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:

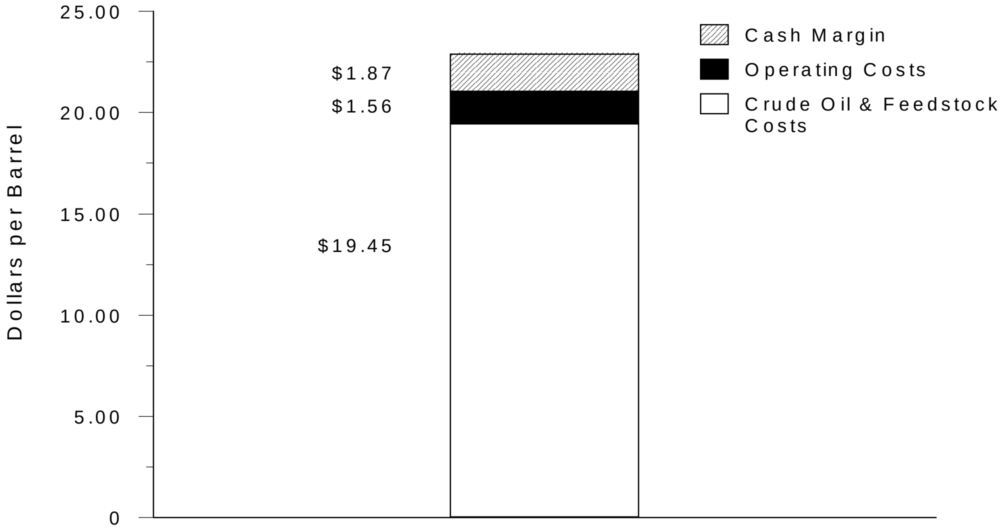
$$\begin{aligned}\textit{Cash Margin} &= \sum_{i}^{N} (\textit{Price Product}_i \times \textit{Yield Product}_i)\\ &- \textit{Crude Cost}\\ &- \textit{Other Feedstock Cost}\\ &- \textit{Fuel plus Other Variable Costs}\\ &- \textit{Operating, Maintenance Cost}\end{aligned}$$

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;

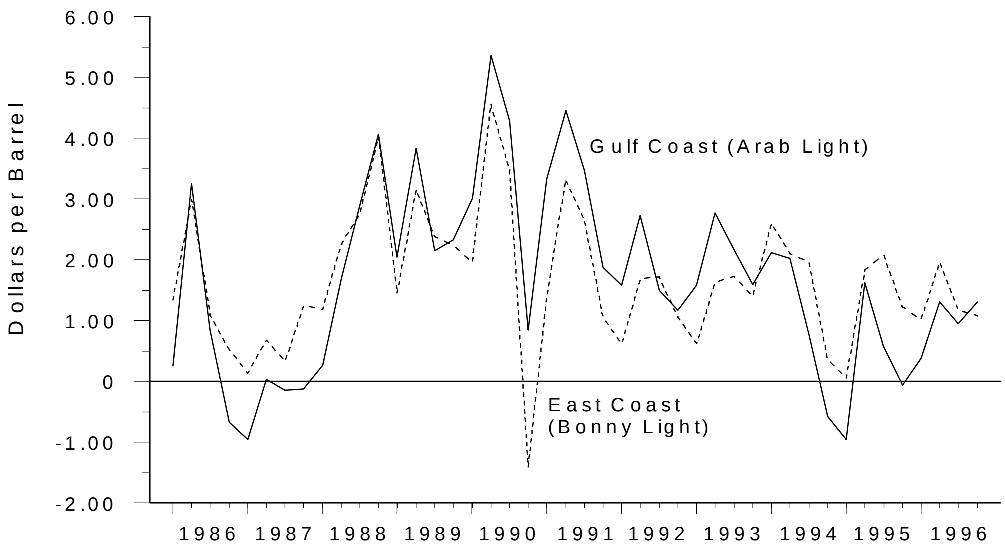
[85] While West Coast refiners experienced the same types of underlying economics, they also were preparing for unique California clean fuel specifications. As a result, they are not considered in this report.

