned to trimming inventories. Results for 1996 suggest refining margins were improved over 1995.[47]

Cost of Maintaining Inventories Escalated In 1996

The cost of maintaining petroleum inventories is calculated by multiplying the current price of the material (crude oil, distillate, or gasoline) by the interest rate and adding the operating cost of tankage, about 30 cents per barrel for crude oil[48] and 42 cents per barrel for product.[49] The cost of inventories has increased since the beginning of 1994, mainly due to increases in prices for both crude oil and refined products. In spring 1996, these prices were driven up by marketers purchasing petroleum products to fill immediate needs. The price of crude oil (measured as the U.S. refiners average acquisition cost of imported and domestic crude) grew from $17.75 per barrel in January 1996 to $21.60 per barrel in April 1996. Over the same time period, distillate heating oil spot prices rose from 50.73 cents per gallon to 80.00 cents per gallon, and (reformulated) gasoline spot prices rose from 51.05 cents per gallon to 77.54 cents per gallon.[50]

Multiplying these prices by interest rates and adding tankage (operating) costs gave a figure of 42 cents per barrel per month for maintaining crude oil inventories in January 1995. The increase in the acquisition cost of crude oil pushed the inventory cost to as much as 45 cents per barrel in April 1996. The cost of distillate and gasoline inventories were 57 cents and 60 cents per barrel, respectively, in January 1995. By April 1996, these costs went to 61 cents per barrel for distillate and 62 cents per barrel for gasoline. This upward trend in costs, while small in comparison to the influence of expected lower prices in the future, could only effect petroleum inventory levels negatively.

[46]Energy Information Administration, *U.S. Energy Industry Financial Developments 1995 First Quarter*, DOE/EIA-0543(95/1Q) (Washington, DC, June 1995), p. 9.

[47]A thorough discussion of the 1996 refining margin is contained in Chapter 7.

[48]Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(96/03) (Washington, DC, March 1996), p. xix. Estimated cost of leasing commercial storage space.

[49]Estimated cost of leasing commercial storage space, according to discussions with industry sources.

[50]Reuters News Service, various dates.

Risk of Stockouts Was Reassessed

Refiners keep crude oil, distillate, and total gasoline stocks on hand to ensure a constant flow of product to consumers. The risks associated with supplies include embargoes and strikes as well as logistical problems in production, pipelines, and tanker/barge movements. Refiners and marketers informally assess risk of supply disruptions on an ongoing basis and prepare inventories accordingly. Demand surges, such as the one produced by the cold snap in January 1994, can also lead to stockouts if too little supply is in place.

The lower number of days supply on hand may suggest that petroleum supplies are believed to be more secure than previously thought and the risk of a disruption is lower. It may be that information systems and operational changes allow refiners to work with lower inventories without increasing risk of stockouts. The lower days supply may also be indicative of a belief that, thus far, decrements to inventories have not been large enough to increase the probability of product stockouts appreciably. Refiners' attitude toward risk is also a determinant of petroleum stock levels. Refiners may simply be willing to shoulder more risk than before, again leading to lower stocks. As previously documented, a policy of lower crude oil inventories has led to several reductions in runs at refineries.

Long-Term Influences on Petroleum Inventories

There are a variety of long-term influences affecting inventory levels, including increased offshore stocks, enhanced inventory management through improved information technology, consolidation of storage facilities, the shift to short-haul crude oil, the introduction of clean products, and the increase in secondary stocks. These trends are subtle and have almost no impact on the day-to-day inventory level decisions, but do affect inventory levels over time. Some of these forces represent reactions to the persistently poor financial performance in the refining industry.[51]

Offshore Stocks Also Declined

One explanation for some of the decline in petroleum stocks is the growth of stocks in facilities in the Caribbean. According to the *Weekly Petroleum Argus*, though, stocks at

[51]U.S. Department of Energy, *An Analysis of Gasoline Markets Spring 1996*, DOE/PO-0046 (Washington, DC, June 1996), p. 58-61.

independent storage terminals there went from 27.1 million barrels at the end of 1994 to 17.1 million barrels at the end of 1995 then 15.5 million barrels at the end of 1996.[52] Therefore, the activity in the Caribbean cannot substantiate the decline in U.S. crude oil, distillate, and total gasoline stocks. It appears that the same forces causing stocks to decline in the United States have affected Caribbean stocks as well.

Improved Information Systems May Have Facilitated Decline in Stocks

Improved information technology has given managers better tools needed to optimize stock levels. Computer programs and tracking systems for monitoring sales, production and inventories have become more sophisticated in recent years. While the availability of more accurate and more timely data may permit maintenance of lower inventories,[53] the impact of these technological improvements is difficult to quantify because of the presence of other trends in EIA data.

Closure of Storage Facilities May Have Reduced Stocks

Information on specific tank farm and bulk terminal sites is scarce. In an effort to reduce reporting burden, EIA collects stock information on a PADD basis, not by individual terminal. Without site-specific data to monitor trends, it is difficult to determine to what extent the decline in stocks is attributable to the closure of terminals.

Several industry publications have indicated that major oil companies are divesting their oil terminals and that independent terminal operators are buying some of these properties. However, it is unknown how much storage is being decommissioned by the new owners.[54]

Shift to Short-Haul Crude Oil Had Little Impact

With the decline in domestic production, crude oil imports have been increasing, particularly imports from the Western Hemisphere, referred to as "short-haul" crudes. In addition to shorter transit times, short-haul crude oil allows refiners to reduce inventories because of the smaller cargo sizes. Less storage is required because the smaller vessels used are offloaded at slower rates that more closely approximate refinery input rates. The ability for quick resupply also factors into a reduction in stocks.

In order to have a negative impact on inventory levels, imports from long-haul sources would have had to decline from one period to the next. Imports from outside the Western Hemisphere decreased only 190 thousand barrels per day in 1995 and another 124 thousand barrels per day in 1996. The reduction in stock requirements attributable to this shift to short haul sources is small, particularly in comparison to what stocks should have been given the growth in demand and a decline in domestic sources of crude oil.

Product Quality Regulations Had Little Long-Term Influence

Beginning in 1992, the introduction of various air quality regulations has had broad ranging impacts on the petroleum industry, including storage management.[55] These regulations covered Reid vapor pressure of gasoline (June 1989 and January 1992), the oxygenated gasoline program in carbon monoxide nonattainment areas (November 1, 1992), low sulfur diesel fuel (October 1, 1993), and reformulated gasoline (January 1, 1995).

Previously, distillate grades (heating oil and diesel fuel) could be stored together because of their similar specifications. Inventory planners could build total distillate inventories on the basis of demand expectations for heating oil and diesel fuel. Any unexpected demand for either product could be pulled from the other's inventories and production streams. With segregation, a cushion against unexpected demand had to be maintained for each product, which led to an increase in inventories.[56] The increase in distillate stocks after the start of the low sulfur diesel program in October 1993 (4 percent rise in 1994) may, in part, be attributable to the inefficiencies introduced by the legislation. It is more likely, though, that this increase was related to the expectation that distillate prices would rise, thus making inventories more valuable. Since then, average

[52] *Weekly Petroleum Argus*, various issues.

[53] *Fuel Technology and Management,* "Lower Gasoline Inventories Do Not Mean Higher Prices," (March/April 1996), p. 9.

[54] Energy Information Administration, *Storage and Transportation Changes Since 1989*, DOE/EIA-Draft Report (Washington, DC, June 1996), p. 5.

[55] A more thorough discussion of the impacts of environmental regulations is contained in Energy Information Administration, "Recent Trends in Motor Gasoline Stock Levels" and "Recent Distillate Fuel Oil Inventory Trends, What EIA Data Show," *Petroleum Marketing Monthly,* DOE/EIA-0380(96/06) (Washington, DC, June 1996), pp. xxi-xxiv.

[56] Energy Information Administration, *Petroleum Marketing Monthly,* "Distillate Fuel Oil Assessment for Winter 1995 - 1996," November 1995, Sidebar.

distillate stocks declined, meaning that other influences have outstripped the effects of environmental regulations. In some situations, suppliers have found it economical to substitute a clean fuel for a conventional fuel, rather than maintain additional stocks of the conventional fuel.

Fuel specification regulations have had an even smaller influence on gasoline stocks. EIA survey data for both refineries and bulk terminals indicate that the oxygenated and reformulated gasoline programs, required by the Clean Air Act Amendments of 1990, have changed the seasonality of stocking patterns from a third quarter build to a draw. The third quarter draw is necessary to draw down stocks for oxygenate blending in preparation for the start of the oxygenated season. Further research failed to identify any meaningful differences in stocking patterns between refineries that produce oxygenated and reformulated gasolines and refineries that produce only conventional gasolines, or between states that require the new clean gasoline and states that do not. The overall downward trend in inventories was apparently greater than any of the inefficiencies introduced by the Clean Air Act Amendments.

Refiners and bulk terminal operators made operational changes to meet the challenge of providing the additional gasoline types required by the Clean Air Act Amendments while still reducing stocks. For example, some oxygenate was moved from refineries to terminals, and in-line blending was added at bulk terminals, allowing operators to eliminate mid-grade storage in some cases. (Bulk terminal operators are able to make midgrade gasoline by blending premium and regular grades.) The willingness of companies to participate in exchange agreements and shared storage also may have allowed suppliers to accommodate new, clean products without increasing storage requirements.

Stocks Declined at Electric Utilities

An obvious cause of decline in distillate and gasoline stocks at the primary level may be an increase in stocks at the secondary and consumer levels. At the consumer level, EIA collects information on distillate stocks at electric utilities. Electric utilities accounted for less than 2 percent of distillate consumption in October 1996. The pattern of stocks since 1992, though, shows a definite decline in 1996, when consumption increased (Table 10). Higher prices served as a disincentive to replenishing stocks. Although utility stocks declined, this cannot be extended to other consuming sectors since utilities have some flexibility regarding the fuels they burn. Information on other secondary and tertiary stock levels is sketchy, at best.

Conclusion/Outlook

The 1995-96 decline in crude oil, distillate, and gasoline inventories occurred mostly at tank farms and bulk terminals, the point in the supply system most able to respond to changing supply economics. The declines in regional stocks, therefore, reflect the geographic distribution of these facilities, with the greatest reductions occurring in stocks of crude oil on the Gulf Coast and of products in the Northeast and Midwest.

The main determinant of inventory levels over this period was expected to be the increasingly stringent environmental regulations, requiring industry to stock a growing number of grades, thereby putting upward pressure on inventories. But this was overwhelmed by the downward pressure exerted by two other factors: the lower expected prices for crude, gasoline, and distillate; and the ongoing, poor financial performance of the downstream industry. Many other factors, such as the shift to shorter-haul crudes, offshore storage, and the cost of borrowing, had a much more minor impact on the industry's stock policy, but generally encouraged further reductions. The net result was new record lows for stocks of crude oil, distillate, and gasoline, which, in turn, contributed to higher price volatility.

Still, many questions concerning petroleum inventories remain unanswered. The most notable question is to what extent stock levels drive price volatility. The question of adequacy also persists, since the lower stock levels were untested during the mild 1996-97 winter. Lastly, the outlook for stocks brings into question the relative influences of expected prices and financial performance. Definitive answers to these questions must await quantitative analyses of the correlation between stock levels and prices, cost, and events such as the start of the clean fuels program. The downstream mergers recently announced (Texaco/Shell, Marathon/Ashland) give evidence that the industry expects low margins to continue, meaning that discretionary stocks will be minimized. From the standpoint of prices, changes in the supply situation are expected to stimulate stock building, since future prices are predicted to be equal to, or greater than, current prices.

With the flow of Iraqi crude oil and the end of the world’s peak petroleum consumption season (winter), expected prices are already more in line with current prices for February 1997 (after adjusting for seasonal trends). The futures prices on the New York Mercantile Exchange provides evidence of this trend.[57] EIA forecasts that as the crude oil supply situation eases and current and expected prices remain comparable, crude oil inventories are expected

[57] Reuters News Service, various dates.

Table 10. U.S. Electric Utility Distillate Consumption and Ending Stocks - October
(Million Barrels)

	1992	1993	1994	1995	1996
Stocks	15.4	14.8	15.6	15.6	14.5
Daily Consumption	0.792	0.897	0.811	0.932	1.477

Source: Energy Information Administration (EIA), Form EIA-759 “Monthly Power Plant Report.”

to go from 12 percent to within 3 percent of the 1991-1995 average levels by the end of the of 1998 while gasoline will go from 9 percent to within 4 percent of the historic average. A continuing tightness in world distillate markets, however, may cause distillate inventories to remain low (about 10 percent below the 1991-1995 average at the end of 1998).[58]

If the financial performance proves to be a more important factor than shown historically, then stocks may not recover to the extent forecast. Data for 1997 indicate the recovery in stocks may have already started; EIA’s projections are predicated on normal weather. If the intervening heating seasons prove to be unusually cold or if logistical problems occur, particularly with distillate, inventories could be tested and prices may go higher.

[58]Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(97/Q2) (Washington, DC, April 997), p. 29.

6. Petroleum Futures Markets: Volatile Prices, Controversial Functions, Stagnant Volumes

The development of futures markets in crude oil and petroleum products was one of the most important changes to oil and gas markets over the past two decades. As trading volume has grown, the ability of oil industry participants to hedge their price risk has improved since the increased volume has made it possible to take or liquidate a position without creating undue volatility in the futures price. But with the growth of futures trading, the same questions and concerns that pertain to futures markets for other commodities have arisen: Why and how do traders use the futures markets? Do large traders manipulate prices? This chapter examines these questions while focusing on an important trend: the end — at least for now — of the phenomenal growth in crude oil and petroleum product futures trading.

The Uses of Futures Markets

The Energy Information Administration is interested in futures markets because of the profound impacts that those markets have had on the marketing of crude oil and petroleum products. This chapter describes some fundamental investigations into the workings of the futures market that found that energy futures markets have performed as economic theory has predicted.

The theory of how futures markets are used and prices determined was originally derived for agricultural commodities. That theory should also apply to any storable commodity, such as crude oil and petroleum products. Grain markets and petroleum markets are subject to similar types of empirical testing because they both have large variations in stock levels every year due to periods of stockbuilding followed by gradual stock depletions. In spite of the fact that the stocking pattern in energy markets is more complex than in grain markets, using the same type of stocking and price correlation analysis as are used in grain markets shows that energy futures markets behave similarly to agricultural commodities, in a manner consistent with economic theory. To understand this behavior, it is first necessary to understand the reasons for the existence of futures markets.

To the casual observer, futures markets appear irrational and mysterious. However, the basic workings of futures markets are rational and easy to understand. Fundamental to understanding the futures markets is knowing how they are used in "hedging," to minimize the risk of price changes (see box, p. 102).

Economic theory[60] asserts that decisions to hedge depend upon several factors:

- **The futures contract should accurately reflect the product being hedged**. If the futures contract specifies delivery of a commodity that differs greatly from the commodity being hedged, the futures price movements may not eventually converge to the corresponding spot market price, making the futures contract much less useful as a hedging device.

- **There should be a close correlation between changes in the spot price and changes in the futures price**. Even if a futures contract gives a very close specification of the product being hedged, if the futures and spot prices do not change at approximately the same rate, the futures contract will not be an effective hedging instrument. For example, a newly listed futures contract may have such small trading volume that there can be a large jump in futures prices compared to spot prices. Only after volume gradually increases over time will the spot and futures price changes move closely together.

- **The basis should be relatively stable**. The "price basis" is the difference between the futures price and the spot price. The size of this difference is one measure of the risk of hedging. Noncommercial traders are almost solely interested in the expected direction of price movements. In contrast, commercial traders that have opposite positions in spot and futures prices are primarily interested in the stability of the basis.

[60] See, for example, Working, H., "Hedging Reconsidered," *Journal of Farm Economics*, 35, 1953, pp. 544-561, or Houthakker, H., "Normal Backwardation," Chapter 7, Wolfe, J. N., ed., *Value, Capital, and Growth* (Chicago: Aldine Publishing Co., 1968), pp. 193-214.

An Example of a Short, or Selling, Hedge Using Actual Prices

Successful futures markets must have active participation by "hedgers," or "commercials," who use the futures market to offset an existing or anticipated physical position, in an attempt to limit risk or to lock in a cost or profit margin. For example, a jobber may buy 42,000 gallons of heating oil on July 15, 1996 at a price of 57.5 cents per gallon and put it into storage. He expects to sell it to customers during the winter and may want to protect himself from inventory devaluation. He might sell (put on a "short hedge") a heating oil futures contract for December delivery, for 42,000 gallons, on July 15 at a price of 58.79 cents per gallon. On, say, October 15, 1996 he will buy back his December futures contract at 71.20 cents per gallon. The price of the futures contract has risen while spot prices have also risen to 71.44 cents per gallon. The jobber's hedge has resulted in a loss of $5212.20 ($420 for each 1-cent per gallon rise) in the futures contract and a gain of $5854.80 in the spot market, for a net gain of $642.60. He would have had a much larger net gain if he had not used the futures market, but he was willing to forgo the extra gain to protect himself from a possible very large loss if prices had declined. Also, the loss on the futures contract may have been a speculator's gain (see next sidebar).

There are several types of basis risk which can have effects on the riskiness of hedging. First, the key to minimizing risk is having a stable "price basis," which is the difference between the futures price and the spot price. The more stable the price basis is, the more likely the futures market position will result in small net gains or losses, thus minimizing the riskiness of the position. Second, besides price risk there is also "quality basis risk." If the futures contract does not exactly match the specifications of the product being hedged, then there may be an unstable relationship between the cost of the physical commodity being hedged and the futures price, increasing the riskiness of the position. Third, there is "location basis risk." The heating oil futures contract specifies delivery in New York Harbor. If the relationship between the price difference between New York and the price where the physical product being hedged is located is unstable, this would also increase the riskiness of the futures market position.

It is important to note also that, while the futures contract itself could be used as a delivery mechanism, in practice deliveries occur very infrequently. Most short contracts, for delivery at a future date, are liquidated in a manner similar to this example, where the seller buys back a contract. Using futures contracts as delivery devices involves numerous complications. For example, when the December heating oil futures contract expires at the end of November, the buyer then decides at what time during December he will call for delivery from the seller. The transaction then corresponds to what is called an "any" cash market price, referring to any time during the month. This contrasts with the "spot," or "prompt" price which refers to delivery within 1 to 10 days. The uncertainty of delivery times and confusion about what prices are actually being used causes most companies to liquidate their futures position before their contracts expire.

While in practice the different types of basis risk, cash market prices and delivery possibilities complicate the hedging decision, they do not obscure one of the fundamental concepts of hedging, which is that a company will ask itself, "How much price risk are we willing to accept, and is it worthwhile to use the futures market to try to minimize that price risk?"

- **Hedgers want more than to minimize price risks. They want to use futures markets to maximize profits**. Most companies don't hedge their entire inventories. Even when they do hedge, they don't take all their futures positions at one time and simply hope that their risk will be exactly offset. Companies often take their total futures positions gradually. A profit-maximizing company may take a futures position by observing price trends. "Long hedgers," i.e., commercials who buy futures contracts, will buy futures during periods of declining prices and "short hedgers," i.e., commercials who sell futures contracts, will sell futures contracts during periods of extended price rallies.

This paper considers each of these factors below, and discusses how each factor might contribute to the slowdown in futures trading volume.

Petroleum Futures Market Trading Volume Slowed in 1996

Energy futures were traded on at least 20 exchanges in the 19th century, and there were numerous attempts to trade them early in this century. Mainly due to relatively small price fluctuations through most of this century, energy futures markets were unsuccessful until 1978. Today, the largest energy futures market in the world is the New York Mercantile Exchange (NYMEX). Their markets include heating oil futures contracts since 1978, crude oil since 1983, and unleaded gasoline since 1984. As Figure 70 shows, petroleum and product futures market trading volume grew at a remarkably rapid rate in the 1980's. Crude oil futures accounted for the bulk of the growth.

Overall trading growth in petroleum and product futures has slowed considerably during the 1990's, as shown in Figure 6-1. One important reason is that commercial traders have historically been attracted to futures markets as a device for hedging their price risk. But, the first factor above stresses the importance of having a futures contract that closely matches the commodity being hedged.[61] Unleaded gasoline futures illustrate this point. Heating oil and propane futures contracts are used to hedge a fairly narrow range of product specifications. In contrast, unleaded gasoline futures are specified in terms of reformulated gasoline but must serve as a hedging device for numerous types of reformulated, oxygenated, and conventional gasolines, and which have been subject to changing regulatory requirements. The fragmented gasoline market causes great uncertainty as to how closely futures prices will follow the spot prices of the type of gasoline being hedged, which may have very unstable relationships with each other, reflecting regional supply and demand differences. That uncertainty has led to a slowing in trading volume in unleaded gasoline futures. After annual increases in gasoline futures trading volume of 60 percent as recently as 1988 and 36 percent in 1989, trading volume actually decreased by 5.3 percent in 1995 and another 0.5 percent in 1996.

Even as seemingly obvious a point as having a well-defined futures contract can be deceptive in futures markets. If a contract has become established, it may be extremely difficult to start a similar contract, even if the new contract unquestionably gives a better specification of the spot commodity. A good example of this again comes from the gasoline futures market. When trading in gasoline futures began on the New York Mercantile Exchange (NYMEX) in 1981, the contract specified leaded gasoline. As it became apparent that unleaded gasoline would eventually sell far more than leaded gasoline,[62] the NYMEX in 1984 also listed an unleaded gasoline futures contract. But, as sales of unleaded gasoline grew, trading volume in the new unleaded gasoline futures went nowhere, even as the NYMEX encouraged traders to switch out of the leaded gasoline contracts. Traders were willing to accept the leaded gasoline specifications to hedge unleaded gasoline, because the trading volume in the leaded gasoline was so much greater and the price differential between leaded and unleaded gas was fairly stable over time.

Eventually, the NYMEX announced that it would simply terminate trading in the leaded gasoline futures contract, and the results were dramatic. As Figure 71 shows, early in 1986 trading volume in leaded gasoline dominated unleaded gasoline, but after leaded gas futures were terminated unleaded gasoline trading volume took off. This is also an example of why duplicative futures contracts have a high failure rate.[63] Other examples abound. Gulf Coast gasoline futures on the NYMEX were unsuccessful. Although those contracts were better specified than the New York Harbor delivery contracts for certain purposes, they couldn't compete with the volume of the existing contracts.

Futures and Spot Price Correlations May Be Highly Seasonal

Another important factor in hedging decisions is the correlation of spot and futures price changes. Hedgers only rarely hold futures contracts until their expiration date to use them as a delivery mechanism. Most hedgers will buy or sell contracts and then subsequently liquidate their positions before the contracts expire, when they wish to complete their spot market transactions.[64] Before a contract expires there will be a transfer of risk from the hedger to the speculator, with no net price gains or losses, only if the basis is the same when the futures contract is liquidated as it was when the position was initiated.[65] So it is important to both long hedgers and short hedgers that spot and futures prices move

[61]The trade press has also attributed the drop in futures trading volume to everything from small futures price movements to large futures price movements. See "Stable Prices Dull 'Interest' In NYMEX Crude Futures," *Petroleum Intelligence Weekly* (December 11, 1995), p. 5, and "Extreme Volatility Rattles Industry's Trust In Futures," *Petroleum Intelligence Weekly* (April 1, 1996), p. 1.

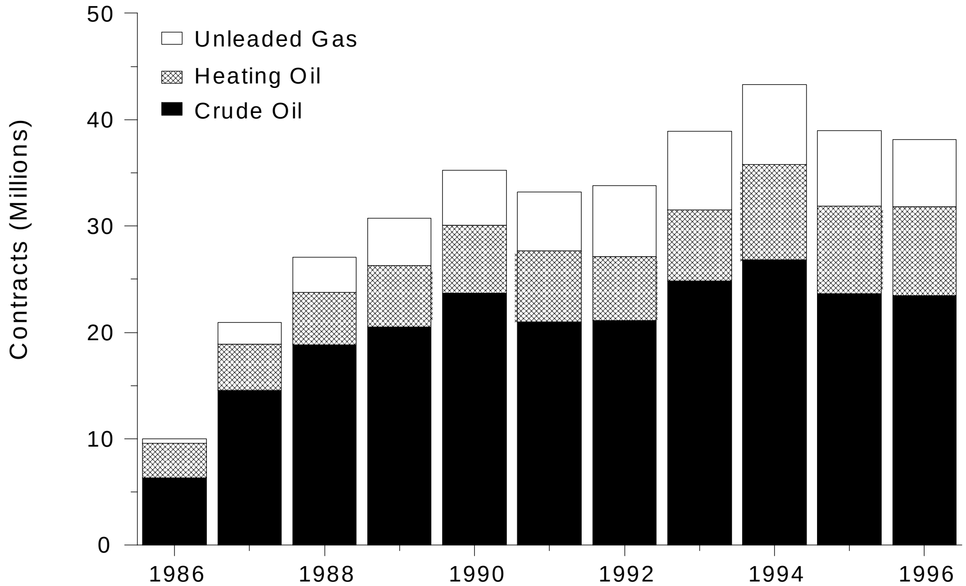
[62]In 1984 unleaded gasoline was already 59.6 percent of the total gasoline market.

[63]For a theoretical description of the growth in trading volume in new futures contracts see Dale, C., "Brownian Motion in the Treasury Bill Futures Market," *Business Economics* (May 1981), pp. 47-54.

[64]The special case of an "exchange of futures for physicals" will not be considered here, but all the same ideas still apply.

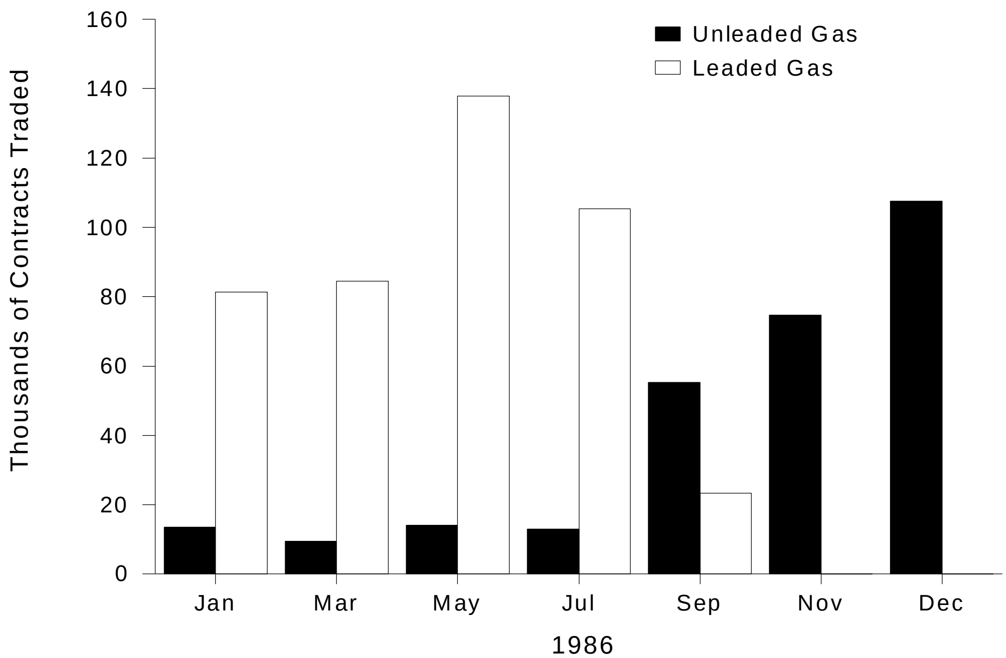
[65]For detailed examples of this, see Dale, C., "Economics of Energy Futures Markets," *Petroleum Marketing Monthly*, DOE/EIA-0380(91/09) (Washington, DC, September 1991), pp. 5-18.

Figure 70. Growth Slows in U.S. Oil Futures Trading - Annual Volume



Source: New York Mercantile Exchange.

Figure 71. Established Contracts Are Hard to Beat - Leaded Versus Unleaded Gasoline Futures



Note: Leaded gasoline futures were terminated November 1986.
Source: New York Mercantile Exchange.

together. But spot and futures price correlations, like many other aspects of futures markets, depend upon stock levels.[66]

Stocks of crude oil and petroleum products are shown in Figures 72, 73, 74, and 75. Stock levels for crude oil and petroleum products all exhibit seasonal patterns; however, these patterns are most pronounced in refined products — gasoline, heating oil, and propane — while crude oil shows a less pronounced seasonal pattern (see box, p. 108). As noted above, gasoline has problems during the year as a hedging device because of the fragmented marketplace and unstable price relationships between different types of gasoline. Heating oil and propane have the strictest definitions of deliverable grades of the commodity, so they provide the most stringent test of how stock levels affect the correlation of spot and futures prices.

Traditionally, hedgers using NYMEX take advantage of the strong price correlation between cash market transactions calling for delivery during specified future months (*forward contracts*) and futures contracts calling for delivery during the same time period. When cash market participants are highly confident as to the creditworthiness of their counterparts, and if the delivery point for their contracts is New York Harbor, similar to the NYMEX heating oil and unleaded gasoline futures contracts, in most instances there is no material difference between cash market prices and futures market prices. This holds because of the performance of *arbitrage*, i.e., taking advantages of price differentials in closely related markets, by participants who are active in both markets. If the price in one market is cheaper than in the other, these participants purchase the cheaper product and sell the more expensive product. This results in profits for the arbitragers and reduces any differences in price by increasing the lower price and decreasing the higher price. Arbitrage continues until any material differences between prices are eliminated.

More recently, there has been increased interest in the levels of inventory for petroleum products, heating oil especially. It is possible to evaluate the effectiveness of hedging increases and decreases in inventory using NYMEX futures, focussing on the current *prompt* value of the commodity. This differs from more traditional hedging in that it does not protect against price risk associated with value determined by a future commitment to make or take delivery, but instead on fluctuations in value associated with immediate delivery obligations. Clearly, the price correlation between a futures contract calling for delivery in a future month, i.e., *next* month, and *prompt* prices calling for delivery *now* cannot be as strong as that between futures and forward contracts calling for delivery during the same time period. Nevertheless, the economic analysis from hedging *prompt* with futures gives interesting results that provide useful market insights. This type of analysis is discussed below.

Large stocks improve spot and futures price correlations, which can decrease price volatility and make the futures market more effective as a hedging device.[67] Figure 74 shows that, for 1995 and 1996, heating oil stocks were at their lowest levels in March and at their highest levels at the end of the year. Similarly, Figure 75 shows that, for both these years, propane stocks reached a low in February and peaked in September. Table 11 shows that these correlations were exactly as expected from hedging theory: the correlations are high when inventories are large and low when inventories are small. As noted above, the correlations used were the spot price and the nearby futures price.[68] In practice, the futures price would be measured against a more distant spot price, depending upon the length of the hedging period (for an example of an actual hedge, see the first sidebar). The longer comparisons are subject then to various seasonal and other complicating factors. For this reason, academic research frequently analyzes these very short-term arbitrages for illustrative purposes, and this is done here in Tables 11 through 13. For heating oil, the squared correlation coefficient between the spot price and nearby futures contract price was 0.88 (perfect correlation would be 1.0) in the low stock month of March 1995 and 0.67 in March 1996, but improved to 0.95 in the high stock month of November 1995 and 0.99 in November 1996. The correlation is not quite as dramatic for propane. The squared price correlation in the low stock month of February was only 0.48 in 1995 and 0.27 in 1996, but improved in the high stock month of September to 0.52 in 1995 and 0.66 in 1996. A possible conclusion is that maintaining low stocks as part of what is loosely called "just-in-time inventory management" may lower inventory holding costs for an individual refiner, but when done on an industry-wide basis it can increase futures market hedging risks by lowering the correlation between spot and futures prices.[69]

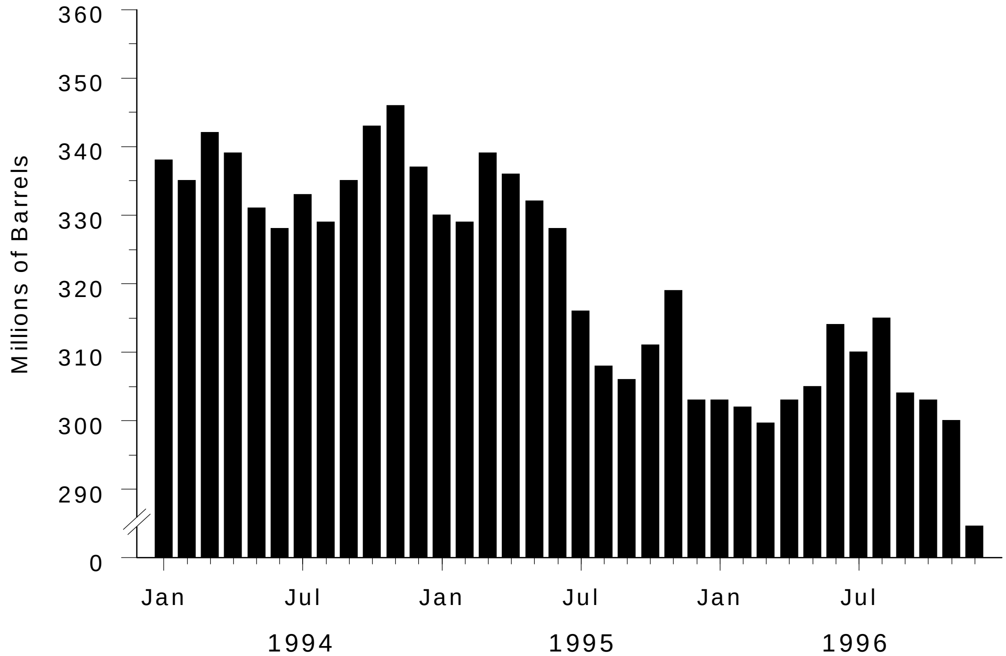
[66] Hedging theory states that spot and futures price correlations generally are proportional to the level of inventories, which has been empirically verified for many agricultural commodity futures.

[67] This paper follows the practice of using the broad term *hedging* to include both typical hedging and short-term arbitrage.

[68] The "nearby" futures contract is the one with the earliest expiration date, typically the next month.

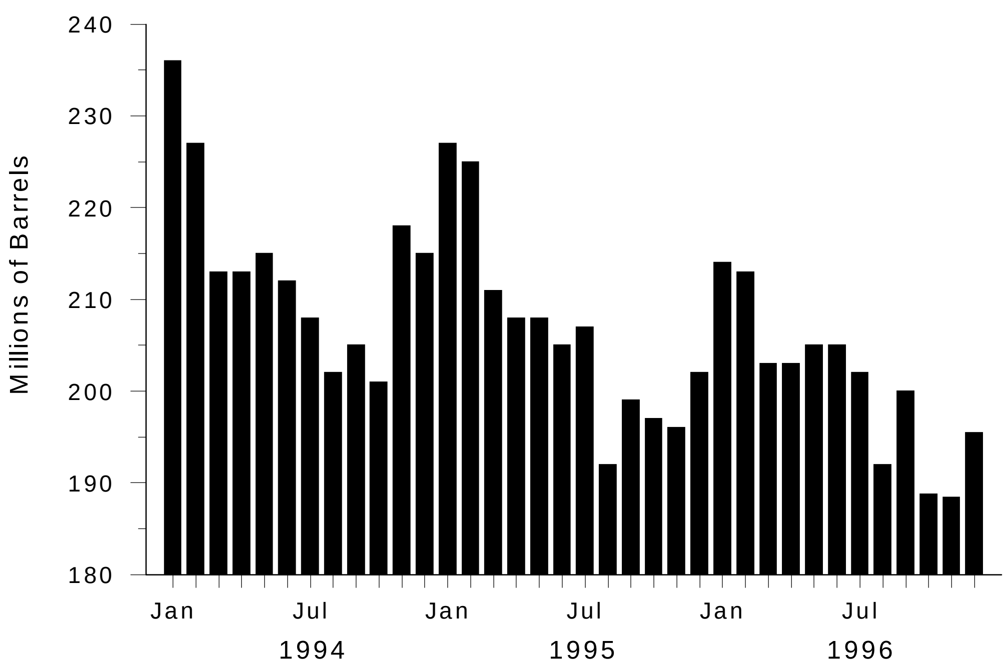
[69] Of course, in 1996 low heating oil inventories weren't necessarily all due to inventory management strategies. Large exports in September and October caused by an unusually large price differential between New York and Northwest Europe also helped to draw down inventories.

Figure 72. Monthly Crude Oil Stocks



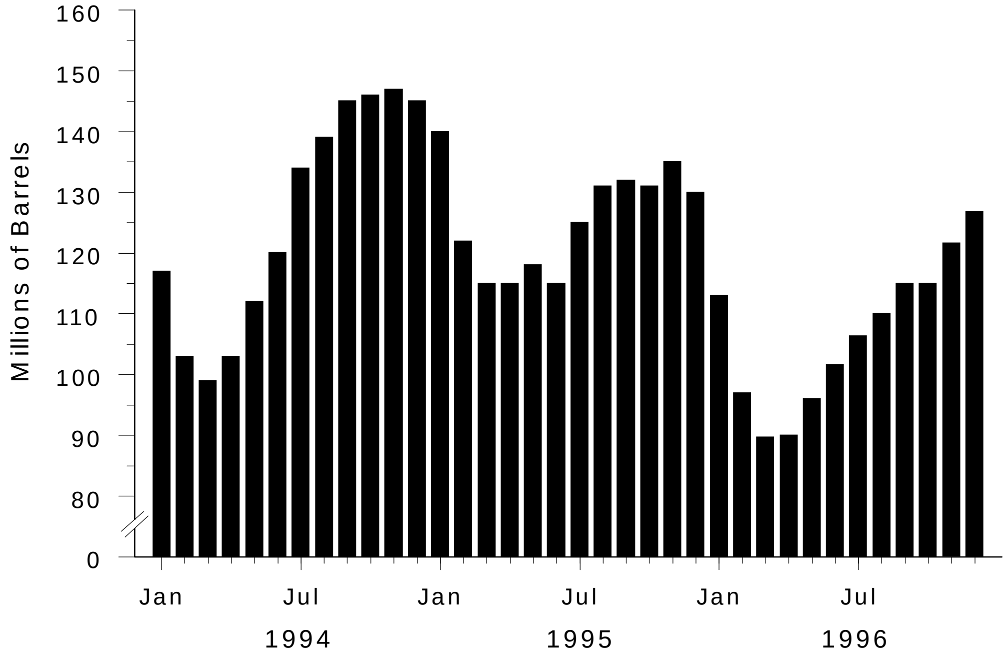
Source: Energy Information Administration, *Petroleum Supply Monthly* (various issues).

Figure 73. Monthly Total Gasoline Stocks



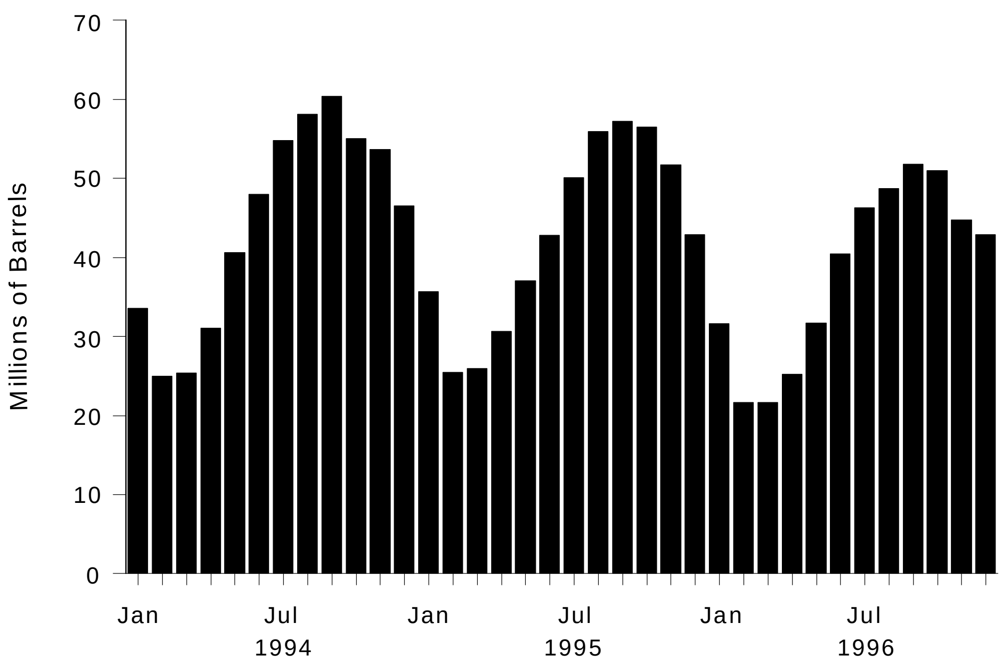
Source: Energy Information Administration, *Petroleum Supply Monthly* (various issues).

Figure 74. Monthly Distillate Fuel Oil Stocks



Source: Energy Information Administration, *Petroleum Supply Monthly* (various issues).

Figure 75. Monthly Propane Stocks



Source: Energy Information Administration, *Petroleum Supply Monthly* (various issues).

Making Money On Seasonal Price Movements -- How Easy Is It?

The existence of an energy futures market provides companies and traders the theoretical opportunity to benefit from knowledge of recurring seasonal price movements. For example, gasoline prices are typically highest during the summer driving season, while heating oil prices typically reach their highest levels in the winter. Can the futures market be used to profit from these simple facts?

In 1992, *Bloomberg Oil Buyers Guide* noted that the purchase of a December heating oil futures contract at the end of July, and its sale in mid-October, would have made a profit in 11 of the previous 13 years. That relationship still holds. Buying a contract at the end of July and selling in mid-October would have made a profit (ignoring commissions) in 12 of the 17 years from 1980 through 1996. The net gain over that period was 94.54 cents per gallon. Since each 1-cent gain represents a $420 gain on a contract that might have as little as a $1500 margin deposit, the potential gains from such trades are large indeed.

In practice, the last business day of the month is the expiration of a futures contract, and there may be increased price volatility on those days, so many companies and traders are reluctant to take positions at the end of the month. So, examining the same years from 1980 through 1996, but with the purchase made in mid-July instead of the end of the month, the result is that there would have been a profit in 11 of the 17 years (1995 was a tiny loss of only .01 cent per gallon), for a net gain of 93.28 cents per gallon.

Why, then, doesn't everyone in the industry make these trades? There are many reasons. First, most of the 93.28 cent per gallon gain was made in a few years, when there was a war or unusually cold weather, e.g., in 1990 the gain during the Gulf War was 44.92 cents per gallon. Companies may not want to tie up capital for extended periods waiting for infrequent gains, no matter how large. Second, and for similar reasons, the price doesn't move straight up even in profitable years. Futures contracts are "marked-to-the-market," or evaluated, on a daily basis, meaning that if the price drops it might be necessary to deposit additional hundreds or even thousands of dollars for each contract to maintain the position, tying up even more capital. Third, simply buying without having an anticipated sale in the future would be pure speculation, which most companies want to avoid, regardless of how profitable a trade appears to be.

This sample trade is a good illustration of information that companies and traders use to decide how to use futures markets. Marketers with existing forward contracts to sell oil might use this kind of information to decide when to establish a long, or buying, hedge. Regardless of numerous other complicating factors, such as determining a company's cash flow needs, their accounting requirements, whether to use complex trades involving futures and options, etc., the concepts of futures market trading are not mysterious. Traders and companies use their knowledge of the industry combined with the amount of risk they are willing to take to determine how to use futures markets to maximize their profits.

The Basis May Also Be Highly Seasonal

Arbitrage trading ensures that spot prices and nearby futures contract prices converge at the expiration of the contracts. Since the price basis will therefore become zero at the contract expiration, the size of the basis is a measure of the risk for a hedger. For example, a short hedger would prefer to take a position when the basis (defined here as nearby futures price minus spot price) has a large positive value, since the eventual convergence of spot and futures prices could result in a net profit on the short futures contract. As the futures contract expires, the short futures contract will eventually fall faster or rise slower than the spot price, giving the hedger a trading profit in addition to transferring his price risk. The opposite is true for long hedgers, who would prefer to buy futures contracts when the basis is a large negative value.

Table 12 shows that the basis for heating oil has a highly seasonal pattern. The data are separated into pre-Gulf War, post-Gulf War, and Entire Period (including the war). As noted above, low stocks themselves discourage any type of hedging, so hedging theory predicts relatively low levels of hedging in heating oil futures in the late winter and early spring. The basis is highly negative (meaning market "backwardation"), in the late winter months, so short hedging is discouraged at that time by the basis. As heating oil stock

Table 11. Price Correlations for Spot and Futures Prices Squared Correlation Coefficients

Month	Heating Oil			Propane		
	1995	1996	March 1991-November 1996	1995	1996	August 1992-November 1996
January	.95	.92	.97	.80	.70	.88
February	.91	.89	.87	.48	.27	.51
March	.88	.67	.78	.79	.60	.78
April	.94	.76	.85	.39	.36	.61
May	.96	.67	.89	.80	.68	.77
June	.99	.98	.97	.57	.19	.71
July	.90	.97	.98	.44	.53	.76
August	.82	.88	.97	.85	.84	.82
September	.94	.92	.95	.52	.66	.80
October	.90	.99	.98	.36	.85	.89
November	.95	.99	.98	.73	.81	.89
December	.82		.95	.68		.80

Source: Energy Information Administration calculations from Reuters and New York Mercantile Exchange data.

Table 12. Price Basis for Heating Oil Futures, Monthly Average -- Nearby Futures Price Minus Spot Price, June 1986 - November 1996
(Cents Per Gallon)

Month	1996	Pre-Gulf War	Post-Gulf War	Entire Period
January	-0.205	-2.452	0.334	-1.017
February	-4.571	-0.686	-2.038	-1.904
March	-7.182	-2.086	-2.736	-2.473
April	-8.125	-2.062	-1.700	-1.844
May	-3.357	-2.296	-0.415	-1.169
June	0.258	-0.322	0.282	0.005
July	0.322	0.325	0.361	0.345
August	0.110	0.738	0.534	0.659
September	0.070	0.734	0.623	0.766
October	0.023	0.729	0.614	0.726
November	0.237	0.342	0.798	0.650
December	0.103*	-1.429	0.944	-0.138

* = December 1995.
Notes: Pre-Gulf War = June 1986-July 1990. Post-Gulf War = March 1991-November 1996. Entire Period = June 1986-November 1996 (including war period.
Source: Energy Information Administration calculations from Reuters and New York Mercantile Exchange data.

levels become relatively larger and the basis becomes positive, short hedging is encouraged.

Table 13 shows that propane futures also have a seasonal pattern. Volume in propane futures was very small through the Gulf War period, so results are only shown for 1996 and the period 1992 through 1996. There is again a clear seasonal pattern, with backwardation in the winter and early spring. It is important to note that 1996 was an exceptional year, since below normal stock levels led to backwardation also occurring in the fall. Thus, low stocks and backwardation both discouraged short hedging in propane futures markets.[70]

[70] Before the war similar results held for gasoline futures, as the basis was positive when stocks were built in the spring and negative as stocks fell during the summer driving season. Gasoline futures results are not shown here because the numerous changes in specifications to meet Clean Air requirements after the Gulf War make it technically very difficult to match the gasoline futures contract with the appropriate spot price.

Table 13. Price Basis for Propane Futures, Monthly Average -- Nearby Futures Price Minus Spot Price
(Cents per Gallon)

Month	Nearby Futures Price Minus Spot Price	
	1996	1992-1996
January	-0.780	-0.528
February	-3.622	-1.404
March	-2.253	-1.006
April	-0.710	-0.211
May	-0.408	-0.011
June	0.124	0.238
July	0.033	0.196
August	-0.069	0.250
September	-0.593	0.191
October	-0.092	0.205
November	-0.713	0.113
December	0.523*	0.391

* = December 1995.
Source: Energy Information Administration calculations from Reuters and New York Mercantile Exchange data.

High Prices in 1996 Led to High Visibility for Futures Markets

Both crude oil prices and heating oil prices were strong in 1996. Spot prices of West Texas Intermediate crude oil rose from $17.33 per barrel in late January to $25.15 by mid-April. Spot heating oil prices rose steadily from 50.63 cents per gallon at the end of May to 76.73 cents per gallon in early October The combination of low stocks of crude oil and petroleum products and rising spot prices led to questions about the influence futures markets were having on petroleum markets.

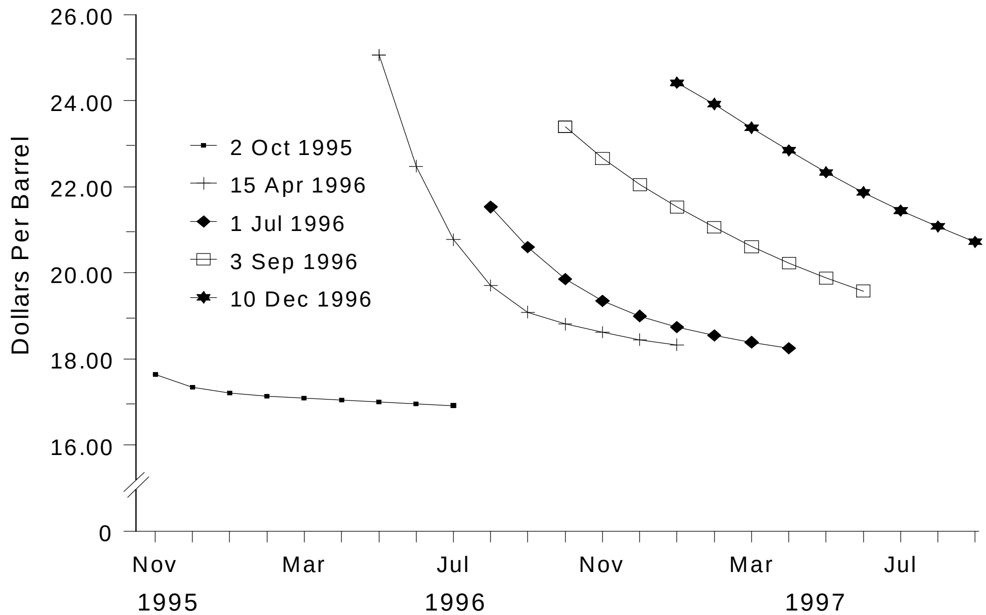
The futures markets reflected changing stock levels and expectations of an increase in supply throughout 1996. As shown in Figure 76, in late 1995 the crude oil market showed only mild backwardation, in which crude oil for delivery in distant months is priced lower than crude oil for delivery in nearby months,[71] a situation which is associated with a relatively low supply of stocks. On October 2, 1995, crude oil for delivery in November was $17.64 per barrel, while crude oil for December 1995 delivery was only 30 cents per barrel lower. But in 1996 crude oil stocks continued to fall for a number of reasons: cold weather in the spring; strong global oil demand; supply shortfalls from non-OPEC sources; and strong gasoline demand. By April 1996, the backwardation in the crude oil futures market had increased sharply. On April 15, 1996, crude oil for May delivery was $25.06 per barrel, but oil for June delivery was $2.58 per barrel lower, driven largely by expectations of imminent oil sales from Iraq. The industry did not want to increase stock holdings of crude oil that the futures market showed could fall sharply in price. In early December 1996 the backwardation decreased after Iraqi oil sales were finally announced. On December 10, 1996, crude oil futures were $24.42 per barrel for January delivery and $23.92 per barrel for February delivery. The announcement of Iraqi oil sales thus lessened the backwardation in the futures market sharply from the April structure, because of changed expectations. However, the overall price level was still much higher than in October 1995, because of lower stocks.

The extended period of backwardation in crude oil futures is frequently given as another reason for the overall decline in futures trading volume. A popular method of hedging long-term inventory positions is called "stacking and rolling," in which hedgers would extend the length of a hedge by buying back short futures contracts in expiring months and simultaneously short-selling new futures contracts in more distant months. If market backwardation continues for extended periods, this will lead to numerous situations of selling futures contracts at relatively low prices and being forced later to buy them back at higher prices. Fears of the potentially huge unprofitability of stacking and rolling from market backwardation is thus given as a reason for the drop in energy futures trading volume in 1996.[72]

[71]"Contango," by contrast, is the case of distant futures contracts priced higher than nearby futures contracts.

[72]Stacking and rolling, although with a long hedge, is frequently given as one of the primary reasons Germany's Metallgesellschaft lost nearly $2 billion in futures trading in 1993.

Figure 76. Changing Term Structure for Crude Oil Futures



Source: New York Mercantile Exchange.

While market backwardation seems at first to be a plausible explanation for the drop in futures trading volume, in reality this is not the case. While backwardation discourages short hedging from those with existing positions in the physical market, there is no reason for it to discourage long hedging, from companies who are short in the cash market and want to hedge by buying distant futures contracts. In fact, historically crude oil futures have been in backwardation more than 75 percent of the time,[73] but it was only until recently that crude oil futures trading stopped its steady annual increases.[74]

So, who does most of the hedging in futures markets? David Long[75] argues that it is traders and refiners, who are involved on both the buying and selling side of the market. On the upstream side, producers who hedge could give up profits by hedging and then having oil prices rise. On the downstream side, end users like airlines could give up profits if they hedge fuel costs by buying heating oil futures as a proxy for jet fuel, if fuel costs subsequently fall. But oil traders are involved in both buying and selling both crude oil and products, in contrast to refiners who are involved in buying crude oil and selling products, so traders are involved in both the buying and selling side of futures markets. Their decisions on how much to hedge will depend upon the current term structure of the futures markets.