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.

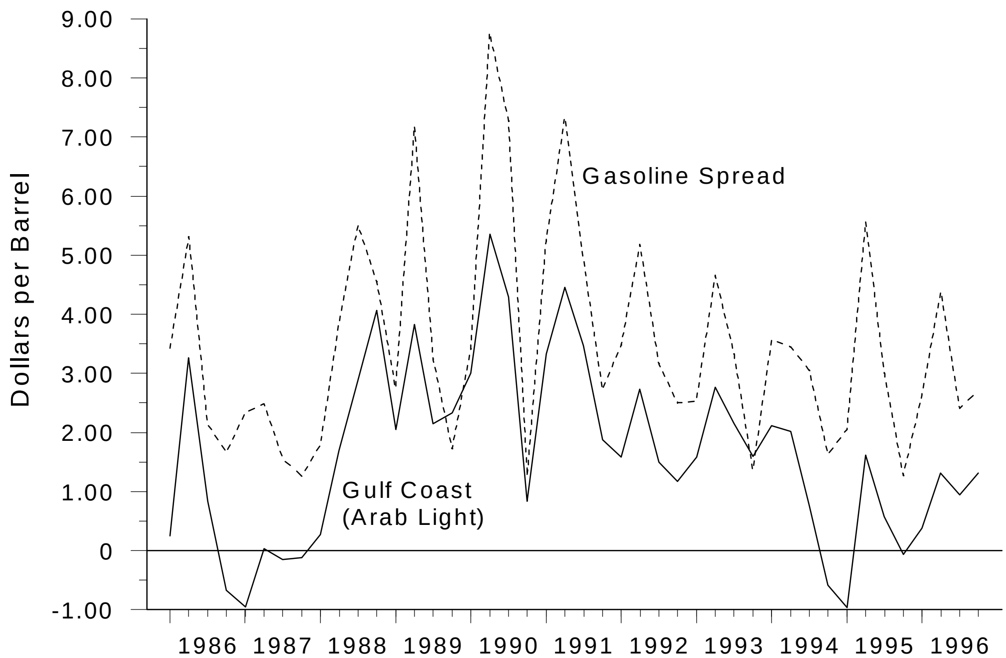
This section discusses market factors that explain these variations, including product and crude supply/demand balances, the interactions of light versus heavy product demand, light versus heavy crude availability, the availability of conversion capacity, and changing product specifications brought about 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*.

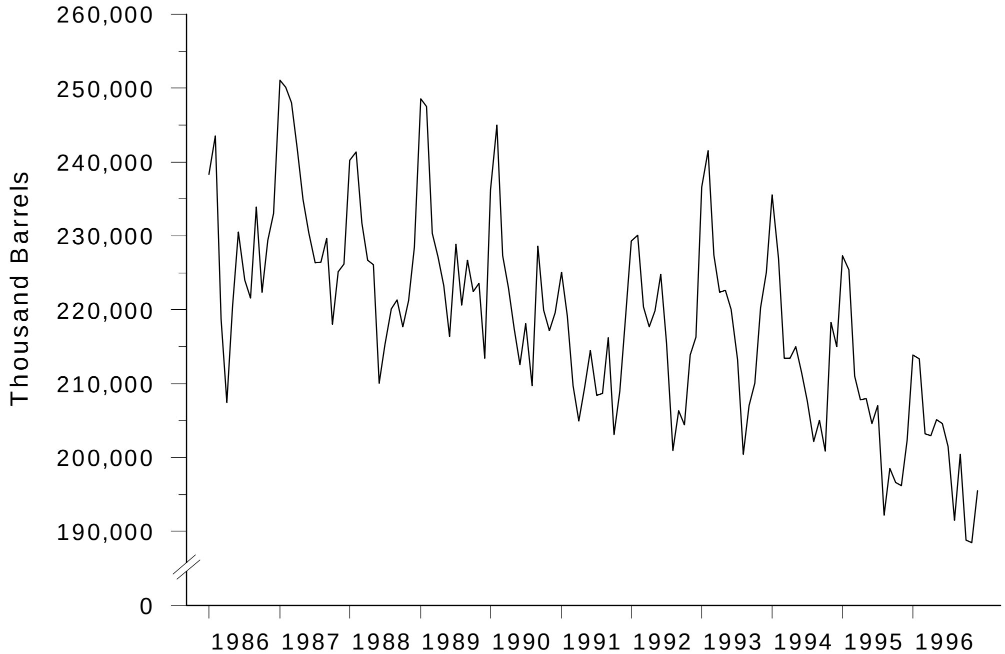
Refining margins are generally lowest during the winter quarters (fourth and first quarters) when gasoline demand and prices have fallen and inventories are building. The weather's impact on distillate prices tends to determine if the first quarter or the fourth quarter is the lowest margin quarter. 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.