Figures 77 and 78 show a variety of term structures for highly seasonal commodities. In April 1996, when crude oil futures were in backwardation because of expectations regarding the resumption of sales of Iraqi crude oil, the heating oil futures market, which is closely tied to crude oil futures, also was in backwardation for the first few delivery months. But the shape of the curve gradually switched to where more distant futures were priced higher than nearby futures, the situation called "contango." In July, the heating oil futures market was in contango in the first delivery months, reflecting ample supplies of heating oil stocks in the summer months, but it switched to backwardation in later months, reflecting the normal situation of lower inventories in the fall and winter months.

The propane futures market also showed a varying pattern. There was very little market backwardation in this thinly traded futures market in April, reflecting little expected impact from Iraqi oil sales. But in December, with both crude oil and heating oil in mild backwardation, propane

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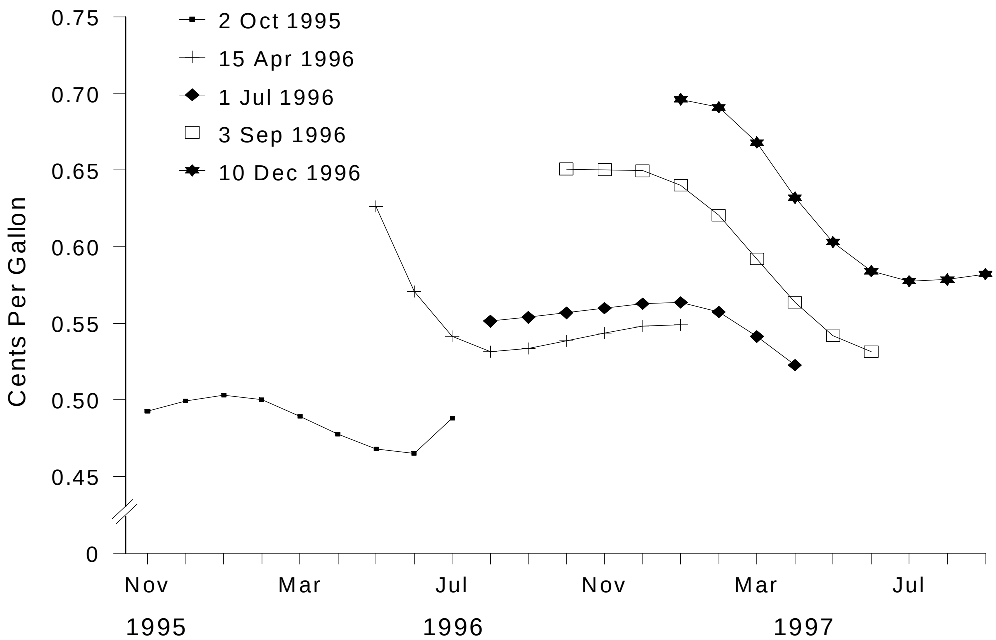
[73]Litzenberger, R. H. and Rabinowitz, N., "Backwardation In Oil Futures Markets: Theory And Empirical Evidence," *Journal of Finance*, Vol. L, No. 5 (December 1995), pp. 1517-1545.

[74]If backwardation alone caused drops in trading volume, it would be because short hedgers primarily determine the volume of trading. But a simple correlation of monthly trading volume and stock levels for crude oil from 1983 to 1996 gave a correlation coefficient of only 0.01, showing that short hedgers do not determine the trading volume. Even a more stringent test of monthly volume *changes* and monthly stock *changes* gave a correlation coefficient of only 0.15, an indication of only a very small net influence on trading volume of short hedgers.

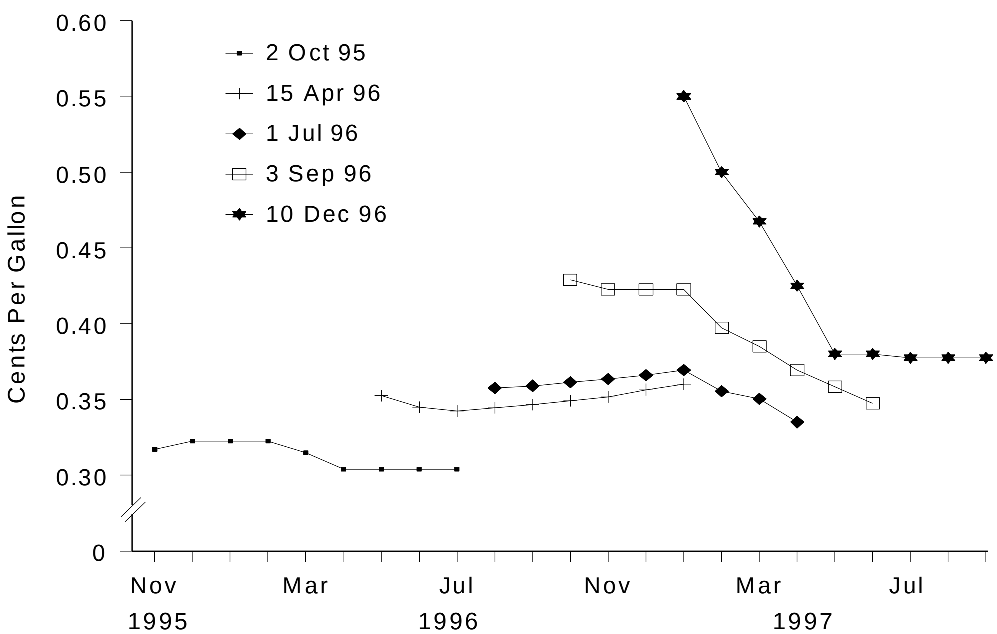
[75]Long, D., "Hedging Revisited," *Global Oil Report*, Vol. 8, No. 1, Centre for Global Energy Studies (London, UK, January-February 1997), pp. 40-54.

Figure 77. Changing Term Structure for Heating Oil Futures



Source: New York Mercantile Exchange.

Figure 78. Changing Term Structure for Propane Futures



Source: New York Mercantile Exchange.

futures were in steep backwardation because of very low seasonal propane stocks and the expectation of what bad weather in the U.S. and abroad would do to deplete those inventories. The steep backwardation on December 10 ended abruptly in contracts for delivery of propane during the spring and summer months of 1997. Clearly, the energy futures markets at any given time can give a great deal of information about the current state of stocks and market expectations.

Maximizing Profits Means Hedgers Try to Follow Price Trends

As noted in the section on the theory of hedging, hedgers try to maximize profits by observing persistent price trends. They can then sell futures contracts as prices rise, or buy futures contracts as prices fall.[76] A good example is heating oil futures which had some persistent price trends in 1995 and 1996, as shown on Figure 79.

To track the behavior of hedgers, it is necessary to use the Commitment of Trader reports compiled by the Commodity Futures Trading Commission.[77] Figures 80, 81, 82, and 83 show the percentage of the total number of long and short contracts held by large commercial traders for crude oil, unleaded gasoline, heating oil and propane futures. These graphs illustrate two points. First, large commercial traders hold the majority of energy futures contracts, averaging 60 to 80 percent of the total number of contracts outstanding. Second, there were significantly more large commercial holders of short contracts than long contracts during periods of generally rising prices. For example, in Figure 82 shorts increased faster than longs during the 1995-1996 price rise in heating oil. These results are consistent with hedging theory. Commercials were net sellers, not buyers, as prices rose, so their trading activities in 1995 and 1996 had a tendency to hold heating oil prices down.

[76]Noncommercial traders may also follow price trends, but with the opposite trading behavior. They will buy price rallies and sell price dips. See Dale, C., and Zyren, J., "Noncommercial Trading in the Energy Futures Market," *Petroleum Marketing Monthly*, DOE/EIA-0380(96/05)(Washington, DC, May 1996), pp. xiii-xxiv.

[77]The CFTC requires traders to have their brokers report their holdings if they have more than 300 futures contracts for any delivery month of crude oil, 250 contracts of heating oil, or 150 contracts of gasoline. Those reporting levels may change if total volume of trading in each type of contract changes.

1996 Brought Attention to Heating Oil

Low stocks and high prices of heating oil generated considerable attention in the fall of 1996. There were questions about the role of low stocks and the possible role of futures markets in causing high prices. In response, the Commodity Futures Trading Commission compiled the data shown on Figures 84, 85, and 86. Figure 84 together with the prices on Figure 79 show typical hedging behavior. In the summer of 1995, the basis was very narrow and this had a minimal effect on hedging decisions. But prices in July were near seasonally low levels, so commercial net positions for large traders[78] were net long in summer 1995, as large commercial traders bought during periods of declining prices. As the year progressed and prices rose, large commercials sold into the price rise and became net short. Noncommercials showed the opposite trading patterns.

In 1996, low stocks coincided with higher prices in the May through October period that were never as low as the 1995 prices, so that large commercial traders were never net long. Again, however, they generally sold and became increasingly net short as prices rose into the fall of 1996.

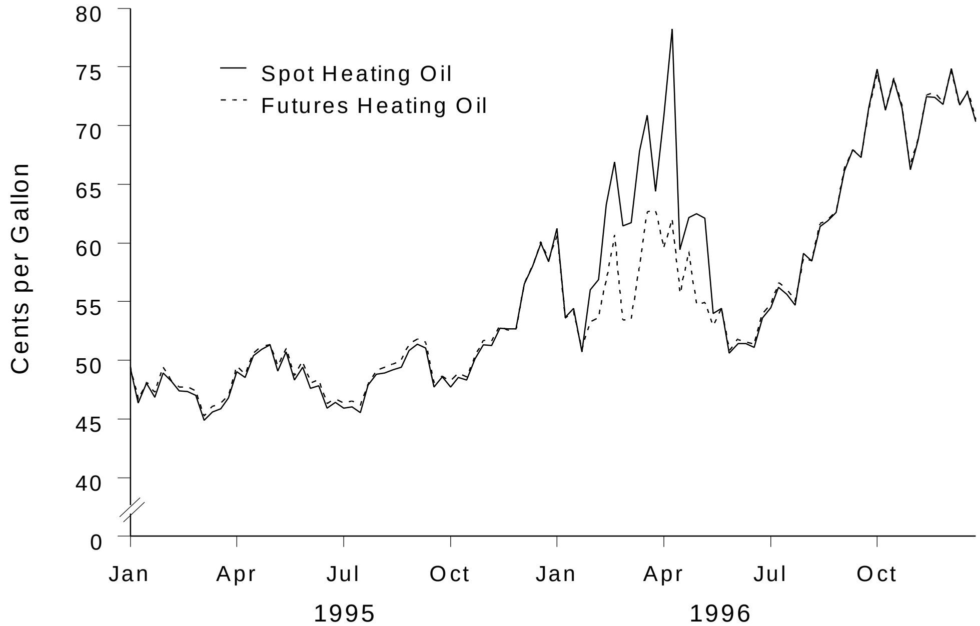
Proponents of the view that refiners engaged in a low stockholding conspiracy and misused the heating oil futures market will have to explain carefully the message of Figures 79, 85, and 86. Those graphs show that large commercial traders in general and refiners in particular were heavy net sellers of heating oil futures at a time of rising prices, which would have the effect of slowing the price increases. For example, Figure 86, which shows total rather than net positions, indicates that both long and short hedging were relatively small when stocks were low in the Spring of 1996. Refiners held more short positions throughout the May to October 1996 period, and they greatly increased their short positions as prices rose in the fall. This is exactly the result that would be expected if the futures markets are functioning efficiently and refiners are behaving in accordance with well-established hedging theories.

Announcement Effects Are Small and Short-Lived

One other possibility for the decrease in the volume in energy futures trading is for traders to be wary of

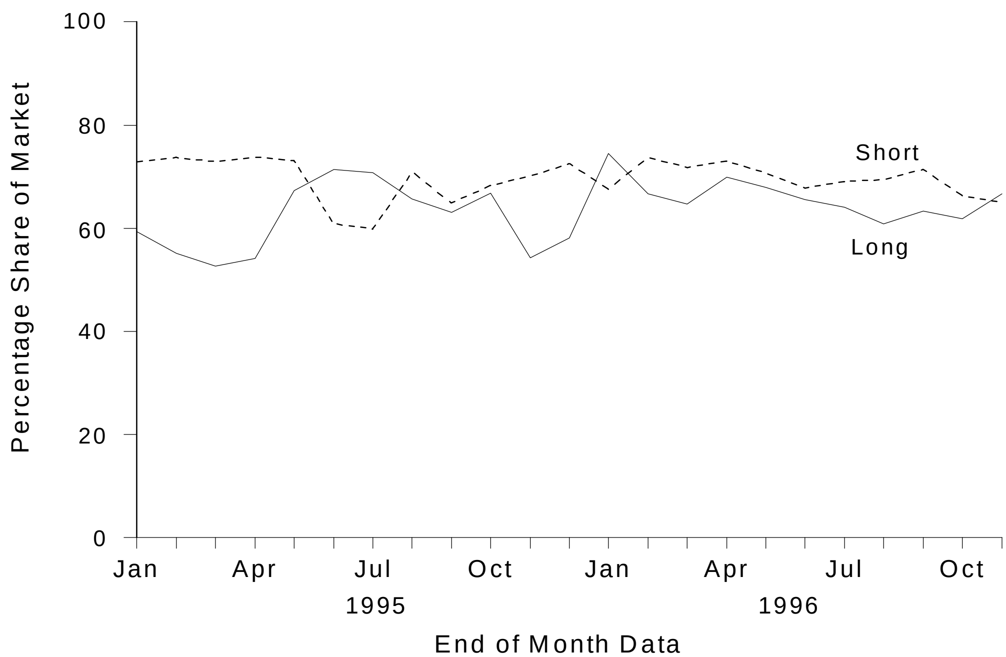
[78]Net positions are total long contracts minus total short contracts, so a positive number on Figure 84 means a net long position.

Figure 79. Spot and Futures Heating Oil Prices - End-of-Week Closing Prices



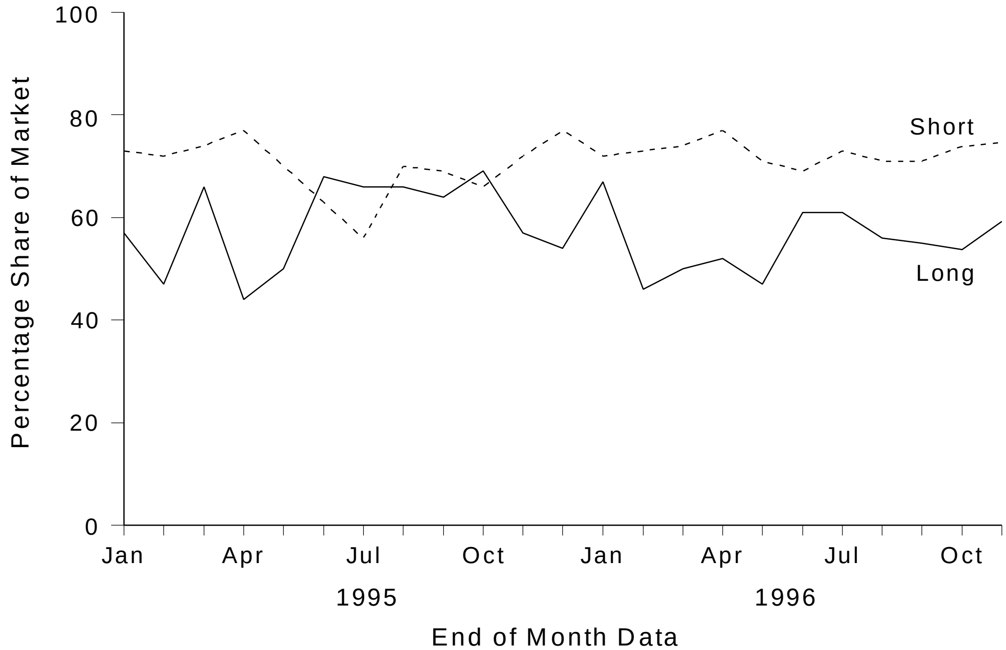
Sources: **Futures Prices:** New York Mercantile Exchange. **Spot Prices:** Reuters.

Figure 80. Large Commercials Share of Open Interest - Crude Oil Futures



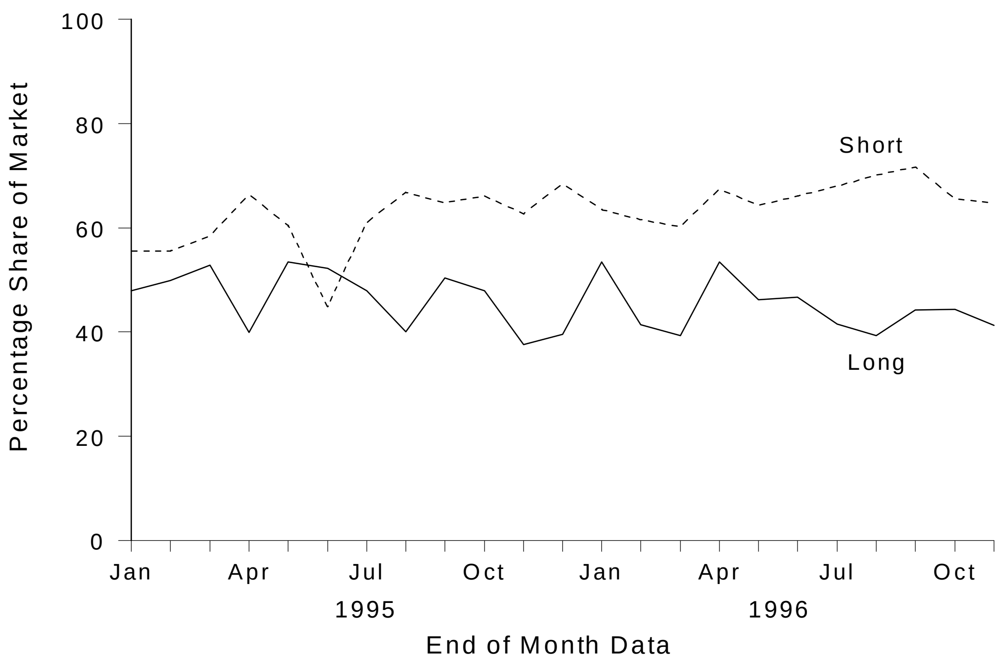
Source: Commodity Futures Trading Commission.

Figure 81. Large Commercials Share of Open Interest - Unleaded Gasoline Futures



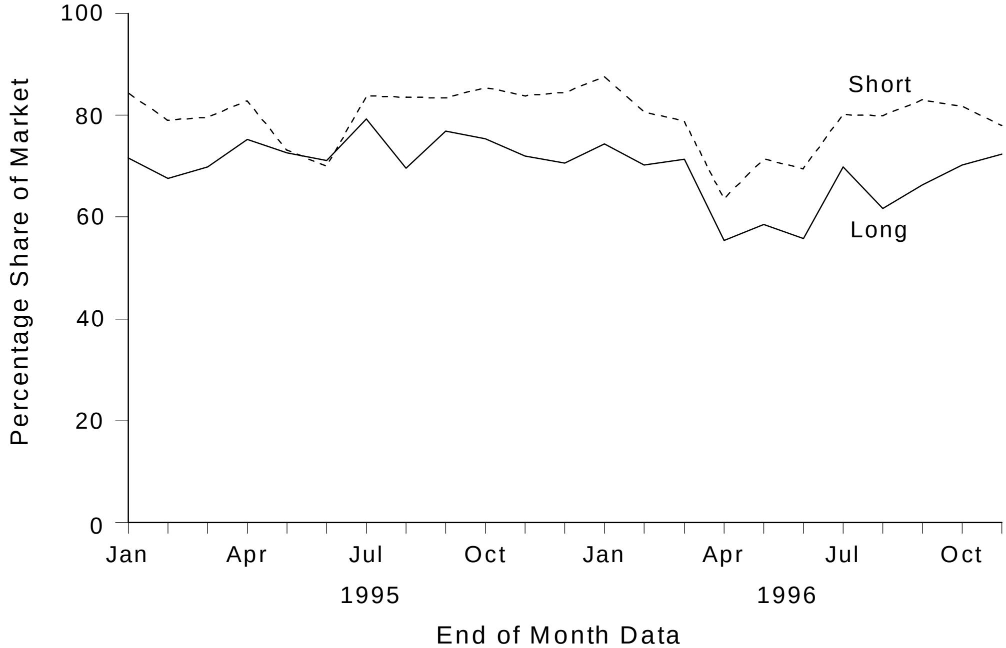
Source: Commodity Futures Trading Commission.

Figure 82. Large Commercials Share of Open Interest - Heating Oil Futures



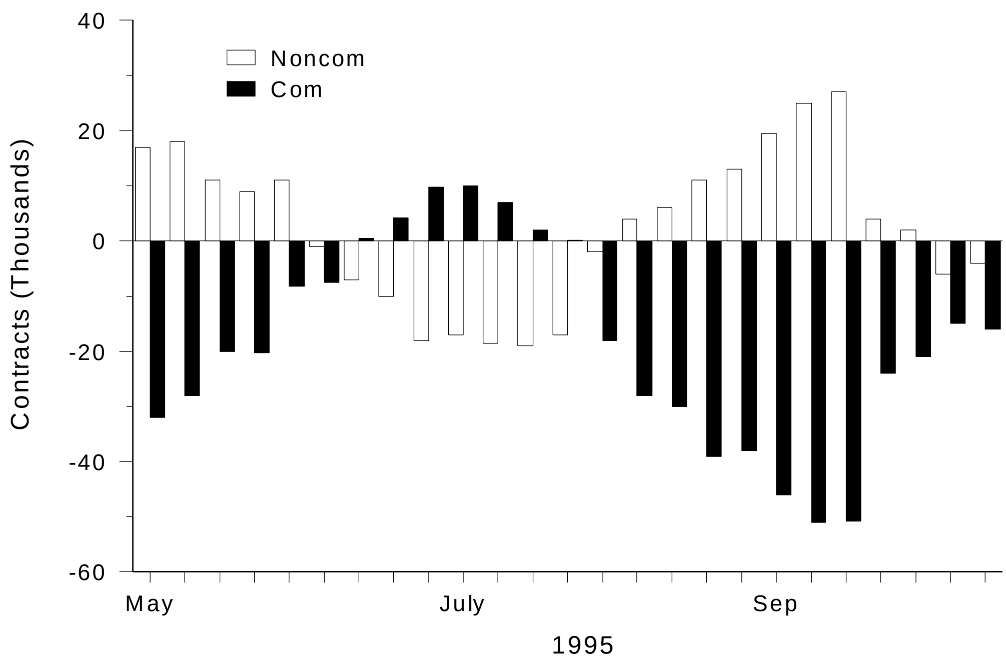
Source: Commodity Futures Trading Commission.

Figure 83. Large Commercials Share of Open Interest - Propane Futures



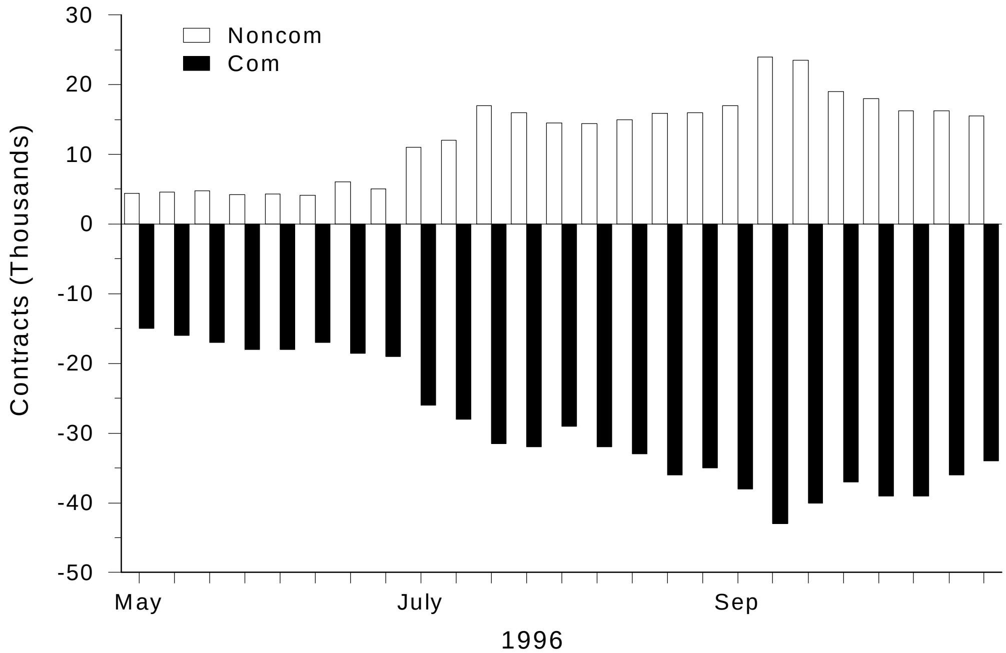
Source: Commodity Futures Trading Commission.

Figure 84. Heating Oil Net Futures Holdings - End-of-Week Large Positions, May - October 1995



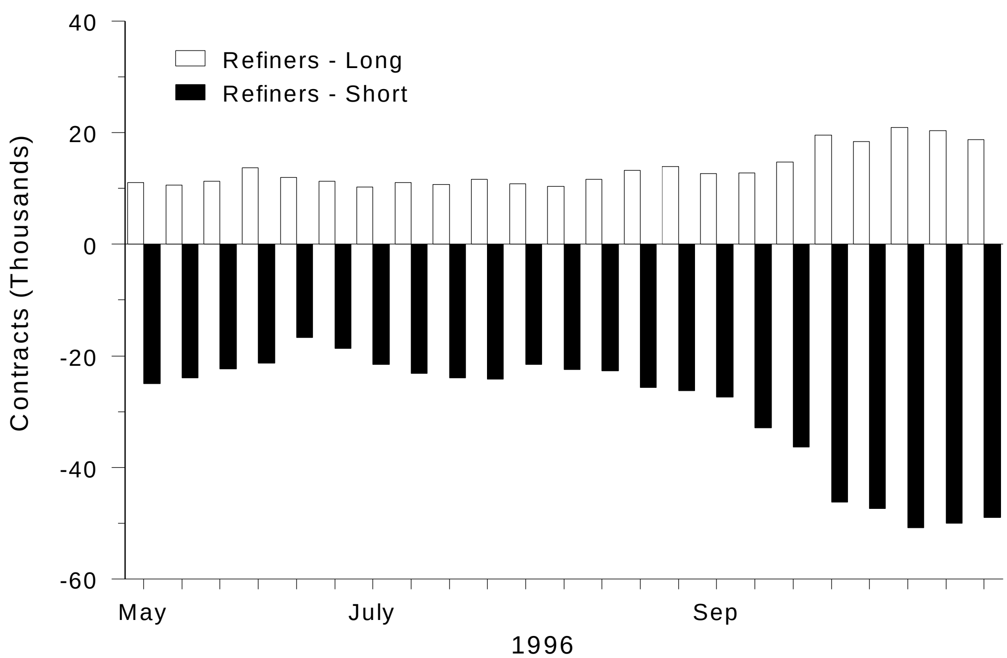
Source: Commodity Futures Trading Commission.

Figure 85. Heating Oil Net Futures Holdings - End-of-Week Large Positions, May - October 1996



Source: Commodity Futures Trading Commission.

Figure 86. Refiners Holdings of Heating Oil Futures - End-of-Week Large Positions, May - October 1996



Source: Commodity Futures Trading Commission.

"announcement effects." For example, every week the American Petroleum Institute (API) and the Energy Information Administration report stock levels of crude oil and petroleum products. Traders might be wary of using the futures markets if these announcements were to cause a long lasting and sharp increase in price volatility.[79] One-time announcement effects are commonly reported in the trade press. EIA tested several years of daily energy futures data to see if the weekly stock announcements have a consistent effect on price volatility.

There was a change in the reporting time of EIA stock data in 1994 that provided a convenient way to try to measure announcement effects. The American Petroleum Institute reports its data on Tuesdays at 5:00 p.m. Until February 1994, EIA reported stock levels at 5:00 p.m. Wednesday. After that time, EIA moved its reporting period earlier, to 9:00 a.m. Wednesday. These changes permitted a variety of statistical tests to compare the effects of each announcement on price volatility. Few consistent announcement effects were detected over the period January 1991 through May 1996, a period chosen to cover both EIA reporting times. Opening and closing prices were used to examine price volatility, day-to-day price changes, same day close versus open price changes, and opening price versus previous day's closing price. The measurable statistical effects were very weak, and it was not possible to distinguish between effects caused by API and EIA.[80] The announcement effects did not last long enough to be detected by the use of only opening and closing, and sometimes high and low, prices. There is considerable anecdotal evidence in the trade press to indicate that traders do react to stock level reports, but those reactions clearly subside very quickly and occur infrequently enough to be statistically undetectable as long-term consistent effects.[81] Therefore, they can be dismissed as a possible cause for the decrease in energy futures trading volume over the entire time period.

[79]For example, in the Eurodollar market, volatility in the 5-minute interval after the Government releases the monthly unemployment report is roughly 87 times the normal 5-minute volatility. See Ederington, L. H., and Lee, J. H., "How Markets Process Information: News Releases and Volatility," *Journal of Finance* 48 (September 1993), pp. 1161-1191.

[80]Regressions were used with time series of daily data over the time period from 1991 thru May 1996, with the data subdivided when EIA changed its reporting time in February 1994. Various combinations of reported stock levels, differences between API and EIA stocks, and deviations from historical stock levels were used to describe different measures of volatility. Autoregressive conditional heteroskedasticity (ARCH) models were estimated when necessary. Even these sophisticated techniques produced only weak statistical evidence of announcement effects.

[81]This result is consistent with results for securities markets. Analyzing data available every second, volatility after scheduled announcements usually returned to normal after 30 minutes, and volatility after surprise announcements returned to normal after only 2 hours. See Ederington, L. H. and Lee, J. H., "The Short-Run Dynamics of the Price Adjustment to New Information," *Journal of Financial and Quantitative Analysis* 30 (March 1995), pp. 117-134.

There are other reasons for unpredictable price movements, especially near the expiration of contracts.[82] But none of these effects has been shown to be either recurring or long-lived, so their effects on the overall drop in energy futures trading volume has been minimal.

Noncommercial Trading -- No Cause for Alarm

Noncommercial trading is an important part of any futures market. Speculators provide liquidity for hedgers, i.e., they provide enough volume for hedgers to enter and leave the market without unduly disturbing the price. In 1996 there was much discussion in the trade press about how noncommercial traders might be disrupting the futures markets. Those ideas were debunked, however, by David Long[83] and Dale and Zyren (see footnote 76). Long presented a theory which showed why commercial traders would buy heavily during periods of price declines and sell during price rises, with noncommercials behaving in exactly the opposite way. He hypothesizes this behavior because commercial traders change their price expectations more slowly than speculators. Dale and Zyren provided empirical support for Long's theory, by analyzing data for large traders collected by the Commodity Futures Trading Commission. They also drew the following conclusions: First, noncommercial traders follow price trends, they don't set them. Second, noncommercial traders are likely to switch between markets quickly, which may result in amplifications of existing price trends. Since these conclusions are to be expected from noncommercials in any futures market, there is no reason to believe that their behavior had anything to do with the slowing of overall trading volume in petroleum futures markets.

The Future Could Become More Complicated

This paper has concentrated only on futures markets. In practice there are a myriad of new and increasingly complex instruments available for hedgers and speculators, such as options on futures, crack spreads, and swaps. These devices are beyond the scope of this article. It is difficult to get data

[82]For examples of end-of-contract effects for crude oil and heating oil, see Dale, C., "The Effects of Energy Futures Markets on the Worldwide Marketing of Oil," in *Proceedings of the Fourteenth Annual International Conference, International Association For Energy Economics*, Honolulu, HI, Vol. II (July 8-10, 1991), pp. 786-795.

[83]Long, D., "What Drives Oil Futures? Hedging or Speculation," *Global Oil Report*, Vol. 7, No. 4, Centre for Global Energy Studies (London, UK, July-August 1996), pp. 36-50.

on all of these new areas, and also difficult to analyze how some companies could use several of them at once.[84] But to the extent that these instruments are substitutes for futures contracts, their increasing acceptance could also result in a slowing in the growth of petroleum futures trading volume.

Conclusions

This chapter has examined the fundamental behavior of energy futures markets and reached the following conclusions.

- The petroleum futures markets functioned normally and effectively in 1996. Commercial and noncommercial traders behaved as predicted by long-established hedging theory. There is no evidence that large funds of money from noncommercial traders have been setting the price of crude oil or petroleum product futures. In the memorable phrase of analyst David Long (see footnote 83), "the forces which drive futures prices have more to do with the fundamentals than the funds."

- Trading volume in energy futures has fallen off for a variety of reasons. Unleaded gasoline futures are an imperfect hedge for the greatly segmented gasoline market. Low stocks of crude oil and petroleum products tend to discourage hedging because the relationship between futures prices and spot prices becomes less stable.

- Steep backwardation in prices, where future month contracts have lower prices than nearby contracts, is not an explanation for the drop in futures trading volume. Historically, the crude oil futures market has been in backwardation more than 75 percent of the time and, until recently, crude oil futures continued to make new volume records.

- Commercial traders in general, and refiners in particular, were net sellers of heating oil as prices rose. This behavior does not support a theory of a conspiracy to keep stocks low and create price backwardation; contrarily, the additional selling pressure from refiners and other commercial traders would have the effect of mitigating price increases.

- Announcements of stock levels by the American Petroleum Institute and the Energy Information Administration do not have large and significant effects on futures prices, so those announcements did not contribute to the slowdown of trading volume in energy futures.

[84] In fact, large integrated oil companies may increasingly decide that they are "self-hedged," i.e., parts of the company may be long in physicals and other parts short in the physical market, so on a company wide basis the need to use futures markets might be minimal.

7. U.S. Refining Cash Margin Trends: Factors Affecting the Margin Component of Price

Gasoline prices rose rapidly in the spring of 1996, renewing interest in petroleum market dynamics. Since gasoline price has a major influence on refinery cash margins, these increases raised concerns about refiners earning excess profits. This chapter focuses on refinery cash margins over the past decade to determine what factors have influenced margin fluctuations. It concludes by looking at refinery cash margins in the spring of 1996 with an understanding of margin performance over the past decade to provide perspective.

Introduction

While there are different kinds of refining margins, this chapter focuses on cash margins. The refining cash margin per barrel of crude oil (Figure 87) represents all product revenues minus the costs of feedstocks (crude oil plus other feedstocks) and minus other operating costs per barrel of crude oil. Margins at U.S. refineries are affected over time by crude oil and product markets. But they also vary according to facility configuration (complexity), scale, and efficiency, the nature of the crude processed, and the region where the facility is located. In addition, margins can be affected by regulations such as the Clean Air Act Amendments of 1990 (CAAA) that required changes in product specifications to produce cleaner fuels.

Three refinery types are used to explore the historical cash margin trends for the U.S. refining industry: two typical Gulf Coast refineries and one East Coast refinery. The two Gulf Coast refineries have complex configurations containing fluid catalytic cracking, coking and hydrotreating. One is designed to process light, sweet crude oil, and the second has a larger coking unit and more extensive hydrotreating than the first in order to process high sulfur (sour) crude oils. The East Coast refinery has a fluid catalytic cracking unit, but no coking capability, and is designed to process only low sulfur crude oils.[85]

In this chapter, five margins are explored to explain historical refinery margin trends. Figure 88 shows how two of these margins, one each for an East Coast and a Gulf Coast refinery, have varied historically on a quarterly basis. This chapter uses the East Coast and Gulf Coast refinery configurations to understand those variations, addressing the seasonal changes and underlying growth in margins from 1985 through the early 1990's and their subsequent decline.

Finally, the chapter will discuss briefly the cash margins occurring early in 1996, as both crude oil and product prices rose sharply.

Refining Margin Definition

The cash margin (dollars per barrel of crude oil processed) is defined as:

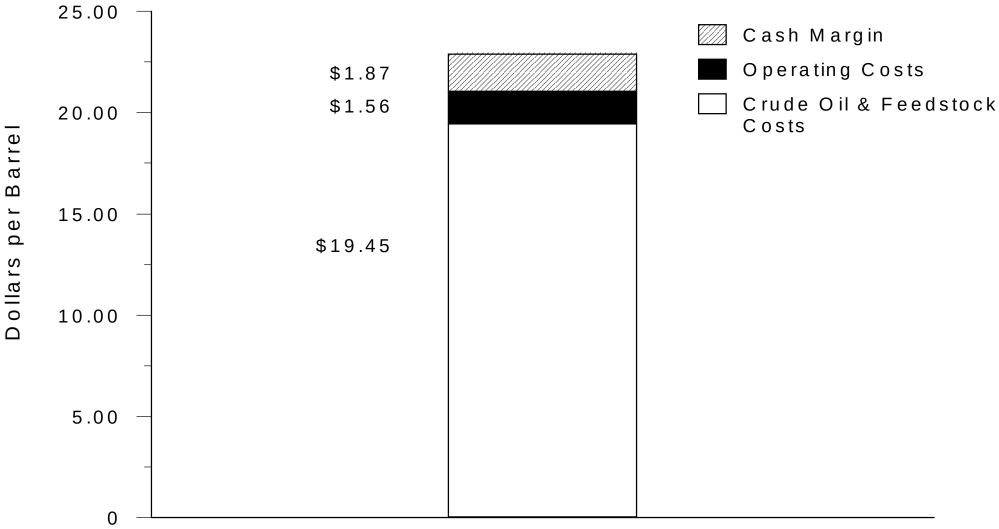
$$\begin{aligned}
\textit{Cash Margin} &= \\
&\sum_{i}^{N} (\textit{Price Product}_i \ x \ \textit{Yield Product}_i) \\
&- \textit{Crude Cost} \\
&- \textit{Other Feedstock Cost} \\
&- \textit{Fuel plus Other Variable Costs} \\
&- \textit{Operating, Maintenance Cost}
\end{aligned}$$

where,

- N represents all products produced, including gasoline, diesel fuel, heating fuel, residual fuel oil, petroleum coke and other products;
- Price product$_i$ is the spot price per barrel of product *i* received by the refiner.
- The yield of product$_i$ is the volume percent of product *i* per barrel of crude charge. It is a function of the refinery configuration, the crude type being used in the refinery, and refinery operating conditions;
- Crude cost is the price paid for a barrel of delivered crude oil;
- Other feedstock costs include costs for MTBE and purchased butane and iso-butane;

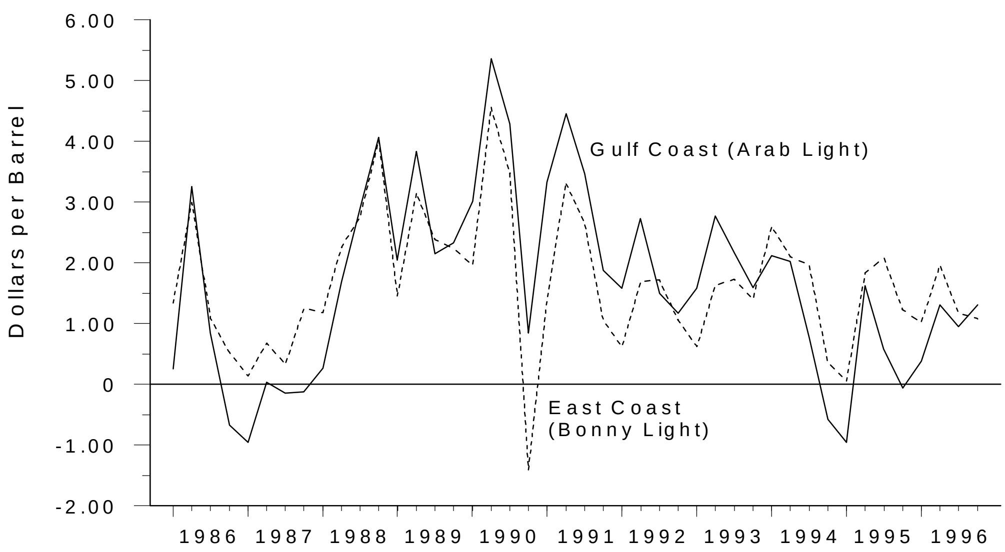
[85] While West Coast refiners experienced the same types of underlying economics, they also were preparing for unique California clean fuel specifications. As a result, they are not considered in this report.

Figure 87. Cash Margin Component of Price
(East Coast Refinery Running Brent Crude Oil, Summer 1995)



Sources: **Crude Oil, Natural Gas Liquid, and Product Prices:** Standard & Poor's Platts. **Spot MTBE Price**: *Oxy-Fuel News*, Hart/IRI Fuels Information Services (Arlington, VA). **Crude Oil Transportation Costs**: Average spot freight rates reported in *Weekly Petroleum Argus*, Petroleum Argus Limited (New York, NY), *International Crude Oil and Product Prices*, Middle East Petroleum and Economic Publications (Nicosia, Cyprus) and *Oil and Energy Trends*, Blackwell Publishers (Oxford, UK). **Refinery Yields:** EIA estimates based on crude assays from company sources and downstream process unit yields based on proprietary correlations. **Operating Costs:** EIA estimates based on company data and various public literature sources. **Cost Escalation:** Based on Nelson Farrar Index published in first issue of each month of *Oil and Gas Journal*, Pennwell Publishing Co. (Tulsa, OK). **Purchased Natural Gas Price:** Energy Information Administration (EIA), price delivered to industrial customers in Louisiana and Texas, *Natural Gas Annual*. **Electric Power Cost:** EIA, large industrial customer price, *Electric Power Annual*.

Figure 88. Quarterly Margins East and Gulf Coasts
(Based on Spot Product Prices)



Sources: **Crude Oil, Natural Gas Liquid, and Product Prices:** Standard & Poor's Platts. **Spot MTBE Price**: *Oxy-Fuel News*, Hart/IRI Fuels Information Services (Arlington, VA). **Crude Oil Transportation Costs**: Average spot freight rates reported in *Weekly Petroleum Argus*, Petroleum Argus Limited (New York, NY), *International Crude Oil and Product Prices*, Middle East Petroleum and Economic Publications (Nicosia, Cyprus) and *Oil and Energy Trends*, Blackwell Publishers (Oxford, UK). **Refinery Yields:** EIA estimates based on crude assays from company sources and downstream process unit yields based on proprietary correlations. **Operating Costs:** EIA estimates based on company data and various public literature sources. **Cost Escalation:** Based on Nelson Farrar Index published in first issue of each month of *Oil and Gas Journal*, Pennwell Publishing Co. (Tulsa, OK). **Purchased Natural Gas Price:** Energy Information Administration (EIA), price delivered to industrial customers in Louisiana and Texas, *Natural Gas Annual*. **Electric Power Cost:** EIA, large industrial customer price, *Electric Power Annual*.

- Fuel and other variable operating costs include fuel burned during processing, electricity, steam, cooling water, catalysts and chemicals required to process the crude oil; and

- Operating and maintenance costs include all personnel (operations, engineering, maintenance, supervisory, laboratory, clerical), maintenance materials, property taxes, insurance and corporate overhead.

This margin represents the cash per barrel of crude oil charge remaining to recover refinery investment (i.e., depreciation), interest expense, taxes, extraordinary cash items, and return on investment (or financial profit) (see box, p. 124). Thus, the cash margin is a key determinant of refining profitability (see Chapter 8).

Refining cash margins are complex in that they involve a multi-product process. Given a particular quality crude oil, a specific refinery produces many different products simultaneously from that crude oil. Table 14 illustrates some of the major components of a refinery margin for an East Coast refinery running Brent crude oil. The revenues are a function of both the prices of different products and the refinery yields for those products. Yield varies with refinery configuration, operating decisions, and crude oil being used. Product prices vary according to their respective markets. Operating and maintenance costs vary mainly with refinery configuration, labor costs, and price of fuel required to produce the products.

For the East Coast refinery in Table 14, gasoline contributed 59 percent to total revenues, although it only made up 53 percent of the total product barrel[86]. Gasoline is an important determinant of refiners' margin level in any given year. An entire year's financial success can be made or broken with a larger than normal variation in gasoline prices alone. Similarly, crude oil constitutes over 3/4 of all out-of-pocket refining costs. Relatively small swings in the price of crude oil, unless quickly passed through to the prices of petroleum products, can produce large changes in cash margins and, thus, in refiners' profits.

Background for Interpreting the Margin Calculation

The refinery cash margins analyzed in this chapter provide the detail required to explore specific factors that may be affecting industry margin trends. For example, this approach provides the information to explore:

- how refinery complexity affects performance;
- how different crude types affect margin levels;
- how light-heavy crude oil and product price differences impact margins; and
- how variation in regional product demand and product specifications affect margins.

While the refining cash margins presented in this chapter are not actual cash margins for the entire industry, they reflect the variations and trends experienced by U.S. refineries in general. The analysis uses realistic yield structures for major refinery types on the East and Gulf Coasts, and cost structures for each type that allow for accurate analysis of margin trends.

The East Coast refinery type is represented by a 170 thousand barrel per day, single train refinery with reforming, fluid catalytic cracking (FCC), alkylation, and hydrotreating of naphtha and middle distillate streams. The Gulf Coast refineries are similar in size, but also include coking capability. The Gulf Coast has two refinery variations, one allowing processing of light crude oils[87] with low or moderate sulfur content, and a second allowing processing of more sour crude oils by having a larger coking unit and additional hydrotreating capability, including a vacuum-gas-oil hydrotreater for the FCC unit feedstock.

The two Gulf Coast refineries are more complex and require a larger financial investment than the East Coast refineries. The larger investment is premised on the expectation that larger cash margins will be obtained to provide funds for capital recovery and an adequate return for the incremental investment. The additional investments are aimed at increasing light product yields and/or running cheaper sour, heavy crude oils. The extra coking and sulfur removal capability of the more complex Gulf Coast refiner allows this facility to convert most of the heavy materials in crude oil to higher valued gasoline and distillate, thereby improving margins. Unfortunately, the price discount for these low quality crude oils relative to light sweet crude oils is not always sufficient to allow these more complex refineries to earn competitive returns on the added conversion equipment, an issue that is discussed in detail in a later section of this chapter.

[86]The yields in Table 14 are based on crude oil input, not product output. As a result, the Table 14 product yields will be larger than yields based on total product produced.

[87]Light, sweet (low sulfur) crude oils contain a higher percentage of low boiling point materials than heavy crude oils and therefore more gasoline and distillate (high value products) can be produced from these crude oils without needing expensive upgrading equipment. In addition, the low sulfur content diminishes the need for expensive sulfur removing processes. As a result, light, sweet crude oils are considered high quality crude oils, and they command a price premium over the heavier, higher sulfur (sour) content crude oils.

Spread, Gross Margin, Cash Margin and Profit per Barrel

Four different variables are used in this *Issues and Trends* publication that are each sometimes described as "margins" by petroleum analysts: spread, gross margin, cash margin and profit per barrel. These variables all capture a measure of revenues minus costs on a "per barrel" basis. They vary in (1) what is included in the revenues (2) which costs are subtracted, and (3) the barrel basis, which usually is either barrel of product sold or barrel of crude oil input.

A **spread** is the difference between petroleum product price(s) and crude price. For example, gasoline spread is the difference between gasoline price and a specific crude oil price. In addition to single product spreads, there are multiple product spreads. For example, a **3-2-1 crack spread** assumes 3 barrels of crude oil can be used to produce 2 barrels of gasoline and 1 barrel of distillate. Thus:

3-2-1 Crack Spread ($/Bbl) = (2 x Gasoline Price
+1 x Distillate Price
-3 x Crude Oil Price)/3

Note that spread does not take into consideration all product revenues and excludes refining costs other than the cost of crude oil.

Gross refining margin is similar to a crack spread, but takes into consideration all product revenues and all raw material input costs (i.e., crude oil, oxygenates, butanes, catalysts, etc.). In this publication, the unit basis for the gross margin is barrel of product sold, rather than barrel of crude oil input. The gross margin is calculated on an individual refinery level, on a company level, or on an industry level. Gross margin is used on a company level in this document. It represents all product revenues received by a company per barrel of product sold minus all raw material costs and products purchased per barrel of product sold. Revenues reported by refining and marketing companies are mainly derived from wholesale sales (branded and unbranded rack, dealer tank wagon, and bulk commercial sales), but they generally would include some spot and retail sales as well.

Refining cash margin considers all product revenues and cash operating costs to produce the products. Like gross margins, cash margins can be calculated at a refinery level, company level or industry level. Refining cash margins are calculated both at a company level and at a refinery level in this document.

- The ***company level cash margin*** is all refining and marketing revenues per barrel of product sold minus all cash operating costs per barrel of product sold. As in the case of gross margins, revenues are derived mainly from wholesale sales with some spot and retail sales. The costs include all raw material inputs, and other cash operating costs such as fuel, electricity, labor, and general and administrative costs including corporate overhead. While most retail outlets are not owned by refining and marketing companies, some marketing and distribution costs are incurred by these companies and are included in the cash margin calculation. Costs do not include non-cash items such as depreciation.

- ***Refinery level cash margins*** in this report are calculated per barrel of crude oil input to the facility. The refinery cash margin represents revenues generated by an individual refinery selling its product at the refinery gate minus its individual cash refining costs. The revenues and raw material costs were generated from spot prices, and were calculated per barrel of crude oil charged to the refinery. The other cash operating costs are limited to refining costs (i.e., no distribution or marketing costs) and include fuel, electricity, maintenance materials and labor.

Downstream profits are also sometimes estimated on a per barrel of product sold or per barrel of crude oil input. Operating net income includes both cash costs and non cash costs such as depreciation, and downstream "net income" includes financing costs, income taxes and other non operating costs as well as non-operating revenues.

Table 14. Refinery Cash Margin Calculation
East Coast Refinery Using Brent Crude Oil Summer 1995

		Price ($/Barrel)	**Volume** (Fraction of Crude Charge)	**Revenues** ($/Barrel Crude Charge)
REVENUES	LPG	14.12	.061	0.86
	Naphtha	19.31	.026	0.50
	Premium Gasoline Conventional	23.27	.065	1.52
	Regular Gasoline Conventional	21.28	.131	2.78
	Premium Gasoline RFG	24.58	.131	3.21
	Regular Gasoline RFG	22.90	.261	5.98
	Jet Fuel	20.56	.090	1.85
	No. 2 Heating Fuel	19.55	.055	1.08
	Diesel Fuel - Low Sulfur	20.35	.111	2.26
	No. 6 Fuel Oil - 1.0% S	15.39	.156	2.40
	Total	**NA**	**1.115**	**22.87**
COST	Crude Oil FOB Cost			16.05
	Crude Transportation Cost			0.92
	Other Feedstock Cost			2.48
	Revenues minus Feedstock Cost			**3.42**
VARIABLE COST	Steam Cost			0.05
	Cooling Water Cost			0.11
	Electric Power Cost			0.22
	Catalyst, Chemicals Cost			0.14
	Total Fuel Burned			0.61
	Total Variable Cost			1.13
	Other Operating Cost			0.43
	Net Margin			**1.87**

Note: Total yield is greater than crude input alone due to additional feedstocks (e.g., MTBE and butanes) and processing gain.

Sources: **Crude Oil, Natural Gas Liquid, and Product Prices:** Standard & Poor's Platts. **Spot MTBE Price**: *Oxy-Fuel News*, Hart/IRI Fuels Information Services (Arlington, VA). **Crude Oil Transportation Costs**: Average spot freight rates reported in *Weekly Petroleum Argus*, Petroleum Argus Limited (New York, NY), *International Crude Oil and Product Prices*, Middle East Petroleum and Economic Publications (Nicosia, Cyprus) and *Oil and Energy Trends*, Blackwell Publishers (Oxford, UK). **Refinery Yields:** EIA estimates based on crude assays from company sources and downstream process unit yields based on proprietary correlations. **Operating Costs:** EIA estimates based on company data and various public literature sources. **Cost Escalation:** Based on Nelson Farrar Index published in first issue of each month of *Oil and Gas Journal*, Pennwell Publishing Co. (Tulsa, OK). **Purchased Natural Gas Price:** Energy Information Administration (EIA), price delivered to industrial customers in Louisiana and Texas, *Natural Gas Annual*. **Electric Power Cost:** EIA, large industrial customer price, *Electric Power Annual*.

Each of the refinery types represented is a single train refinery (i.e., with no unit duplication), and thus has a reasonably efficient cost structure that probably represents better-than-average real-world margin performance. Nevertheless, these representations effectively illustrate margin trends over time and allow exploration of the major factors influencing their rise and fall. Operating cost data for actual individual refineries can vary considerably, even for refineries of comparable complexity. The operating costs used in the margin calculation are process-unit based, and were derived from a variety of industry and reference economic source documents.

Crude oil throughput, other feedstock volumes, such as butanes, and product yields were varied quarterly to reflect the seasonal transitions between the high distillate demand and high gasoline demand seasons and to meet seasonal product quality specification requirements (e.g., gasoline Reid vapor pressure). Regulatory compliance costs were captured by making appropriate configuration, operating, and cost adjustments as regulations affecting product specifications changed.

In order to reflect the effect of different reformulated gasoline (RFG) market requirements after 1995, different mixes of gasoline formulations were used for the East Coast refinery calculations than for the Gulf Coast. The East Coast refineries produced 2/3 RFG and 1/3 conventional gasoline, while the Gulf Coast refineries produced 1/3 RFG and 2/3 conventional gasoline.

Spot prices (both crude oil and product) were used in deriving the Gulf Coast and East Coast refinery margins discussed and displayed throughout this chapter. Spot prices represent marginal product and crude oil being bought and sold on the market. Spot prices can vary significantly with short-term supply/demand fluctuations, and therefore probably reflect more variation in price than a company might actually experience. Most companies use a mix of contract and spot markets for both feedstock purchases and product sales. Contract market prices are usually more stable, even though many contracts use spot prices in their pricing formula.