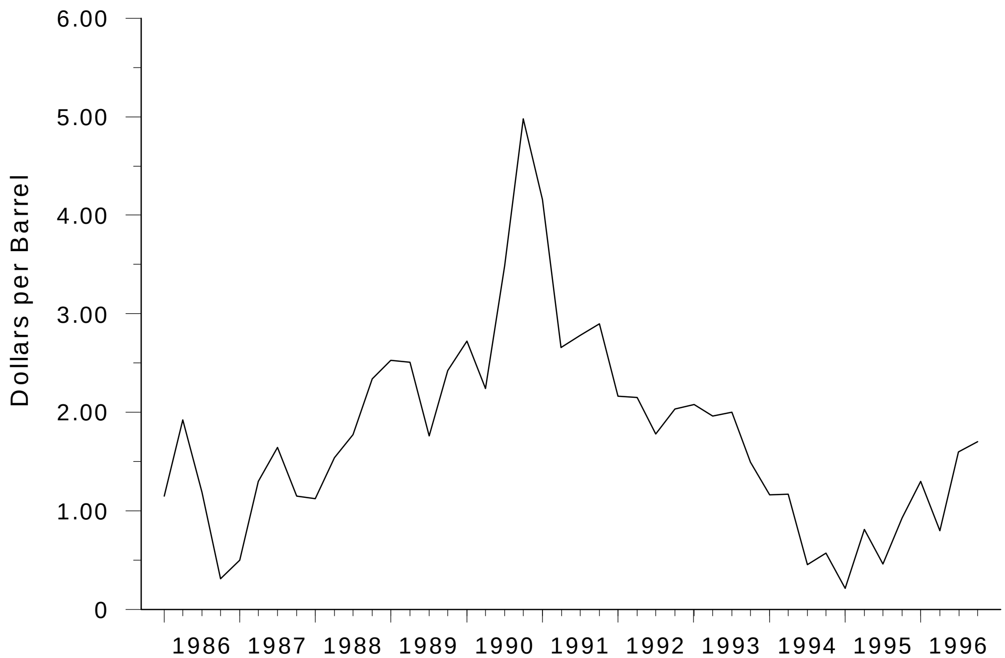
Light Versus Heavy Balances for Crude and Products Affect Margins