Margin Variations

Figure 88 displays the margin calculation for the Gulf Coast refinery running a sour, moderately heavy crude oil (Arab Light) and for the East Coast refinery running a light sweet crude oil (Nigerian Bonny Light). These margins exhibit several typical variations:

- *Seasonal:* Margins peak frequently in the second or third quarters and hit their low points during the winter (fourth or first quarters);

- *Long-term:* A general upward trend underlies the margins from 1985 through 1990, followed by a subsequent weakening in margins from 1990 through 1995, with the possibility of a turnaround in 1996;

- *Regional:* The Gulf Coast refinery margins exhibit a larger variation in the underlying long-term trend than East Coast refinery margins, rising faster and overshooting the East Coast margin, then reversing and falling back below the East Coast margin by 1993.

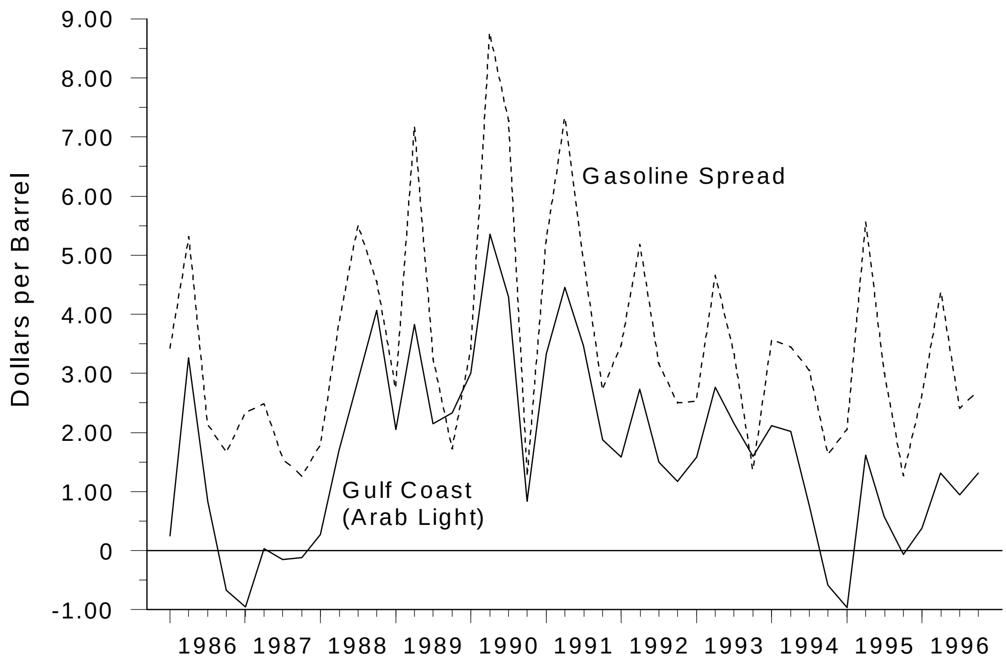
This section discusses market factors that explain these variations, including product and crude supply/demand balances, the interactions of light versus heavy product demand, light versus heavy crude availability, the availability of conversion capacity, and changing product specifications brought about by the need for cleaner fuels.

Seasonal Margin Variations Stem Mainly From Gasoline Market

U.S. refining margins are highest in the spring and summer months (second and third quarters) because they are heavily influenced by gasoline markets. Gasoline provides the highest contribution to cash margin of any single product. For the East Coast refinery processing Brent crude oil, in the example of Table 14, gasoline comprises about 53 percent of the total product slate produced and contributes about 59 percent of total revenues. The gasoline market is highly seasonal, with price spreads (spot gasoline minus crude oil prices) generally cresting in late spring or early summer as the industry prepares to meet peak driving demand, which usually occurs around June (see Chapter 2). The rising gasoline spreads are reflected in rising cash margins. Consequently, the seasonal swings of refinery margins correspond to price variation in the gasoline market (Figure 89). In fact, the spring margin increase is a primary determinant of a refiner's performance for an entire year.

Distillate has a counter-cyclical demand and price pattern from gasoline. The distillate price rise in the fall tends to moderate the margin's seasonal pattern, but it does not counterbalance the gasoline market's strong seasonal influence on refining margins. Distillate's smaller influence is primarily a result of its small volume relative to gasoline. (Distillate's share of the product barrel produced by an East Coast refinery using Brent crude oil is about 23 percent, while gasoline's share is about 53 percent.)

Figure 89. Quarterly Gulf Coast Refining Margin and Gasoline Spread
(Based on Spot Product Prices)



Sources: **Crude Oil, Natural Gas Liquid, Product Prices, and Spot Spreads:** Standard & Poor's Platts. **Spot MTBE Price**: *Oxy-Fuel News*, Hart/IRI Fuels Information Services (Arlington, VA). **Crude Oil Transportation Costs**: Average spot freight rates reported in *Weekly Petroleum Argus*, Petroleum Argus Limited (New York, NY), *International Crude Oil and Product Prices*, Middle East Petroleum and Economic Publications (Nicosia, Cyprus) and *Oil and Energy Trends*, Blackwell Publishers (Oxford, UK). **Refinery Yields:** EIA estimates based on crude assays from company sources and downstream process unit yields based on proprietary correlations. **Operating Costs:** EIA estimates based on company data and various public literature sources. **Cost Escalation:** Based on Nelson Farrar Index published in first issue of each month of *Oil and Gas Journal*, Pennwell Publishing Co. (Tulsa, OK). **Purchased Natural Gas Price:** Energy Information Administration (EIA), price delivered to industrial customers in Louisiana and Texas, *Natural Gas Annual*. **Electric Power Cost:** EIA, large industrial customer price, *Electric Power Annual*.

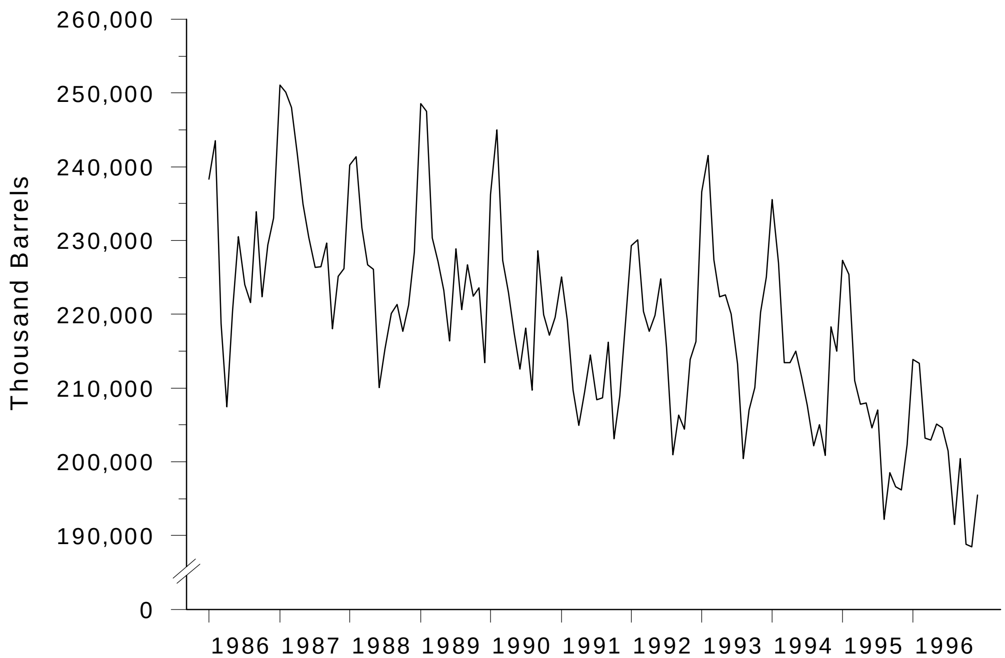
Refining margins are generally lowest during the winter quarters (fourth and first quarters) when gasoline demand and prices have fallen and inventories are building. The weather's impact on distillate prices tends to determine if the first quarter or the fourth quarter is the lowest margin quarter. Early cold weather can drive distillate prices up in the fourth quarter, pushing fourth quarter margins higher than first quarter, and vice versa (e.g., fourth quarter 1988 margins were higher than first quarter 1989 margins, but fourth quarter 1993 margins were lower than first quarter 1994.)

Seasonal swings vary in magnitude. For example, the spring seasonal increase in margins was low in 1992 and 1993. Again, the strong influence of gasoline markets on refinery cash margins can partially explain the margin behavior. Gasoline spreads also showed little seasonal climb in 1992 and 1993. In the United States, the slow growth of gasoline demand in the early 1990's coupled with strong supply kept gasoline stocks relatively high throughout the summers of 1992 and 1993 (Figure 90). The market responded with weak gasoline prices relative to crude oil. The weak gasoline spreads in those years contributed to the low seasonal swings in margins and to lower annual refining margins. The longer-term variation in world crude oil supply/demand balance seems to play a role in the strength or weakness of the product market seasonal variation, which is discussed below.

Long-Term Margin Trends Driven By Multiple Factors

In addition to seasonal factors, several long-term factors can affect margins. Such factors include crude market tightness which sometimes influences product market tightness for extended periods, the light-heavy crude oil and product supply demand balance, refining capacity utilization, and implementing the reformulated gasoline (RFG) program. However, not all of these factors had a significant effect on margins over the past decade.

Figure 90. Total Gasoline Stocks



Sources: Energy Information Administration (EIA), **1986-1995:** *Petroleum Supply Annual*, Vol. 2, Table 2. **1996:** *Petroleum Supply Monthly* (various issues), Table 2.

Product Market Tightness Can Be Related to World Crude Market Tightness

The weak seasonal increases in margins and gasoline spreads in 1992 and 1993 can be related to crude market supply/demand balance. During 1992 and 1993, the world experienced an oversupply of crude oil and products as demand worldwide languished from a recession. Petroleum demand recovered and grew substantially in 1994, but crude oil supply grew strongly as well, keeping markets from tightening very rapidly, and preventing a strong price resurgence.[88] During periods when crude markets are loose (excess supply relative to demand), product markets are less likely to tighten. The wide surplus availability of crude oil to respond to any product demand requirements can keep product price spreads relatively weak. Conversely, tight crude markets can be accompanied by tight product markets. When crude markets are tight, crude oil prices can be pulled higher by tightening product markets as happened in early 1996 when distillate demand pulled crude oil prices up at the end of winter. However, in either case, product markets do not necessarily follow in lock step. Both crude and product markets were tight in 1996, but in early 1997, crude markets loosened while product markets remained tight. If crude markets remain loose, product markets will likely follow.

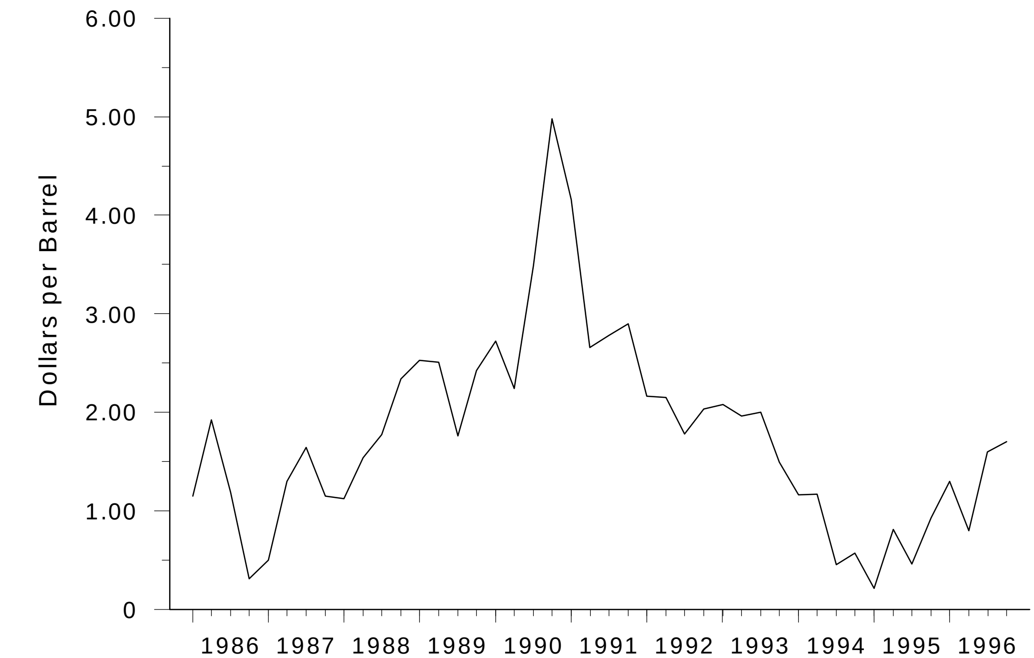
Light Versus Heavy Balances for Crude and Products Affect Margins

The underlying upward movement in refining margins from the mid-1980's until the early 1990's, and their subsequent decline, can be explained in part by the changing light-heavy balance for both crude oil supply and product demand and the availability of conversion capacity to upgrade heavy materials to light products. Over the last decade, the light-heavy price difference for both crude (Figure 91) and product (Figure 92) have tracked the increase and decrease in refinery margins.

The price differences between light and heavy crude oils and light and heavy products are among the most important variables affecting refinery margins. These differentials are the incentives for installing expensive processing facilities in a refinery, including fluid catalytic cracking (FCC), hydrocracking, coking and other residual conversion

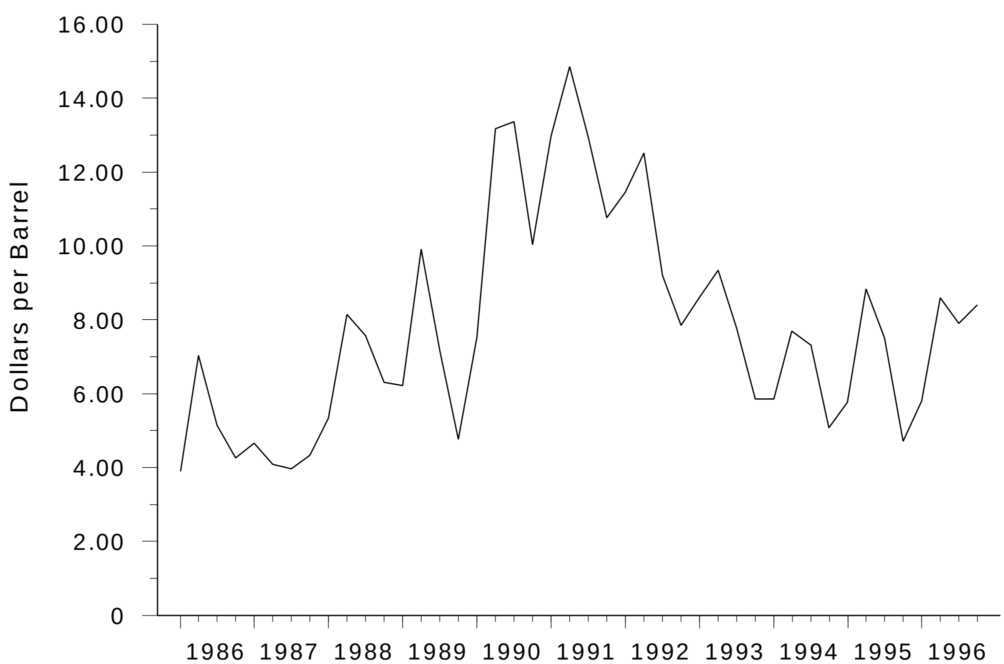
[88]The increasing, light-to-heavy crude oil supply ratio had a depressing effect on margins during the 1990's, as discussed in more detail under long-term trends. Light sweet crude supply was especially abundant during this time, and the light-heavy crude price difference continued to drop substantially, with Bonny Light crude oil falling to near parity with Arab Light crude oil in early 1995. (Despite its name, Arab Light is an intermediate crude oil based on bottoms content.)

**Figure 91. Light Minus Heavy Crude Price Difference
Spot Bonny Light - Arab Light**



Source: Standard & Poor's Platts.

Figure 92. Light Minus Heavy Product Price Difference
(Spot Gulf Regular Conventional Gasoline - 1 Percent S Residual Fuel)



Source: Standard & Poor's Platts.

facilities that convert the heavy material in crude oil to lighter, higher-valued products such as gasoline and diesel.

Crude oils vary in quality primarily based on how much heavy material they contain. In Table 15, a light, high quality crude oil, Nigerian Bonny Light, is compared with a heavier, lower quality Saudi Arabian crude oil. The Bonny Light crude oil contains only 3.4 percent of heavy bottoms fraction compared to 27.2 percent heavy bottoms fraction for Arab Heavy. The heavy material in crude oil can be made into heavy product or can be converted into light product if a refinery has the conversion facilities. The price of heavy oil products is determined in lower valued market applications where residual fuel oils compete with coal and natural gas. When demand and price of residual oil decline relative to other refined products, light crude oils become more attractive. Light-heavy product and crude price differentials increase. As the differentials increase, the incentive for refiners to install more heavy crude conversion equipment increases. But markets move in both directions. Over time, the relative demand for light and heavy products may shift, more light crude oil may become available, or refiners may install too much conversion equipment. Each of these circumstances will tend to push the light and heavy prices closer together, reducing the differential. The impact on refinery margins of variations in light-heavy differentials have had profound impacts on U.S. refiner margins over the past two decades. A brief review of this time period provides an illustration of these important margin variables.

In the late 1970's, widening light-heavy crude oil price differentials and forecasts of crude oil supply becoming heavier as product demand grew spurred a serious movement to install heavy crude oil processing facilities. At this time, domestic crude oil production was relatively constant and the mix was growing heavier (Figure 93). Crude oil prices had risen dramatically, but demand growth was still strong. Light-heavy crude oil price differentials increased, rising each time crude supply tightened. Many U.S. refiners expected import levels to grow, and they thought that additional imports would probably come increasingly from the larger world producing areas, which supplied mostly heavy sour crude. Thus, as the 1980's began, many U.S. refiners were engaged in adding residual conversion capabilities.

But from 1981 to 1986, oil markets did not evolve as forecasted. Product demand fell, and crude import requirements diminished. Product demand also fell worldwide, so the supply of light crude oil was ample at the resulting reduced crude oil demand levels. Conversion capacity planned in the late seventies was now coming on stream in the United States and Europe. Consequently, the light-heavy differentials dropped dramatically, barely covering the added variable operating cost of refineries newly equipped to run heavy sour crude oil. During the first half of the 1980's, total refining margins were low, and the small light-heavy price differentials allowed virtually no added margin for heavy crude refiners to generate return on their recently installed conversion facilities.

After the crude oil prices dropped below $20 per barrel in 1986, demand for crude oil began to grow again. Demand for heavy products continued to decline in the United States as well as in other major world oil markets (Figure 94), but at a slower rate. Addition of new residual oil conversion projects fell drastically. As Figures 91 and 92 show, light-heavy crude and product differentials began to increase in the late 1980's and grew until 1991 with corresponding improvements in refinery margins.

In the early 1990's, light-heavy differentials again declined. In part, excess world conversion capacity contributed to the decline. Two major sour crude processing facilities were begun in the United States. These projects were joint ventures of U.S. refiners and heavy crude oil exporting countries. When complete, a Lyondell/PDVSA project will increase heavy crude processing at its Houston refinery from 120 thousand barrels per day to 200 thousand barrels per day, and a Shell/Pemex project will allow its Deer Park refinery to run 100 thousand barrels per day of heavy Mexican Maya crude. Conversion capacity in Europe has also grown, but at a much more modest rate in the 1990's compared to the mid 1980's (Figures 95 and 96).

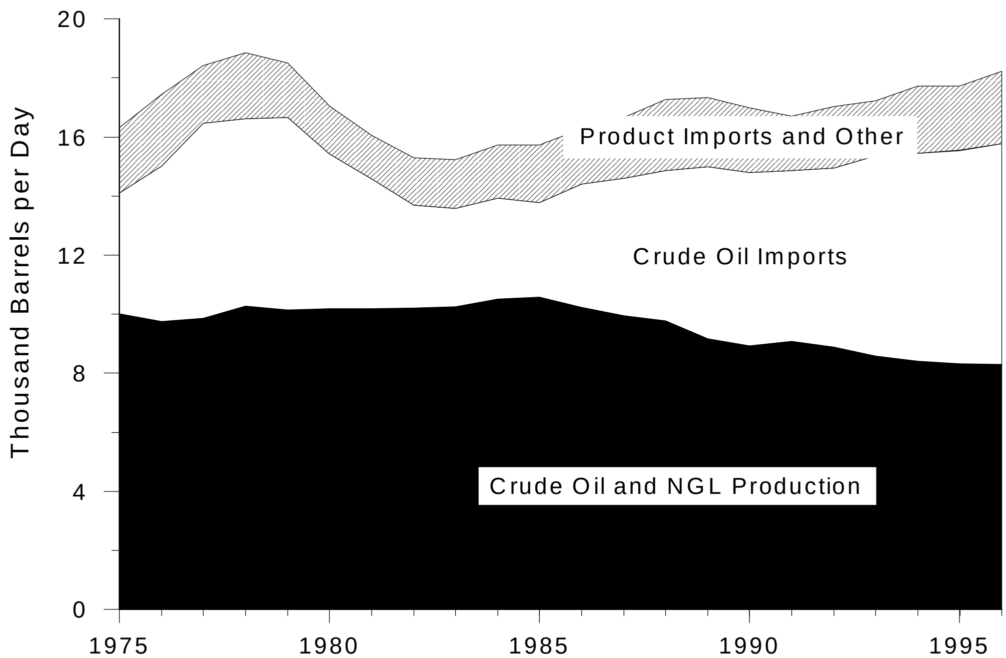
In the 1990's, conversion capacity was only part of the downward pressure on light-heavy differentials. The primary factor driving the decline was a substantial increase in light, sweet crude oil production in the Atlantic Basin market region. The largest part of the increase came from the North Sea, where production increased by 60 percent (2160 thousand barrels per day) from 1990 to 1995. West African countries and the new light sweet Cusiana area in Colombia also contributed increased supplies of light sweet crude oil. Saudi Arabia added to the growing differential by limiting production of its heavy crude (Arab Heavy) and raising its price to encourage use of Arab Super Light. This policy added increased downward pressure on the light-heavy differentials in 1994. The Saudi limitations on their heavy crude together with the glut of light-sweet crude in the Atlantic Basin drove the price differential down to the point in 1994 that the West African crude oils became attractive to the Asian market, despite the long freight haul. The trade press reported that movements from West Africa to Asia in the summer 1996 reached 800 thousand barrels per day. Since 1994, in fact, the demand pull from the Asian markets has provided some price support for the value of Atlantic Basin light-sweet crudes, in effect providing a price floor.

Table 15. Distillation Volume Percent Yields

Fuel Type	Arab Heavy	Arab Light	Nigerian Bonny Light
Light Ends	6.3	7.7	6.6
Gasoline	15.5	18.6	20.7
Kerosene	7.2	8.6	9.5
Diesel	16.2	20.3	30.6
Heavy Atmospheric Gas Oil	27.6	28.9	29.2
Bottoms (1,050 °F+)	27.2	15.9	3.4

Source: Energy Information Administration, estimates based on crude assays from company sources.

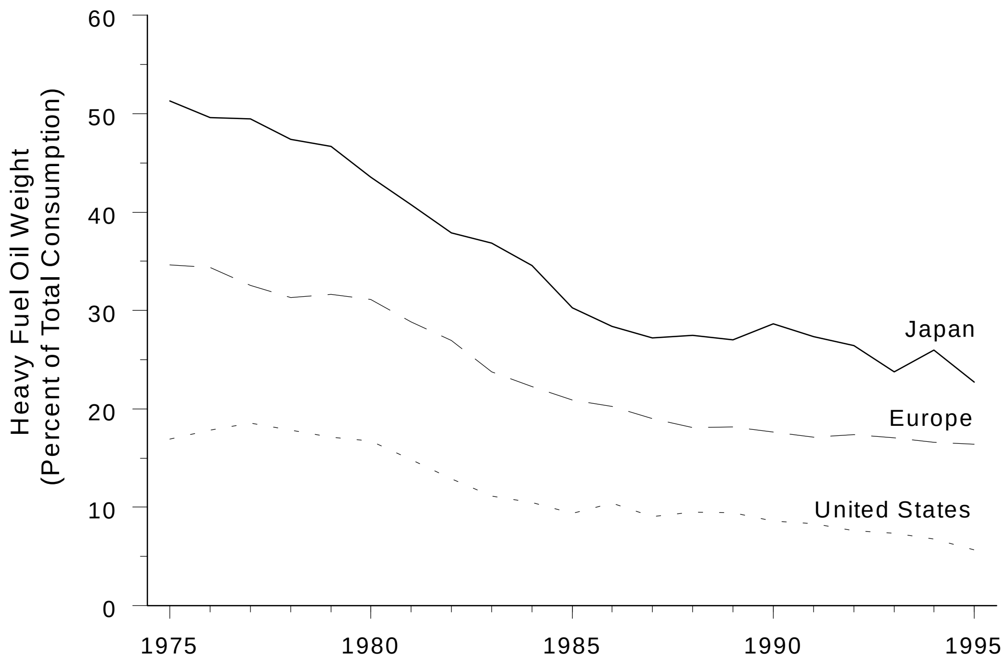
Figure 93. U.S. Petroleum Supply



Note: NGL = Natural gas liquids.
Sources: Energy Information Administration (EIA), **1975-1995:** *Annual Energy Review* (1995), Table 5.1. **1996:** *Petroleum Supply Monthly* (February 1997), Table 5.

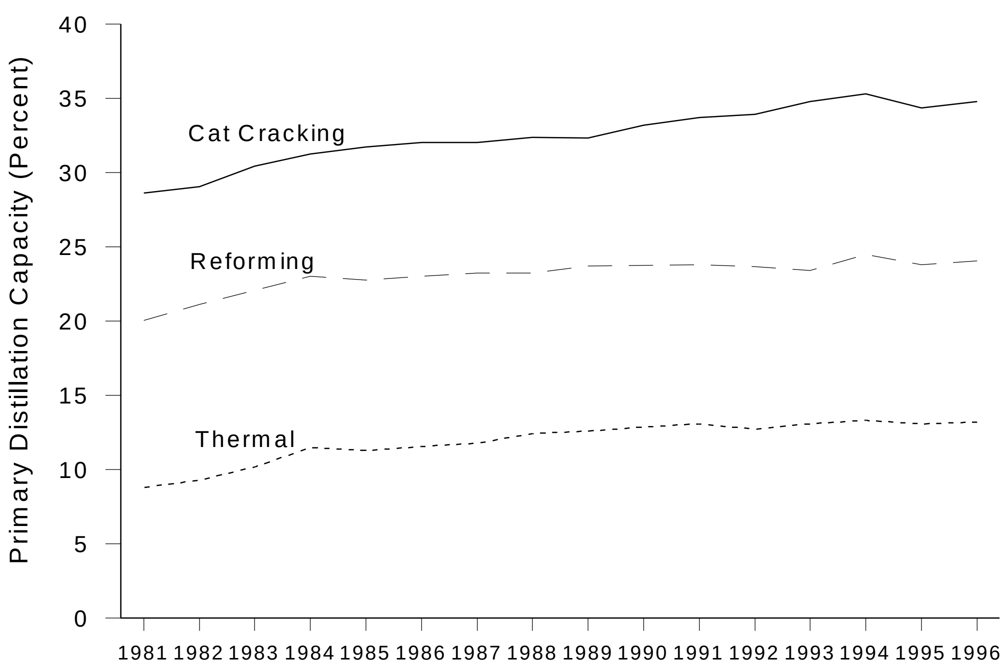
Before showing the full margin impact of similar refineries processing light versus heavy crude oils, the link between the light-heavy differential and average refinery margins can be explored by observing the simple spread between gasoline prices and light and heavy crude prices. Due to gasoline's strong influence over cash margins, the gasoline price spread should provide an indication of margin performance. Both the full margin and gasoline spread observations will illustrate the small premiums received by those processing heavier crude oils. Figure 97 shows the difference between gasoline price and two crude oil prices, one light and one heavy. The price spread is lowest for the highest valued, light, sweet crude oil (Bonny Light), and is highest for the lower valued, heavy, sour crude oil (Arab Heavy). Markets weakened in 1992 when world crude oil supply outstripped petroleum demand, and both gasoline price spreads fell, but the heavier crude spread fell more than the lighter crude spread. As the 1990's progressed, the supply of light, sweet crude oils in the Atlantic Basin increased, and the heavy crude oil-gasoline price spread fell closer to the light crude oil-gasoline price spread. In 1995, the Arab Heavy spread was almost at parity with the Bonny Light gasoline price

Figure 94. Decline in Heavy Fuel Oil Consumption
(Percent of Total Petroleum Products Consumed in Each Country or Region)



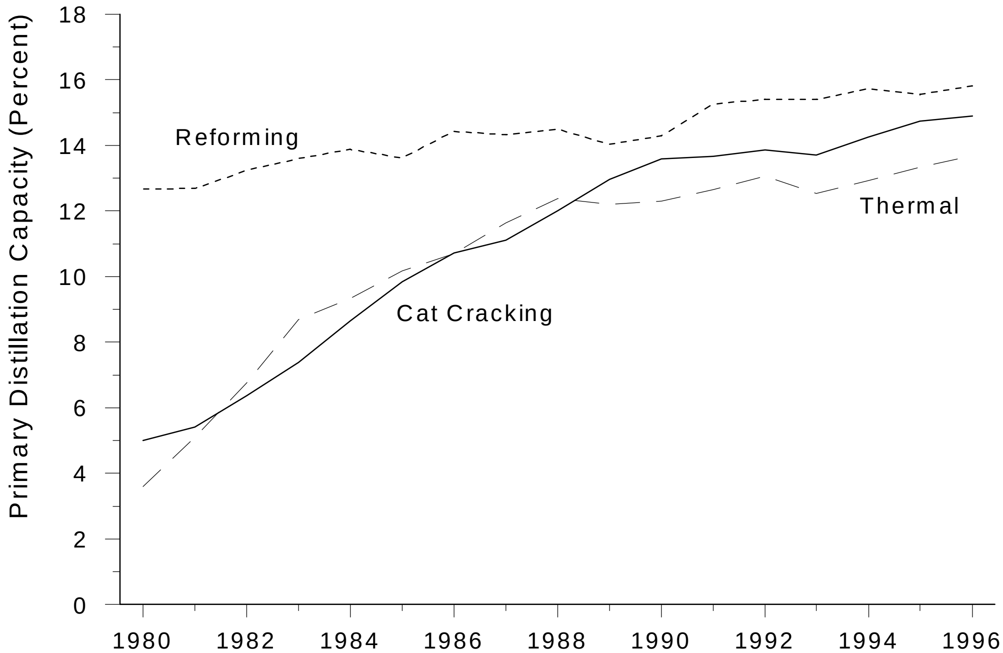
Source: British Petroleum, *Statistical Review of World Energy, 1996*.

Figure 95. U.S. Downstream Processing Capacity



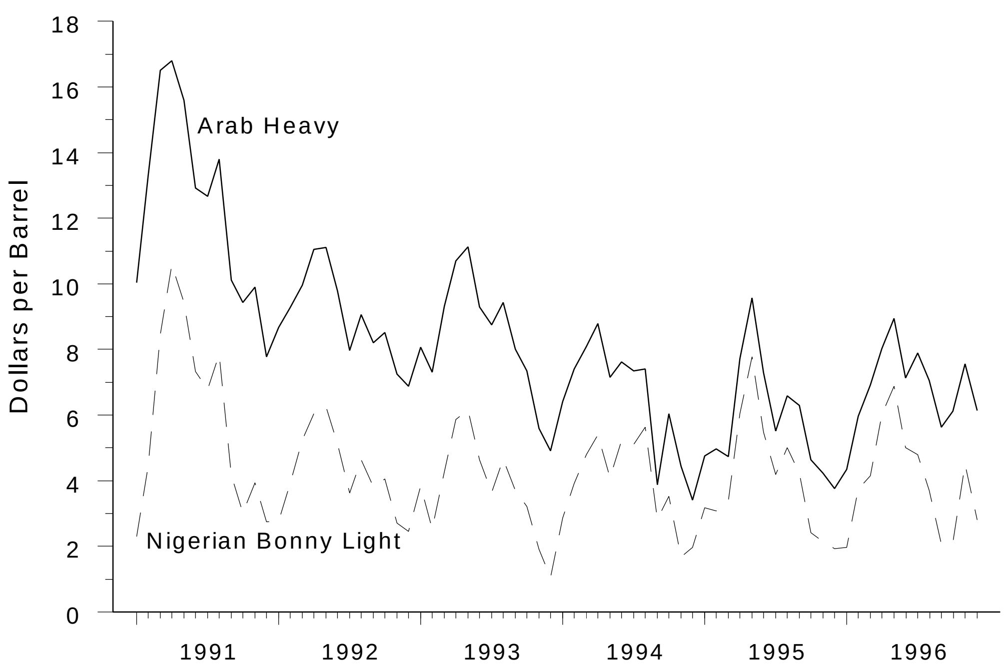
Sources: **1981-1995:** Energy Information Administration (EIA), Form EIA-820 "Annual Refinery Report." **1995:** The stream day capacities are projected capacities reported on Form EIA-820 "Annual Refinery Report" (1995)." **1996:** Number of refineries and crude distillation capacity from Form EIA-810 "Monthly Refinery Report" (January 1996).

Figure 96. Western European Downstream Processing Capacity



Source: Energy Information Administration (EIA). **Calendar Day Capacity as of January 1 of Each Year:** EIA, *International Energy Annual* (various issues), Table 3.6.

Figure 97. Gasoline Spread Comparisons
(Spot Gulf Regular Conventional - Spot Crude)



Source: Standard & Poor's Platts.

spread. Because of gasoline's strong effect on refining margins, one might expect to find that, as light-heavy crude differentials decline, the less complex refiners running light-sweet crude oils would see little change in margins, but more complex refiners running heavy-sour crudes would experience a decline. Hence, average industry margins would decline.

Now consider the full margin variation seen over the past decade as a result of light/heavy crude and product market variations. Two cases are used to explore the impacts. The first case compares two similar refineries processing different crude oils, one light and one heavy. This case illustrates the advantage to refiners of investing so as to be able to use lower priced, heavier crude oils without much change in product slate. The second illustration compares two refineries processing the same crude oil to produce different product slates, thus showing the advantage gained by investing to produce a lighter product slate.

The first case (Figure 98) compares the margins for Arab Light and West Texas Intermediate (WTI) crude oils processed in a cracking and coking refinery on the Gulf Coast. The figure shows the difference between the two margins. While both of these crude oils are being run through similar refineries, the Arab Light crude oil has a higher percent of heavy residual boiling range material than WTI, and therefore requires a substantially larger coking unit and also added hydrotreating to remove sulfur from the fluid catalytic cracking unit feedstock. The extra investment in equipment needed to process Arab Light requires a higher margin to make that investment economically viable. However, in 1986 and 1987, and again in 1994 and 1995, the margins for processing Arab Light in the more expensive refinery were smaller than those for processing WTI in the same refinery. From 1986 to 1990, Arab Light margins increased relative to WTI because the light-heavy crude price difference grew, providing increased contributions to the upgrading investment. But then the Arab Light margins declined relative to WTI until 1995, as the light-heavy crude oil price differences narrowed again. Over the last decade, refiners serving the same markets but using heavier crude oils have not earned a significant premium over refiners with less capital invested and using lighter crude oils.

The second case, which shows the historical advantage to refiners of investing to produce a lighter product slate, looks at two refineries producing different product slates from the same crude oil. A comparison of the margins for processing Brent crude oil in a Gulf Coast refinery with a coker and in an East Coast refinery containing no coking unit shows some of the benefits of upgrading to achieve a higher mix of lighter, higher-valued products (Figure 99). Although refinery upgrading is normally discussed in conjunction with heavy, sour crude oils, lighter crude oils also contain residual boiling materials that can be upgraded to lighter, higher valued products. This type of investment is driven only by light-heavy product price differentials; however, as discussed above, light-heavy product price differences are intimately tied to light-heavy crude price differentials. From 1986 to 1990, the Brent coking refinery earns an increasing margin premium over the non-coking refinery. However, the coking refinery's premium falls from 1990 to 1995. This difference also is affected by other factors such as regional product price differences, but the influence of the rise and fall in light-heavy crude oil and light-heavy product price differences is clearly evident.

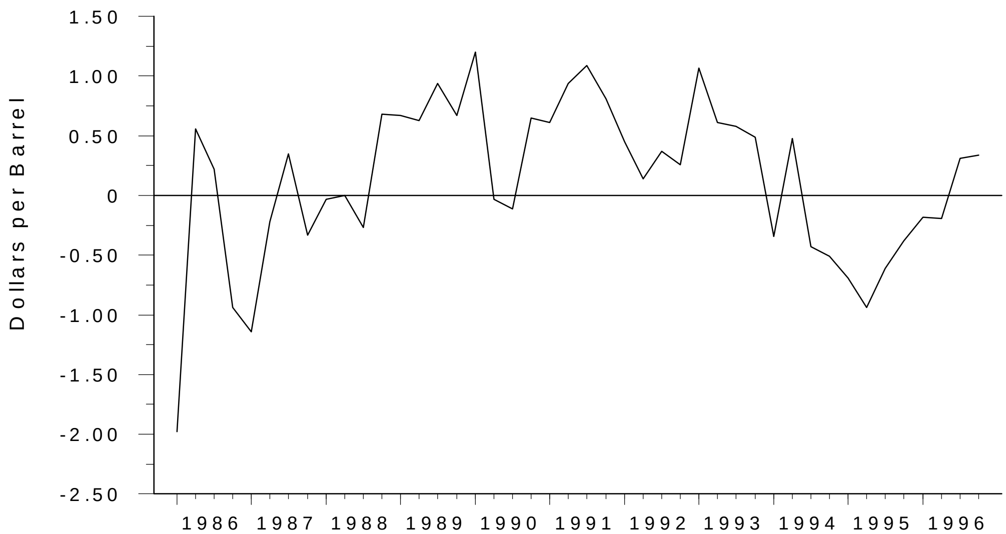
In summary, the market dynamics surrounding the interactions of light versus heavy product demand, light versus heavy crude availability, and availability of conversion capacity all contributed to the long-term margin variations over the past decade. These market dynamics affected not only those refiners who installed heavy material conversion capacity, but all refiners in the industry.

Refining Capacity Utilization's Influence on Margins Not Always Evident

Apart from product and crude prices, refinery capacity utilization is another variable that potentially can affect margin behavior as discussed above. In the United States, capacity utilization has increased significantly, averaging well over 90 percent since 1992, for the atmospheric distillation units. Utilization also increased for conversion units downstream of the distillations units, such as cokers and catalytic cracking units.[89] Generally, as production levels in any manufacturing industry approach capacity limits, marginal costs to produce a product increase. For example, idle capacity with high variable costs may be brought online to help meet rising demand. As marginal costs per unit of product increase, prices increase, and the manufacturing industry can experience an increase in average margin (price minus cost). In refining, costs per unit of product may increase at high utilization because downstream units can be fully loaded before distillation inputs reach maximum levels. (At this point, the refiner is getting hydroskimming yields on the last increments of capacity.) But refiners don't suddenly hit a capacity constraint. They have flexibility to avoid constraint-driven fast cost increases at high utilizations by changing operations, by using lighter crude oil mixes that don't require as much downstream unit capacity, and by purchasing product from other world refining areas. As a result, the importance of utilization only becomes apparent when refiners push to the last few increments of capacity, and then the results can be dramatic. California has

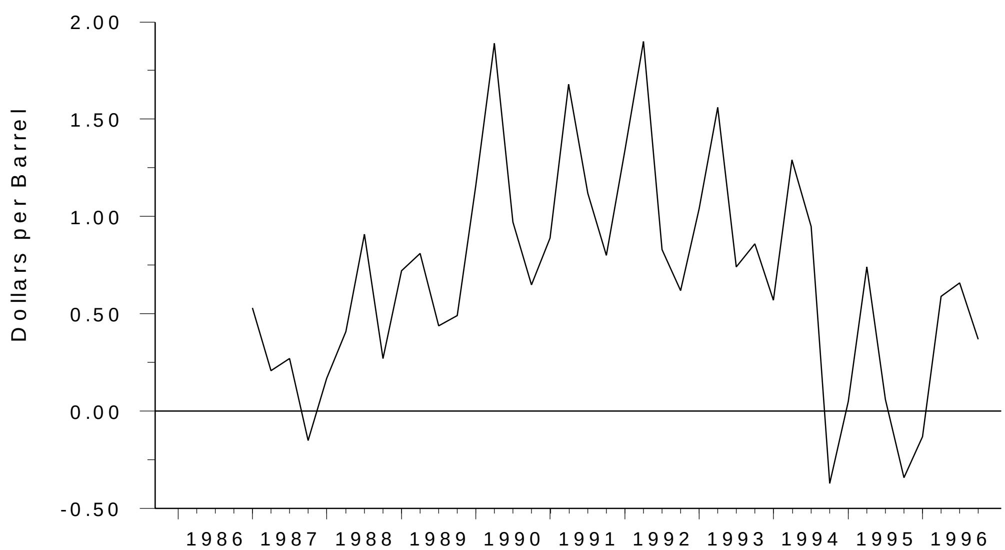
[89] Lidderdale, Tancred, Nancy Masterson, Nicholas Dazzo, "U.S. Refining Capacity Utilization," Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109 (95/10) (October 1995), pp. xxxiii-xxxix.

Figure 98. Value of Upgrading: Heavy Crude Margin - Light Crude Margin
(Arab Light (Heavy) and WTI (Light) Crude Processed in Complex Refinery)



Sources: **Crude Oil, Natural Gas Liquid, and Product Prices:** Standard & Poor's Platts. **Spot MTBE Price**: *Oxy-Fuel News*, Hart/IRI Fuels Information Services (Arlington, VA). **Crude Oil Transportation Costs**: Average spot freight rates reported in *Weekly Petroleum Argus*, Petroleum Argus Limited (New York, NY), *International Crude Oil and Product Prices*, Middle East Petroleum and Economic Publications (Nicosia, Cyprus) and *Oil and Energy Trends*, Blackwell Publishers (Oxford, UK). **Refinery Yields:** EIA estimates based on crude assays from company sources and downstream process unit yields based on proprietary correlations. **Operating Costs:** EIA estimates based on company data and various public literature sources. **Cost Escalation:** Based on Nelson Farrar Index published in first issue of each month of *Oil and Gas Journal*, Pennwell Publishing Co. (Tulsa, OK). **Purchased Natural Gas Price:** Energy Information Administration (EIA), price delivered to industrial customers in Louisiana and Texas, *Natural Gas Annual*. **Electric Power Cost:** EIA, large industrial customer price, *Electric Power Annual*.

Figure 99. Value of Upgrading: Margin with Coker Minus Margin Without Coker



Sources: **Crude Oil, Natural Gas Liquid, and Product Prices:** Standard & Poor's Platts. **Spot MTBE Price**: *Oxy-Fuel News*, Hart/IRI Fuels Information Services (Arlington, VA). **Crude Oil Transportation Costs**: Average spot freight rates reported in *Weekly Petroleum Argus*, Petroleum Argus Limited (New York, NY), *International Crude Oil and Product Prices*, Middle East Petroleum and Economic Publications (Nicosia, Cyprus) and *Oil and Energy Trends*, Blackwell Publishers (Oxford, UK). **Refinery Yields:** EIA estimates based on crude assays from company sources and downstream process unit yields based on proprietary correlations. **Operating Costs:** EIA estimates based on company data and various public literature sources. **Cost Escalation:** Based on Nelson Farrar Index published in first issue of each month of *Oil and Gas Journal*, Pennwell Publishing Co. (Tulsa, OK). **Purchased Natural Gas Price:** Energy Information Administration (EIA), price delivered to industrial customers in Louisiana and Texas, *Natural Gas Annual*. **Electric Power Cost:** EIA, large industrial customer price, *Electric Power Annual*.

experienced this problem with the introduction of its unique RFG that few other refiners outside of the area can produce in large quantities.

With the exception of California, the U.S. refining industry has not exhibited increases in margin with corresponding increases in capacity utilization. While distillation capacity utilization and capacity utilization for downstream units grew strongly throughout the 1990's, margins declined (Figure 100). From an economic viewpoint, this observation implies the industry is not hitting capacity constraints where the downstream units are fully loaded, or at least any effects of capacity utilization are relatively small and masked by other, more dominant margin drivers.

In recent years, analysts have begun to focus on the utilization of downstream capacity, which represents a far larger investment per barrel than distillation capacity, to explain margin behavior. Demand increased and distillation capacity utilization increased in the 1990's, and downstream units were added and improved to be able to increase production of light products and to respond to changing environmental regulations. The underlying cost structure of the industry changed. While more expensive units were being expanded, efficiencies were also being incorporated. This change resulted in debottlenecking and, in some cases, improvements in variable costs. But here again, it has proven difficult to establish a good quantitative relationship between capacity utilization and margins. Regardless, we cannot conclude from lack of a simple correlation that capacity utilization is not an important variable. In the future it could have a significant impact on margins.

A better understanding of the capacity utilization/margin relationship can be gained by reviewing how refiners operate residual conversion facilities. Once refiners install cokers or heavy oil crackers, they tend to operate these units near full capacity, seemingly without regard to crude or product price variation. But full utilization is generally a rational economic decision. Most of the cost of the facilities are fixed costs, such as the sunk investment cost and labor used to run and maintain the units. Fuel, utilities, catalysts and chemical costs are functions of throughput. Thus, based on variable costs, the refiner may find it more economic to buy heavier crude oils and run the conversion units at full utilization most of the time, even though the difference between light and heavy crude prices may have contracted significantly. The smaller price differences diminish the ability of the refiner to recoup the investment in the conversion equipment and earn a competitive return. The result is that downstream units may be run at high utilizations both when margins are rising and when they are falling.

The measures of the need for more or less bottoms conversion capacity are the light-heavy crude and product price differentials. There is no fixed demand volume for residual fuel oil, and when bottom conversion capacity is short and light crude availability is tight, residual fuel production is large. To clear the market, residual fuel producers must drop the price and sell into less attractive markets. The economics during such situations favor installing more conversion equipment to reduce residual fuel production. But if too many refiners install conversion equipment, or the quality balance of available supply changes, prices will shift. In all these cases, capacity utilization will not indicate if a capacity surplus exists or more is needed, but the light-heavy price differences are clear indicators.

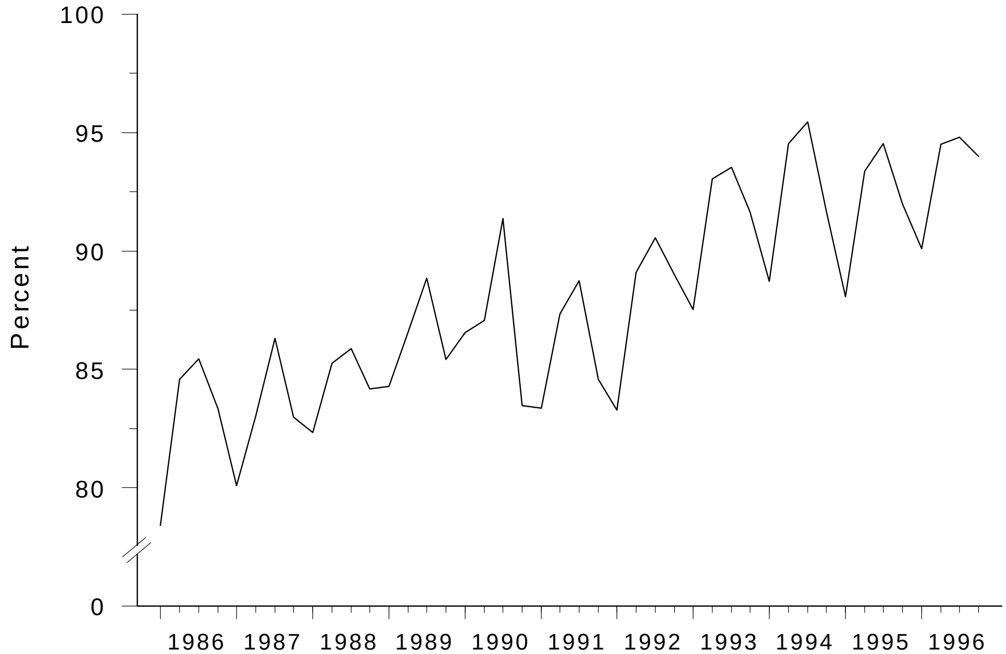
U.S. refinery utilization must also be viewed in the context of world refining capacity. In the future, even if U.S. refineries begin to feel capacity constraints, other countries may be able to produce products in excess of their own needs and ship them to the United States more cheaply than U.S. refiners can produce the products. In this case, the U.S. will not see much of an increase in operating costs until world industry excess capacity diminishes.

Eventually, world petroleum demand likely will grow until capacity bottlenecks are experienced. If the industry reaches a point where the most expensive downstream units are fully loaded, refiners will begin using more light crude oils that do not require as much downstream capacity to produce the higher valued products if light crude oil supplies are available. The increase in light crude oil demand will, in turn, drive up the light crude oil price relative to heavy crude oil and the light product prices relative to heavy products. Margins would be expected to increase as well. That increase in margins will provide the incentive to build new capacity.

Reformulated Gasoline Margin Impacts Were Overwhelmed By Other Factors

One of the most significant regulatory factors affecting refining costs was the implementation of the Clean Air Act Amendments of 1990 (CAAA). Investments were made to lower the sulfur content of diesel fuel and to comply with the specifications of reformulated gasoline. Many of the refining facility improvements made during the 1990's were prompted by the need to meet the new clean fuel requirements. (The oxygenated gasoline requirement only required refiners to add oxygenates to the gasoline and adjust how some units were run in order to correct for the additional octane provided by the oxygenates.)

Figure 100. Atmospheric Distillation Unit Capacity Utilization



Sources: **Distillation Capacity:** Energy Information Administration (EIA), 1981-1995—*Petroleum Supply Annual* (Vol. 1), Table 16. 1996—*Petroleum Supply Monthly* (February 1997), Table 28.

EIA previously analyzed the effect of RFG on refiners and reported the results in the *Petroleum Marketing Monthly*.[90] The result of the current analysis is similar to the earlier EIA study in that the margins are based on specific crude oils used in specific U.S. regions. Yield and cost data pre-RFG and post-RFG introduction were developed, which allowed for separation of RFG cost impacts from market changes that occurred simultaneously.

Not all refiners were equally affected by the regulatory change. Bonny Light crude oil was considered a very good crude oil for producing gasoline in the pre-RFG era. It contains high yields of good quality naphtha, which is reformed to produce gasoline. Unfortunately, the naphtha derived from many light crude oils also contains relatively high levels of benzene and material that yields benzene when the naphtha is processed. While benzene has a high octane value, it is also carcinogenic and RFG specifications limit its level in gasoline. In order to meet RFG specifications, refiners historically using only Bonny Light or Brent had to invest in new processes such as isomerization to remove benzene from the naphtha or to separate some of the naphtha containing benzene for sale as naphtha product. Arab Light crude oil, on the other hand, benefits from the RFG oxygen requirement. Arab Light naphtha has a low aromatic content, including low benzene content, so benzene removal is less problematic than with Bonny Light. However, Arab Light's low aromatic content results in a relatively poor octane gasoline pool. Fortunately, the oxygenates required in RFG not only improve fuel cleanliness, but also boost octane, countering the lack of aromatics. WTI sits in the middle between Bonny Light or Brent and Arab Light.

A close examination reveals that the change in refining costs attributable to RFG had no major impact on margin behavior between 1993 and 1995. In fact other market factors overwhelmed any impact of the introduction of RFG. For example, Arab Light margins fell much more between 1993 and 1995 than either Bonny Light or WTI, in spite of its RFG benefit (Figure 98). The rapidly declining light-heavy crude difference had more influence over the relative margin changes than did RFG. When gasoline margin contributions were broken out separately, Arab Light crude processors showed slightly higher contributions to margins from this product, as expected, but this advantage is overwhelmed by factors affecting costs. As stated in the earlier study, across the spectrum of refineries, very little additional margin appears to have been generated to cover the increased

[90] John Zyren, Charles Dale, and Charles Riner, "1995 Reformulated Gasoline Market Affected Refiners Differently," Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380(96/01) (January 1996), pp. xiii-xxxi.

facility investment or any return on RFG investment in the time since RFG production began through 1996.

Gulf Coast Margins Have Been Generally Higher Than Those on the East Coast

The last factor contributing to margin variation is the regional differences in refineries. This chapter explores only East Coast and Gulf Coast refineries, leaving the unique aspects of California refineries for a future discussion. Table 16 shows the margins calculated for typical refineries in each area using several crude oils.

Figure 101 compares the margins for the East Coast refinery running Brent crude oil and the Gulf Coast refinery running Brent and WTI. The Gulf Coast refinery margins are generally higher than the East Coast margins. The extra conversion equipment contained in the Gulf Coast refinery allowed the refiner to improve the yields of the lighter, higher valued products over the East Coast refiner, even when using lighter crude oils. Yet the interesting point is that the improvement is fairly small. Very little premium is available to cover the costs and returns on this extra conversion equipment. However, the East Coast refinery used to generate these margins is as cost efficient as the Gulf Coast refinery for the same processing equipment. In reality, some East Coast refineries are not very cost efficient, so Gulf Coast refiners likely experienced larger margin premiums over East Coast refiners than shown here.

Seasonal variations are slightly different between the Gulf Coast and the East Coast refineries. The Gulf Coast refineries exhibit large second quarter margins, which fall again in the third quarter. Up until 1992, the East Coast refinery margins were similar. However, beginning in 1992, a slightly different pattern began emerging. While East Coast margins rise in the second quarter, they don’t fall back as much in the third quarter as they do on the Gulf Coast margins. The reasons for this shift are not clear.

Since 1990, the margins of Gulf Coast refiners processing either Brent crude oil or WTI moved together fairly closely, with East Coast refiners using Brent trailing somewhat behind. Since 1994, though, the East Coast refiners using Brent improved their position. Part of this shift may be due to a shift in relative gasoline spot prices between the East and Gulf Coasts that occurred during 1994 and 1995. Since 1990, New York Harbor spot gasoline prices frequently exhibited a stronger premium over Gulf Coast prices during the second half of the year. But in 1994 and 1995, this premium was much larger than usual, boosting the margin for East Coast refiners using lighter crude oils.

Spring 1996 and Future Trends

As was discussed in Chapter 1, gasoline and distillate prices rose rapidly in April of 1996. Were these price increases reflected in unusually high margins? As shown in Figure 88 and other margin figures throughout this chapter, the answer is no. The first and second quarter margins in 1996 were not unusually high compared to those experienced over the last decade.

Two factors contributed to cash margin increases since 1994. The first was a mild widening of the light-heavy price differences for both crude and product. While this increase was not very significant, it reversed the decline in this price difference. As discussed above, the turnaround in light-heavy price differences should have a positive effect on margins. The second factor that caused stronger margin performance was a tight petroleum supply/demand balance. In 1996, this latter factor probably had a greater influence on margin increases.

Recall from earlier discussion in this chapter that from 1992 through 1993 markets weakened:

- petroleum production exceeded petroleum demand worldwide as well as in the United States;
- worldwide stock builds in the second and third quarters exceeded stock draws in the high demand fourth and first winter quarters;
- market prices for crude oil and products weakened;
- seasonal product price spread increases were smaller than usual; and
- overall price levels drifted downward, causing lackluster margin performance.

The supply/demand balance began to tighten in 1994, but record low light-heavy price differences kept margins depressed. In 1995 and 1996, the supply/demand balance pattern is the reverse of 1992 and 1993:

- product demand outpaced crude supply increases;
- winter stock draw downs exceeded summer stock builds, causing overall inventory levels to drop;
- this tight balance caused crude prices to increase; and
- in the summer quarters (second and third), U.S. refiners’ margins benefitted from the tight supply/demand balance reflected in low inventories.

The margins for the second quarter 1996 were similar to those second quarter 1995, and both second quarter margins showed stronger seasonal upturns than were experienced in 1992 and 1993. If the light-heavy price differences had also been high, the overall margin levels would have been higher.

Table 16. Quarterly Margins

Refinery	85Q1	Q2	Q3	Q4	86Q1	Q2	Q3	Q4	87Q1	Q2	Q3	Q4	88Q1	Q2	Q3	Q4	89Q1	Q2	Q3	Q4
BONNY LT -EC					1.33	2.99	1.09	0.53	0.14	0.68	0.33	1.25	1.18	2.26	2.76	4.02	1.45	3.15	2.38	2.24
BRENT-EC									-0.20	0.48	0.13	0.58	0.66	1.95	2.28	3.71	1.28	3.72	2.06	1.54
BRENT-GC									0.33	0.69	0.40	0.43	0.83	2.36	3.20	3.98	2.00	4.53	2.50	2.03
WTI-GC	1.13	2.33	1.23	0.65	2.23	2.70	0.61	0.28	0.20	0.25	-0.50	0.21	0.30	1.69	3.17	3.39	1.38	3.19	1.21	1.66
ARAB LT-GC	-2.34	-0.08	-1.17	-0.48	0.25	3.26	0.84	-0.67	-0.95	0.03	-0.15	-0.12	0.27	1.69	2.90	4.07	2.05	3.83	2.15	2.33

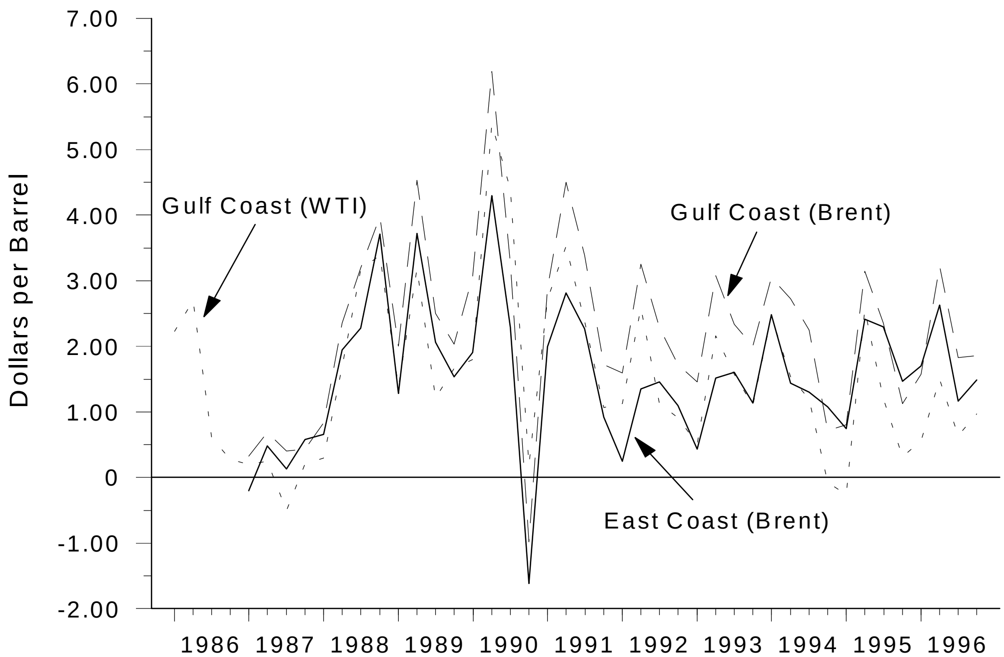
Refinery	90Q1	Q2	Q3	Q4	91Q1	Q2	Q3	Q4	92Q1	Q2	Q3	Q4	93Q1	Q2	Q3	Q4	94Q1	Q2	Q3	Q4
BONNY LT -EC	1.96	4.56	3.47	-1.41	1.42	3.32	2.66	1.05	0.62	1.69	1.72	1.06	0.62	1.63	1.73	1.40	2.60	2.10	1.97	0.37
BRENT-EC	1.91	4.30	2.29	-1.62	1.99	2.81	2.27	0.92	0.25	1.35	1.46	1.10	0.43	1.52	1.60	1.14	2.48	1.44	1.30	1.08
BRENT-GC	3.07	6.19	3.26	-0.98	2.88	4.50	3.39	1.72	1.59	3.25	2.29	1.72	1.46	3.08	2.34	2.00	3.05	2.73	2.25	0.72
WTI-GC	1.80	5.39	4.40	0.19	2.72	3.53	2.38	1.07	1.13	2.59	1.13	0.91	0.51	2.16	1.57	1.10	2.46	1.54	1.19	-0.07
ARAB LT-GC	3.01	5.36	4.29	0.84	3.33	4.46	3.47	1.88	1.58	2.73	1.50	1.17	1.58	2.77	2.16	1.59	2.12	2.02	0.76	-0.58

Refinery	95Q1	Q2	Q3	Q4	96Q1	Q2	Q3	Q4
BONNY LT -EC	0.05	1.83	2.08	1.23	1.01	1.96	1.17	1.08
BRENT-EC	0.75	2.41	2.30	1.47	1.70	2.63	1.17	1.49
BRENT-GC	0.80	3.15	2.36	1.13	1.57	3.22	1.83	1.86
WTI-GC	-0.26	2.56	1.20	0.32	0.56	1.50	0.64	0.97
ARAB LT-GC	-0.96	1.62	0.58	-0.06	0.38	1.31	0.95	1.31

Note: EC=East Coast Refinery. GC=Gulf Coast Refinery.

Sources: **Crude Oil, Natural Gas Liquid, and Product Prices:** Standard & Poor's Platts. **Spot MTBE Price**: *Oxy-Fuel News*, Hart/IRI Fuels Information Services (Arlington, VA). **Crude Oil Transportation Costs**: Average spot freight rates reported in *Weekly Petroleum Argus*, Petroleum Argus Limited (New York, NY), *International Crude Oil and Product Prices*, Middle East Petroleum and Economic Publications (Nicosia, Cyprus) and *Oil and Energy Trends*, Blackwell Publishers (Oxford, UK). **Refinery Yields:** EIA estimates based on crude assays from company sources and downstream process unit yields based on proprietary correlations. **Operating Costs:** EIA estimates based on company data and various public literature sources. **Cost Escalation:** Based on Nelson Farrar Index published in first issue of each month of *Oil and Gas Journal*, Pennwell Publishing Co. (Tulsa, OK). **Purchased Natural Gas Price:** Energy Information Administration (EIA), price delivered to industrial customers in Louisiana and Texas, *Natural Gas Annual*. **Electric Power Cost:** EIA, large industrial customer price, *Electric Power Annual*.

Figure 101. East Versus Gulf Coast Margins Running Brent and WTI
(Based on Spot Product Prices)



Sources: **Crude Oil, Natural Gas Liquid, and Product Prices:** Standard & Poor's Platts. **Spot MTBE Price**: *Oxy-Fuel News*, Hart/IRI Fuels Information Services (Arlington, VA). **Crude Oil Transportation Costs**: Average spot freight rates reported in *Weekly Petroleum Argus*, Petroleum Argus Limited (New York, NY), *International Crude Oil and Product Prices*, Middle East Petroleum and Economic Publications (Nicosia, Cyprus) and *Oil and Energy Trends*, Blackwell Publishers (Oxford, UK). **Refinery Yields:** EIA estimates based on crude assays from company sources and downstream process unit yields based on proprietary correlations. **Operating Costs:** EIA estimates based on company data and various public literature sources. **Cost Escalation:** Based on Nelson Farrar Index published in first issue of each month of *Oil and Gas Journal*, Pennwell Publishing Co. (Tulsa, OK). **Purchased Natural Gas Price:** Energy Information Administration (EIA), price delivered to industrial customers in Louisiana and Texas, *Natural Gas Annual*. **Electric Power Cost:** EIA, large industrial customer price, *Electric Power Annual*.

What does the future hold? The turnaround in light-heavy price differences indicates increasing margin strength. But the light-heavy differentials are widening slowly, and by the end of 1996, the associated margin changes were small. Supply/demand balances will again move into a supply surplus following typical economic cycles, but such movements do not happen quickly. The roots of the surplus lie in increased Iraqi production, increasing non-OPEC production in the North Sea and Latin America, and any decline in OPEC discipline to maintain production quotas and refrain from overproduction. These changes happen over many months. The tight supply/demand balance will not reverse in time to significantly affect margin performance in 1997. However, the balance is expected to begin changing in 1998. The promises of increased light sweet crude oil production in the North Sea and in Colombia will continue to keep light-heavy differentials low, dampening margin growth. Thus, 1997 may not see significant improvement in refinery margins, even if the supply/demand balance remains relatively tight all year.

8. Financial Performance: Low Profitability in U.S. Refining and Marketing

The profitability of U.S. refining and marketing has been volatile. In the past 10 years or so, the rate of return to the major petroleum companies' U.S. refining and marketing assets ranged from the most profitable of their lines of business to near zero. In the 1990s, the profitability of U.S. refining and marketing was frequently lower than that of U.S. industry generally. The following chapter reviews the factors underlying the volatility of U.S. refining and marketing profitability and the sources of depressed rates of return in the 1990s. The chapter concludes with an examination of refining profits in the context of the rises in gasoline and distillate prices in the first half of 1996.

An industry's standing in the capital markets largely depends on its profit prospects and the perceived risks associated with them. Nevertheless, analysis of past profit performance of an industry can yield insights as to fundamental sources of profitability and the consequent course of investment. The profitability of the U.S. refining industry over the past 10 years or so has been volatile and, in the 1990's, frequently lower than U.S. industry generally. In order to understand this volatility and to assess the prospects for this industry, this chapter reviews the sources of U.S. refining profitability.

The analysis utilizes information reported annually to the Energy Information Administration's (EIA's) Financial Reporting System (FRS) by the two dozen or so U.S.-based major energy-producing companies.[91] The FRS contains financial data and associated measures of energy-related operations by line of business, including U.S. refining/ marketing. Over the past ten years, the FRS companies accounted for 72 percent of U.S. refinery capacity. The FRS data are complemented by financial information drawn from annual reports for non-major domestic refiners.

Margins, Operating Costs, and Profitability

More often than not, petroleum industry profitability has been lower than the profitability of overall U.S. industry. Figure 102 shows the return on equity (net income as a percent of stockholders' equity), an often-used measure of corporate profitability, for petroleum companies and the Standard and Poor's (S&P) group of 400 of the largest U.S. industrial corporations (excluding energy companies). The petroleum companies include the majors (as represented by the FRS companies), publicly-traded independent oil and gas producers, and publicly-traded refiners other than the majors. For most of the past 10 years, petroleum company profitability has not kept pace with that of other large industrial corporations. In 1995, independent refiners and oil and gas producers registered very poor financial performances. But the FRS majors registered an uptick in overall profitability, largely due to an upswing in chemical profits. Also, over the past 10 years, the FRS companies' U.S. refining and marketing profitability has been below the overall profitability of their other businesses, except for 1988 and 1989 (Figure 103). However, in the first six months of 1996, all segments of the petroleum industry made noticeable gains in profitability.

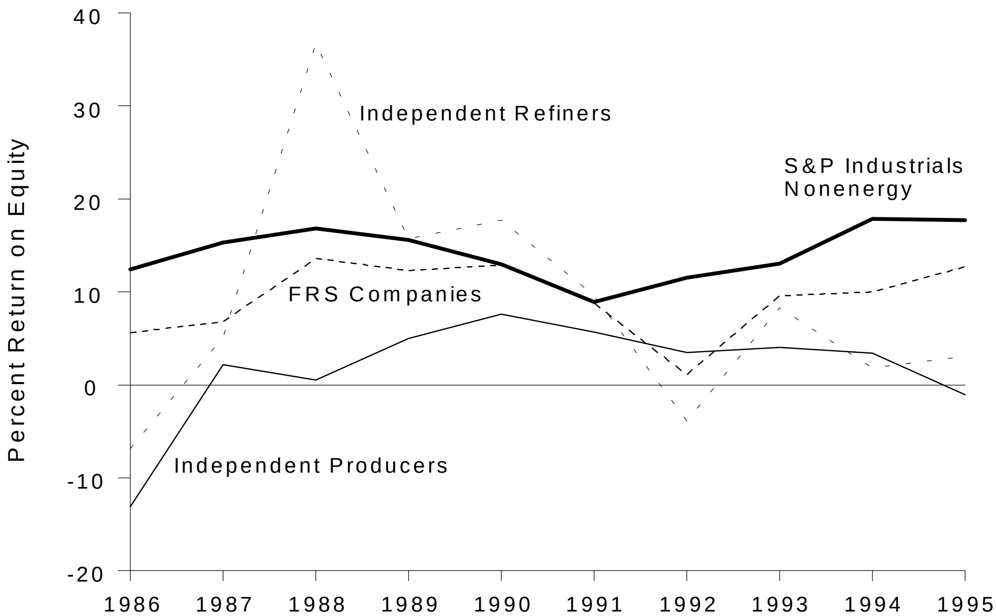
Income from refining operations primarily depends on the spread between refined product prices and raw material input prices (termed, the gross refining margin), operating costs, and volumes processed and sold. The gross refining margin is an important determinant of short-term refining profitability. For example, an examination of the gross refining margin reveals the sources of increased U.S. refining profits in the context of the gasoline price runup in the First Half of 1996 (see the section "Petroleum Price Rises Yield Profit Gains in First Half of 1996").

In the longer term, though, the relationship between refining profitability and the gross refining margin attenuates. For example, the correlation between the FRS companies' annual U.S. refining/marketing profitability and a somewhat broader definition of the gross refining margin[92] is not significant by

[91]For a detailed description of the FRS and analyses of financial issues and trends among U.S. based major energy companies, see Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206 (Washington, DC, January 1997).

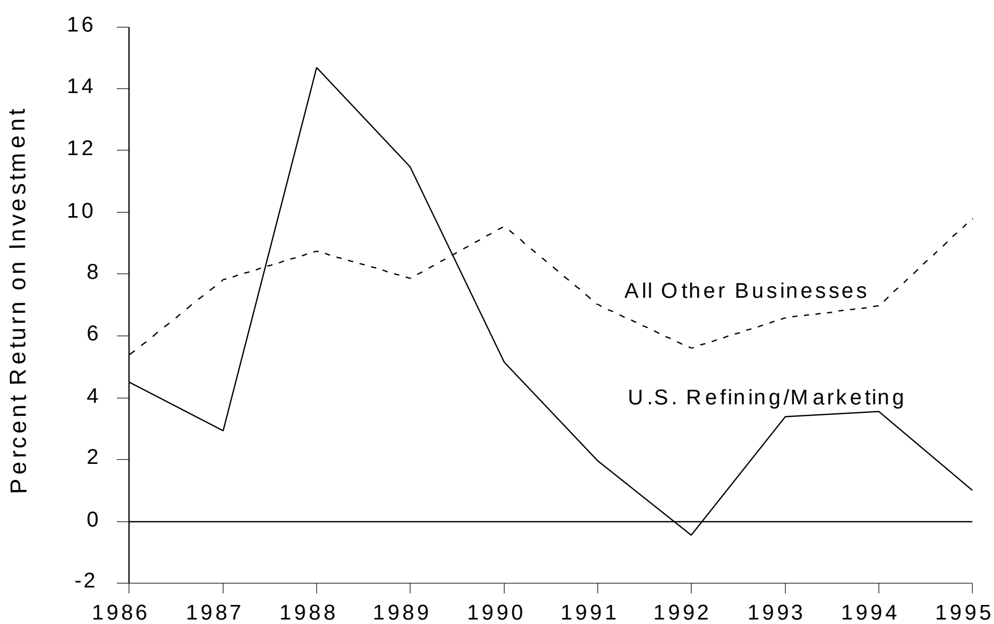
[92]Return on investment was measured as contribution to net income/net investment in place. The FRS gross refined product margin consists of refined product revenues less raw material and product purchases divided by refined product sales volume.

Figure 102. Annual Return on Equity for Petroleum Companies and U.S. Industry



Return on Equity = Net income as a percent of shareholders equity.
Source: Standard & Poor's Compustat and fourth quarter press releases.

Figure 103. FRS Companies' Return on Investment in U.S. Refining/Marketing and All Other Lines of Business



Return on Investment = Net income divided by net investment in place.
Source: Energy Information Administration (EIA), Form EIA-28.

the usual statistical conventions.[93] The reason for this weak relationship is that the gross margin excludes operating costs such as refinery energy expense and maintenance of marketing networks. Operating costs may not typically vary much from quarter to quarter, but in a longer term context they are a key component of profit change. Of particular importance is the strong relationship between U.S. refining/marketing profitability and the net refining margin based on FRS data (i.e., the gross margin less out-of-pocket operating costs) (Figure 104).[94] Thus, examination of the components of the net refining margin should provide insights as to the level and volatility of U.S. refining profitability. Table 17 presents the components of the net refining margin and measures of U.S. demand for the FRS companies' refined products, and refinery utilization for the peak and trough years of refining profitability.

The profitability story in the 1980's is largely told by the dynamics of demand, capacity rationalization, and reductions in operating costs, as gross margins were fairly stable over the period. Following full deregulation of petroleum prices in 1981, refining profitability in the United States reached its lowest point in 1984. The U.S. refining industry was plagued by a falloff in demand and massive amounts of excess crude oil distillation capacity. The net margin on the FRS companies' U.S. refining and marketing operations was only 1 penny per barrel in 1984. However, the gross margin changed little from the previous peak profitability year of 1979. What did change was demand (down 19 percent), capacity utilization (down 9 percentage points), and operating costs (up $1.80 ($1995) per barrel). Moving to the peak profitability year of 1988, most of the factors that devastated the bottom line in 1984 turned around: demand was up 17 percent, capacity utilization noticeably improved, and operating costs declined by more than $2 per barrel. Again, the gross margin changed little.

[93]The regression of the FRS U.S. refining/marketing return on investment (ROI) on the FRS gross margin (constant dollars) for 1977 to 1995 yielded the following results:

$$ROI = -0.068 + 0.737 \text{ (FRS Gross Margin)} \quad R^2 = 0.059.$$

The t-statistic for the coefficient of the FRS Gross Margin was 1.00, which is far below the conventional thresholds of statistical significance.

[94]To demonstrate the relationship between refining returns and the net refining margin, a regression was run using FRS U.S. refining/marketing return on investment (ROI) against the FRS net refined product margin (constant dollars) for the years 1977 to 1994.

The regression results for 1977-1995 were:

$$ROI = -1.3 + 6.2 \text{ (FRS Net Margin)} \quad R^2 = 0.852.$$

The regression produced a t-statistic of 9.90 for the independent variable, indicating that the probability of the above association between ROI and the FRS net margin occurring by chance is nearly nil.

The FRS companies' return on U.S. refining and marketing investment fell from its post-embargo peak in 1988 to zero in 1992. Demand for the FRS companies' refined products fell 7 percent over this period. Unlike the 1980's when gross margins held fairly steady, weak demand squeezed the spread between product prices and the prices of crude oil inputs. Overall operating costs also increased owing to a rise in marketing costs. The increase in marketing costs was widespread, with 16 of 18 FRS refiners reporting higher unit marketing costs between 1988 and 1992. The reasons for higher marketing costs are not altogether clear. Advertising outlays were up, reflecting a resurgence of growth in gasoline marketing in the wake of the oil price collapse of 1986. Also, the added costs of complying with leaking underground storage tank requirements were a contributing factor to higher marketing costs.

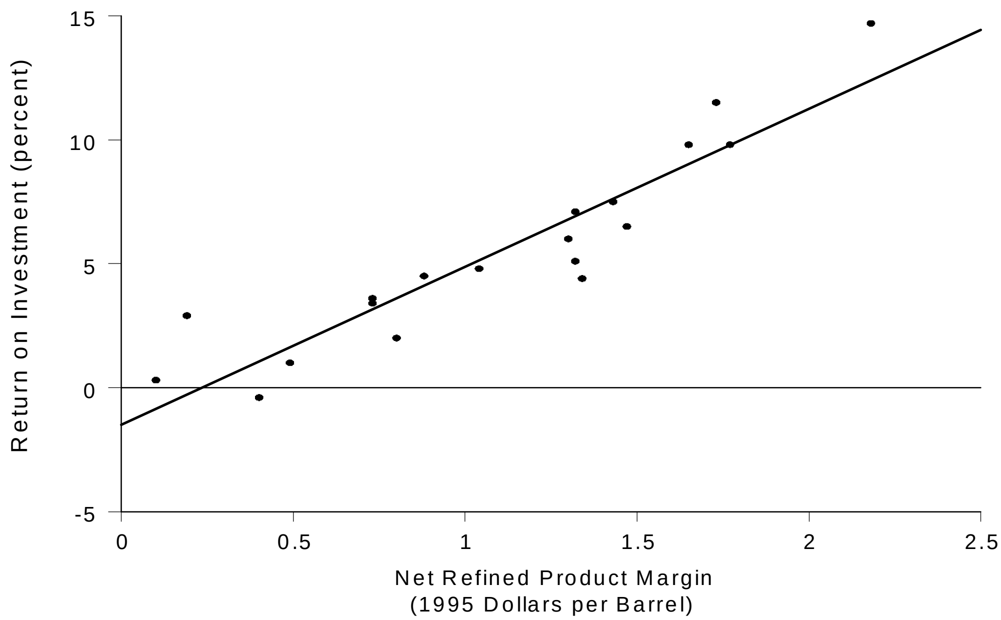
The profitability of the FRS companies' U.S. refining operations recovered slightly in 1993 and 1994, but remained low by historical standards (Figure 102). This recovery is remarkable since it occurred while the gross margin fell by nearly $1.30 per barrel. Growth in demand of about 2 percent helped the bottom line but most of the improvement in earnings came from operating cost reductions, mainly marketing costs. Nearly all of the FRS refiners reported lower marketing costs between 1992 and 1994, citing restructuring and efficiencies gained through greater retail outlet productivity. Also, the FRS companies reduced their advertising outlays, at least for television. On the refining side, cost cutting by the companies and higher capacity utilization contributed to improved profits.

In 1995, increases in refined product prices did not match the rise in crude oil costs. The consequent squeeze on margins was in part due to the effects of unusually warm winter weather on first-quarter heating fuel demand and to complications arising from the introduction of reformulated gasolines. As a result, the FRS companies reported a 1.0-percent return on their U.S. refining/marketing investment base, the third poorest financial performance in nearly two decades. Despite jumps in distillate and gasoline prices in 1996, U.S. refining operations fared only slightly better in terms of financial performance than they did in 1995. For example, major petroleum companies that separately disclosed quarterly financial results for their U.S. refining and marketing operations reported that income from these operations in 1996 was 15 percent above the comparable total in 1995.[95]

Examination of the FRS companies' U.S. refined product margins is thus seen to reveal the sources of volatility in

[95]Based on fourth quarter 1996 press releases. Data for 1996 to update most of the figures and tables in this chapter were not available at the time this report went to press.

Figure 104. U.S. Refining/Marketing Return on Investment and Refined Product Margins for FRS Companies, 1977-1995



Source: Energy Information Administration (EIA), Form EIA-28.

Table 17. U.S. Refined Product Margins and Costs per Barrel Sold for FRS Companies, Selected Years, 1979 - 1995
(1995 Dollars per Barrel)

	1979	1984	1988	1992	1994	1995
Gross Margin[a]	8.21	8.37	8.52	7.39	6.11	5.53
less						
Marketing Costs	1.95	2.63	1.96	2.90	1.85	1.75
Energy Costs	2.04	2.78	1.33	1.21	0.98	0.82
Other Operating Expense	2.57	2.95	3.02	2.88	2.56	2.47
equals						
Net Refined Product Margin[b]	1.63	0.01	2.22	0.41	0.72	0.49
Refined Product Sales (mbd)`	14,868	12,088	14,114	13,089	13,455	13,641
Refinery Capacity Utilization Rate (percent)	89	80	86	89	92	92

[a]Refined product revenues less raw material and product purchases divided by refined product sales volumes.
[b]Calculated from unrounded data.
Note: Years shown prior to 1994 are successive peak and trough years of U.S. refining/marketing profitability.
Source: Energy Information Administration (EIA), Form EIA-28.

rates of return to U.S. refining and marketing. The volatility of U.S. refining/marketing profitability over the past decade or so reflects a combination of swings both in the spread between refined product prices and crude oil input prices and in marketing costs, which, despite the massive restructuring of marketing networks, have shown a varying pattern over time with a tendency toward long-term decline only recently evident. Further, the low level of refining/marketing profitability in the 1990's is largely traceable to lower gross margins which were only partly offset by reductions in operating costs. However, there are other developments that have contributed importantly to the longer term course of U.S. refining/marketing profitability. These developments are not directly observable in the data on margins, but, instead, are best understood in the context of capital deployment.

Investment and Capital Intensity in U.S. Refining and Marketing

The capital intensity of a process generally refers to the amount of capital used to produce a unit of output from the process. Profitability and capital intensity are closely related. Simply put, if a process becomes more capital intensive, then unless there is an increase in profit per unit of output, profitability will decline.

In the 1990's, U.S. refining was hit by lower gross margins following the peak years of 1988 and 1989. Also, over the same period, the capital intensity[96] of U.S. refining increased by 50 percent or so after remaining nearly unchanged for several years (Figure 105). Together, these developments underlie the generally low rates of return to U.S. refining and marketing in the 1990's. Examination of investment patterns in U.S. refining proves useful for understanding why capital intensity rose in some periods and was unchanged in other periods.

The past 20 years saw several distinct phases of capital deployment in U.S. refining. Investment patterns during this span had the effect of increasing the capital intensity of these operations. Beginning in the late 1970's and continuing through the early 1980's, the FRS companies led U.S. refiners in making investments to upgrade their capability to utilize heavier, more sulfurous crude oils. The companies premised these investments on expectations that the composition of world supplies would shift toward lower quality, lower priced crude oils. Led by the FRS companies, many U.S. refiners invested in specialized plant and equipment in order to profit from the expected growth in the wedge in prices favoring lower quality crudes. Also, market adjustments made in the context of the crude oil price escalations of the 1974-1981 period signaled a shift in the composition of petroleum demand toward gasoline and distillates and away from heavier products. Domestic refiners, again led by the FRS companies, added light product capacity to accommodate this shift.

Increased environmental standards further heightened the capital intensity of U.S. refining during this period. Implementation of major Federal environmental quality legislation in the 1970's confronted refiners with stringent standards for airborne emissions and effluents discharged into waterways. Compliance resulted in added capital expenditures for U.S. refiners (Figure 106). Upgrading and environmental quality measures led to a surge in capital expenditures for U.S. refining over the 1978 through 1983 time span with an attendant rise in capital intensity.

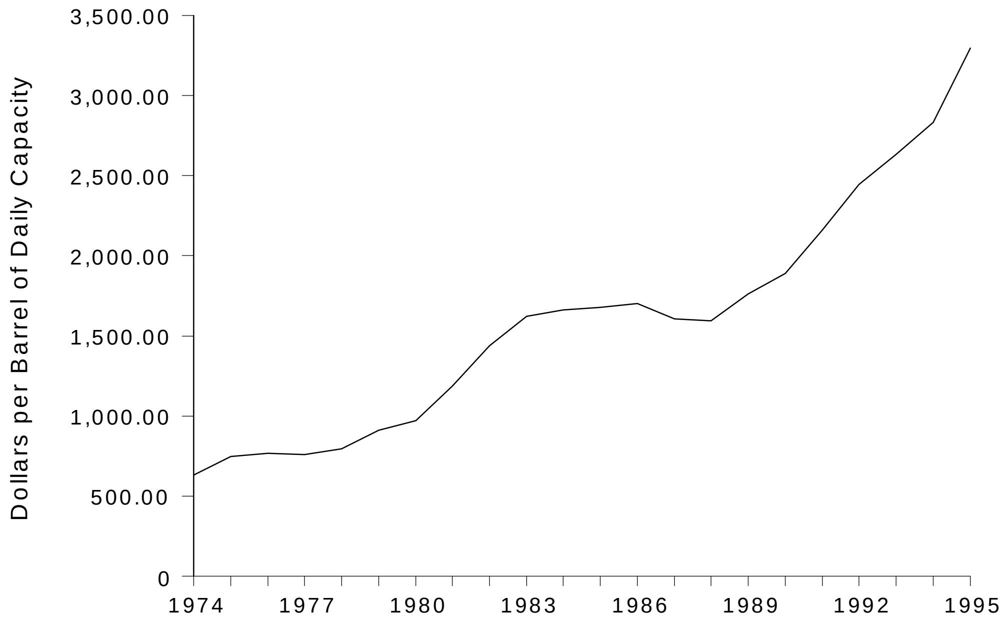
Responses by energy consumers to oil price escalations, together with the deregulation of U.S. petroleum prices in early 1981, made much of U.S. refining capacity uneconomic. While petroleum price regulations were in force, U.S. refining operations yielded moderate rates of return. However, starting in 1981, profitability declined sharply. Narrowing of the price differential between high and low quality crudes during the first half of the 1980's further eroded rates of return. Investments for upgrading refinery input capabilities were premised on a widening of this differential. Therefore, a narrowing tended to impair rates of return.

By 1986, U.S. refiners had shut down or otherwise disposed of plant and equipment representing over 3 million barrels a day of refining capacity. The FRS companies accounted for 75 percent of this reduction. Investment fell off in part because upgrading projects were completed, in part because refiners massively consolidated capacity, and in part because the capital markets were repelled by the poor returns to refining investments. The winding down of pollution abatement expenditures and redeployment of assets gained in the mega-mergers among the FRS companies in the 1981 through 1984 time period also contributed to a falloff in U.S. refining investments. All of these developments flattened the growth in capital intensity.

Capital intensity remained level through most of the 1980's. During this period, net refining margins improved, as did petroleum product demand, leading to increased profitability for U.S. refining and marketing. A widening of the price spread between crude oil qualities also contributed to higher earnings (see Figure 91 in Chapter 7).

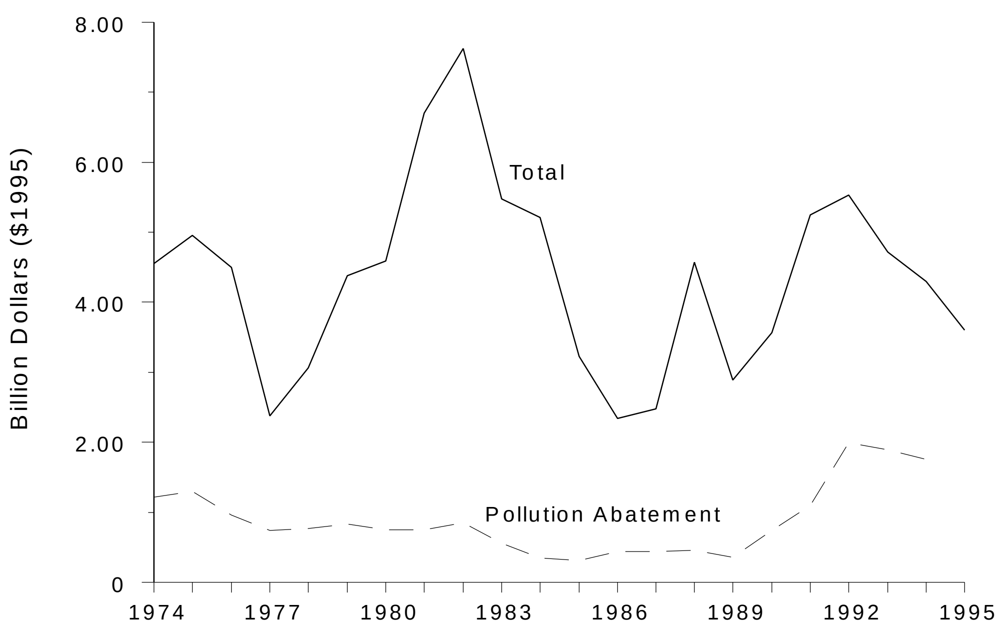
[96]The capital intensity is represented by the ratio of net property, plant, and equipment (PP&E) to barrels per day of crude oil distillation capacity. PP&E is the book value of fixed assets carried on company balance sheets.

Figure 105. Net PP&E per Unit of U.S. Refinery Capacity for FRS Companies



Source: Energy Information Administration (EIA), Form EIA-28.

Figure 106. U.S. Refining Capital Expenditures for FRS Companies



Note: Excludes effects of intra-FRS mergers in 1982 and 1984.
Source: Energy Information Administration (EIA), Form EIA-28. U.S. Department of Commerce, Bureau of the Census, *Pollution Abatement Costs and Expenditures* (various issues) (Washington, DC).

The buoyant rates of return in U.S. refining during the latter half of the 1980's were short lived. In the 1990's, lower margins, due in part to the narrowing of the crude oil price-quality differential, eroded U.S. refining and marketing profits. The adverse effects on profitability were exacerbated by a renewed rise in capital intensity beginning in 1990. Refinery upgrading, in part undertaken to satisfy mandates for reformulated fuels, was the major source of this most recent upswing in capital intensity. Expenditures for pollution abatement played a key role as well.

Growth in motor fuel demand, spurred by the low level of petroleum prices following the oil price collapse in 1986, encouraged investment in light-product capability. The earlier shift in the price-quality spread favoring the use of heavier crude oils encouraged investments in processing capabilities. What differed in the 1990's from the earlier surge in U.S. refining investment was the role of environmentally-related capital expenditures. Starting in the mid-1970's, refiners' environmentally-related capital expenditures trended downwards as the requirements of the Clean Water Act and Clean Air Act were met. By the mid-1980's, environmentally-related outlays were less than 10 percent of overall capital expenditures of U.S. refiners.

In 1990, the Clean Air Act Amendments were enacted by Congress and signed into law. This legislation presented U.S. refiners with added requirements for motor fuels to be met by the end of the decade, including the production of oxygenated gasolines by late 1992, lower sulfur diesel fuels by late 1993, and reformulated gasoline by January 1, 1995. To comply with these measures, FRS refiners stepped up their capital expenditures for the necessary facilities. Environmentally-related capital expenditures quadrupled, accounting for nearly 40 percent of U.S. refining capital expenditures by 1994. The additional capital expenditures raised the capital intensity of U.S. refining.

Examination of the path of capital intensity thus completes the story of U.S. refining profitability over the past 20 years or so (see box, p. 148). For the 1990's in particular, capital intensity grew but refining margins diminished while growth in refined product demand was nearly flat. As a result, the returns to investment in U.S. refining have been low, compared with the rest of U.S. industry.

Petroleum Price Rises Yield Profit Gains in First Half of 1996

Higher petroleum prices in the first half of 1996, particularly gasoline prices, raised concerns about the profits of petroleum companies. In fact, profits from U.S. refining and marketing operations were up sharply. In the first quarter of 1996 (Q196), major integrated refiners (the "majors") reported income from their U.S. refining operations of $223 million (Table 18), which was a turnaround from losses in the first quarter of 1995 (Q195) their worst first-quarter performance in the past 10 years (Figure 107).[97] Similarly, smaller, non-integrated refiners (the "independent refiners") made a substantial recovery from a very poor first quarter the year before. The majors registered a $0.5 billion gain in their U.S. refining profits in the second quarter of 1996 (Q296) while the independent refiners' net income was up 55 percent. For the first half of 1996, both groups of companies more than doubled their earnings compared with the very poor results in the first half of 1995.

Distillate Prices Lift Refining Margins

Based on price and demand patterns, gasoline market developments had a small role in the turnaround in refining profits between Q195 and Q196. Gasoline prices rises were important in the surge in second-quarter profits, but increases in distillate prices contributed more heavily.

The spread between product prices received by refiners and the cost of raw material inputs for their refineries (termed, the gross refining margin) is an important determinant of refining profits, in the short term. For example, there is a strong positive relationship between second-quarter U.S. refining/marketing income and the second-quarter gross refining margin.[98] Although the gross refining margin in Q196 was low in comparison with the general level of margins in the 1990's, it was well above the first-quarter

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[97] Quarterly financial results are available for a consistent group of 13 specialized refiner/marketers and 13 major integrated petroleum companies that separately report data for their U.S. refining/marketing line of business. Integrated major petroleum companies include Amoco, Atlantic Richfield, Chevron, Exxon, Mobil, Murphy Oil, Pennzoil, Phillips, Shell Oil, Sun, Texaco, Unocal, and USX (Marathon). Independent refiners include Ashland, Clark USA, Crown Central Petroleum, Diamond Shamrock, Louisiana Land & Exploration, Mapco, Quaker State, Tesoro Petroleum, Tosco, Total Petroleum, Ultramar, Valero Energy, and Witco. Beginning in the fourth quarter of 1996, due to a merger, Ultramar-Diamond Shamrock replaced the two formerly separate companies.

[98] For the majors, the regression of second-quarter U.S. refining/marketing income per company (Y) on the second-quarter gross refining margin (X) and a dummy variable which is equal to one for 1991-1995 and zero otherwise (DUM), for the years 1987-1995, yielded

$Y = -35.17 - 34.57\,DUM + 14.37X$ with $R^2 = 0.769$ and a t-value of 3.54 for the X-coefficient.

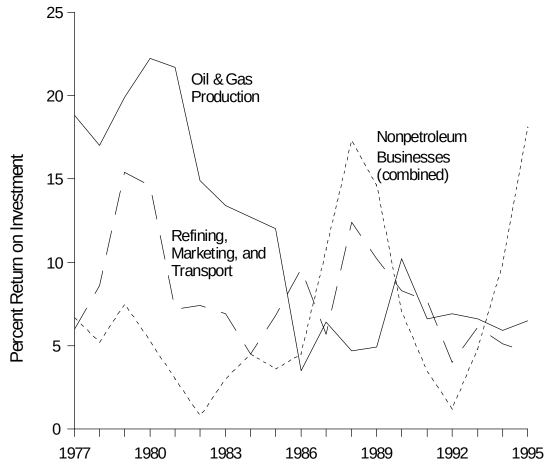
For the independent refiners' second-quarter net income per company (Y), the regression analysis yielded

$Y = -9.38 - 5.41\,DUM + 3.73X$ with $R^2 = 0.942$ and a t-value of 9.07 for the X-coefficient.

Perspectives on Petroleum Profitability

Over the past 20 years or so, downstream petroleum operations have rarely been the most profitable of the majors' lines of business. The figure to the right shows annual returns on investment for the FRS companies' worldwide oil and gas production operations, downstream petroleum (refining, marketing, and transport) operations, and the aggregate of their operations outside petroleum and natural gas (the share of these latter operations accounted for by chemicals, based on value of assets, ranged from 29 percent in 1984 to 59 percent in 1992). Three periods are distinguishable from the figure to the right.

Return on Investment by Lines of Business for FRS Companies



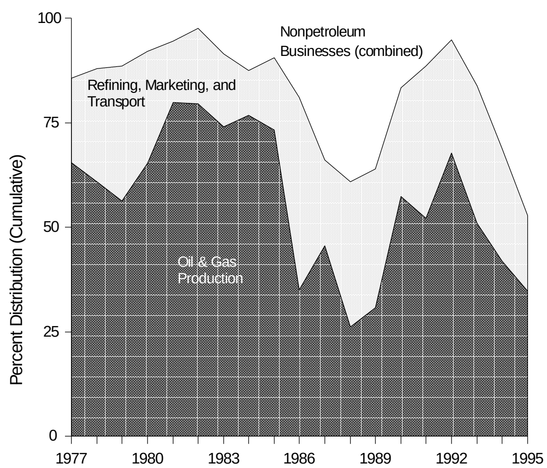
Note: Return on investment = net income contribution divided by net investment in place.

Source: Energy Information Administration (EIA), Form EIA-28.

The period of high oil prices. From 1974 through early 1981, oil prices sporadically escalated. Dollar-denominated crude oil prices peaked in the first quarter of 1981 at close to $40 per barrel, a tenfold rise from 1973's oil prices. Accordingly, the rate of return to oil and gas investments rose sharply and was, by far, the majors' most profitable line of activity as well as the source of the major share of net income (figure below, right), even as oil prices gradually declined from 1981 through 1985. Downstream profitability also rose sharply in the late 1970's, in significant part reflecting the rising value of petroleum inventories, but never came close to upstream rates of return. Downstream profits plunged after peaking in 1980. Thereafter, refiners both in the United States and abroad shutdown or otherwise divested massive amounts of refining capacity which had become uneconomic. The declining returns to downstream operations in the early 1980's reflected the financial difficulties of that period.

The 1986 oil price collapse and aftermath. Oil prices collapsed in early 1986, and, by mid-year, fell to levels not seen since 1974. On an inflation-adjusted basis, oil prices for the remainder of the 1980's were generally below the levels of the 1974-1985 period. Upstream profitability plunged in 1986 and remained well below levels realized earlier during the period of high oil prices. Downstream profitability, by contrast, rose steeply in the late 1980's. Lower oil prices led to increased demand for petroleum products. Refiners, overall, completed their retrenchments at just about the time that oil prices collapsed. Both developments favored an upswing in downstream profitability, as did lower crude oil input prices. Lower feedstock costs, stemming from low oil prices, also contributed to a surge in chemical profits. The sharp rise in the profitability of nonpetroleum businesses was largely a reflection of developments in the majors' chemical operations.

Shares of Allocated Income by Lines of Business for FRS Companies



Source: Energy Information Administration (EIA), Form EIA-28.

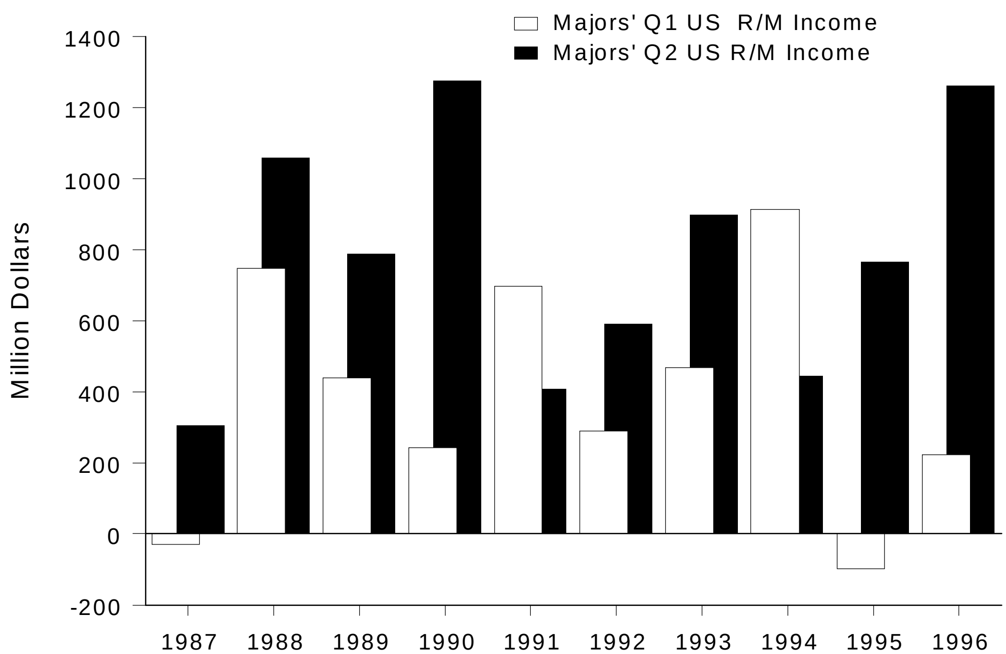
The 1990's. Crude oil prices rose sharply in the last two quarters of 1990, largely due to the effects of Iraq's invasion of Kuwait. After the expulsion of Iraqi troops in early 1991, oil prices have tended to vary in the same range prevailing in the late 1980's (on an inflation-adjusted basis). Upstream operations benefitted from the war-induced oil price spike in 1990 but then declined. Although upstream profitability in the 1990's has not come close to pre-collapse levels, it is clearly higher than the levels of 1986-1989. Cost-cutting in the 1990's has helped raise the returns to oil and gas production. Downstream operations have also been a focus of cost-cutting in the 1990's, but, despite these efforts, downstream profitability has trended downwards. The increased share of businesses outside petroleum and natural gas in recent years (see figure to right) was largely due to a surge in chemical earnings.

Table 18. Quarterly Income in U.S. Refining and Marketing
(Million Dollars)

	1995	1996	Percent Change
U.S. Refining/Marketing Income for the Majors (13 Companies)			
First Quarter	-100	223	NM
Second Quarter	765	1,261	64.8
Net Income for Independent Refiners (13 Companies)			
First Quarter	4	121	3,025.0
Second Quarter	184	286	55.4

NM = Not meaningful.
Source: Company 1996 reports to shareholders.

Figure 107. Majors' First and Second Quarter U.S. Refining/Marketing Net Income



Source: Companies' quarterly reports to shareholders.

margin of the year before (Table 19). In Q195, the refining margin fell to a 6-year low, squeezed by a combination of a slight rise in crude oil input costs and downward pressures on gasoline and distillate prices. The modest recovery in the overall refining margin largely reflected the effects of an especially cold winter in 1995-1996, particularly in March. Distillate prices were up 17 percent and the price of propane rose 22 percent between Q195 and Q196. In contrast, gasoline prices were up 6 percent, just matching the rise in crude oil input prices.

Demand growth also favored higher refining profits in Q196 relative to Q195. The quantity of total refined products supplied was up 4 percent over this period, mainly reflecting the greater demand for space heating fuels. Improved economic conditions also contributed to overall petroleum demand, with real GDP growing 2 percent between Q195 and Q196. The total amount of distillate fuel oil and propane supplied was up 5 percent. Residual fuel oil volumes were up 7 percent, fed by electric utility demand. However, growth in gasoline demand was nearly flat.

Table 19. Refined Product Resale Prices, Margins, and Products Supplied, First and Second Quarters, 1995 and 1996

	Q195	Q196	Q295	Q296
Resale Prices (Dollars per Barrel)				
Motor Gasoline	25.24	26.72	28.92	31.82
Distillate	21.14	24.83	22.42	27.07
Kerojet and Kerosene	22.09	25.65	22.43	26.23
Propane	14.63	17.78	13.82	15.46
Other Products	15.97	18.55	17.48	18.68
Composite Product Price	22.75	25.16	26.12	29.27
Composite Refiner Acquisition Cost of Crude Oil	16.99	18.47	18.24	20.45
Gross Refining Margin	5.76	6.69	7.88	8.82
Products Supplied (Thousand Barrels per Day)				
Motor Gasoline	7,477	7,511	7,921	7,985
Distillate	3,463	3,616	3,089	3,231
Jet Fuel	1,513	1,605	1,425	1,505
Propane and Other Products	5,187	5,560	5,084	5,193
Total Products Supplied	17,640	18,292	17,519	17,914
Retailer Margin (Dollars per Barrel)				
Motor Gasoline	5.68	5.09	5.34	6.14
Diesel Fuel	1.09	1.00	0.98	1.07

Sources: Energy Information Administration (EIA), *Petroleum Marketing Monthly,* August 1996, DOE/EIA-0380(96/08) (Washington, DC, August 1996) and *Petroleum Supply Monthly,* August 1996, DOE/EIA-0109(96/08) (Washington, DC, August 1996).

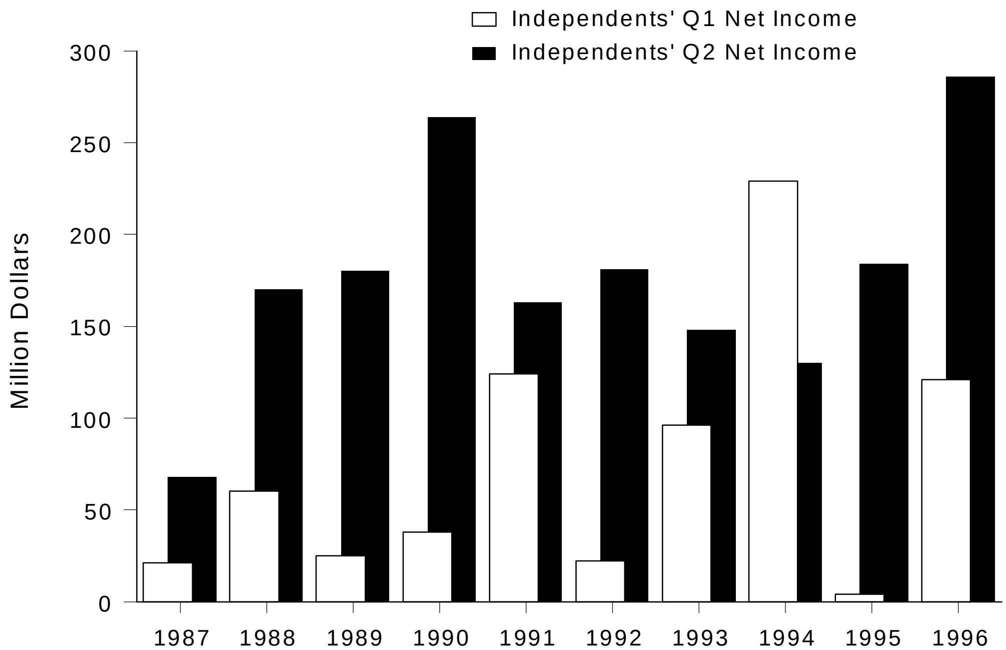
In the second quarter, the rise in gasoline prices outpaced the rise in crude oil prices compared with Q295, $2.91 per barrel vs. $2.21. However, overall distillate product prices registered a steeper rise of $4.65 per barrel over the same period. Similarly, while motor gasoline demand rose nearly 1 percent, distillate demand was up nearly 5 percent, reflecting strong demand for diesel and replenishment of inventories.

Second-quarter U.S. Refining Profits Reach a 10-Year Peak in 1996

Public concerns about U.S. refinery profits were probably most intensely focused on the second quarter of 1996, since the rise in gasoline prices began late in the first quarter and continued into the second quarter. The majors' second-quarter financial results for their U.S. refining/marketing operations were at a 10-year peak, surpassing the previous peak in 1990, when crude oil gluts preceding the Iraqi invasion of Kuwait yielded record refining margins (Figure 107). The independent refiners recent second-quarter financial results also surpassed those of 1990 (Figure 108).

It is probably worthwhile to note that second-quarter profits in 1996 exceeded expectations based on the estimated relationships between profits and the gross refining margin noted above. Based on these relationships, the actual value of Q296 refining/marketing profits were 1.7 times the predicted value for the majors and 1.3 times the predicted value for the independents. One source of higher profits in this quarter not accounted for by the above relationships appeared to be a wider spread between wholesale prices paid and retail prices charged for gasoline by retailers. The retailer margin in Q296 was up 2 cents a gallon (15 percent) from the previous year (Table 19). Since most of the refiners that reported second-quarter financial results have gasoline marketing networks, an increased spread in the retailer margin would contribute to improved bottom-line results.

Figure 108. Independent Refiners' First and Second Quarter Net Income



Source: Companies' quarterly reports to shareholders.