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

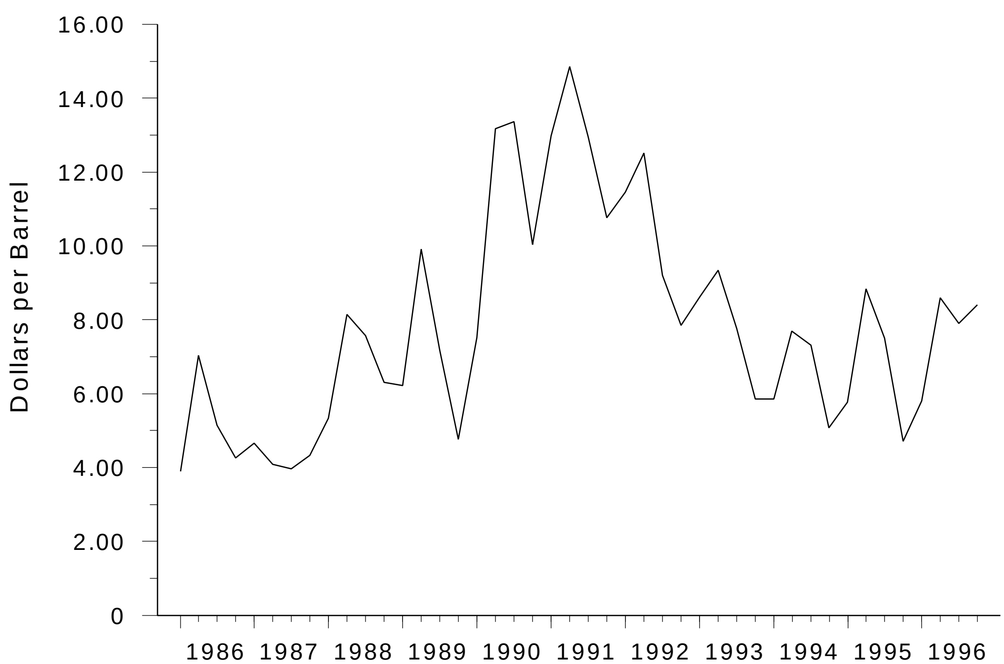
[88]The increasing, light-to-heavy crude oil supply ratio had a depressing effect on margins during the 1990's, as discussed in more detail under long-term trends. Light sweet crude supply was especially abundant during this time, and the light-heavy crude price difference continued to drop substantially, 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).

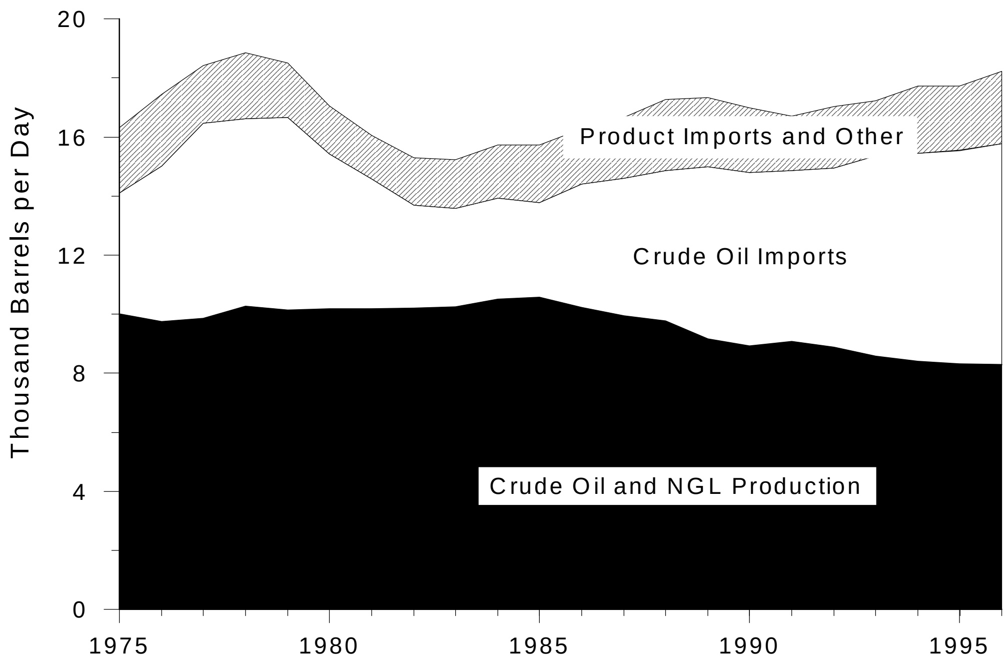
In the 1990's, conversion capacity was only part of the downward pressure on light-heavy differentials. The primary factor driving the decline was a substantial increase in light, sweet crude oil production in the Atlantic Basin market region. The largest part of the increase came from the North Sea, 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.

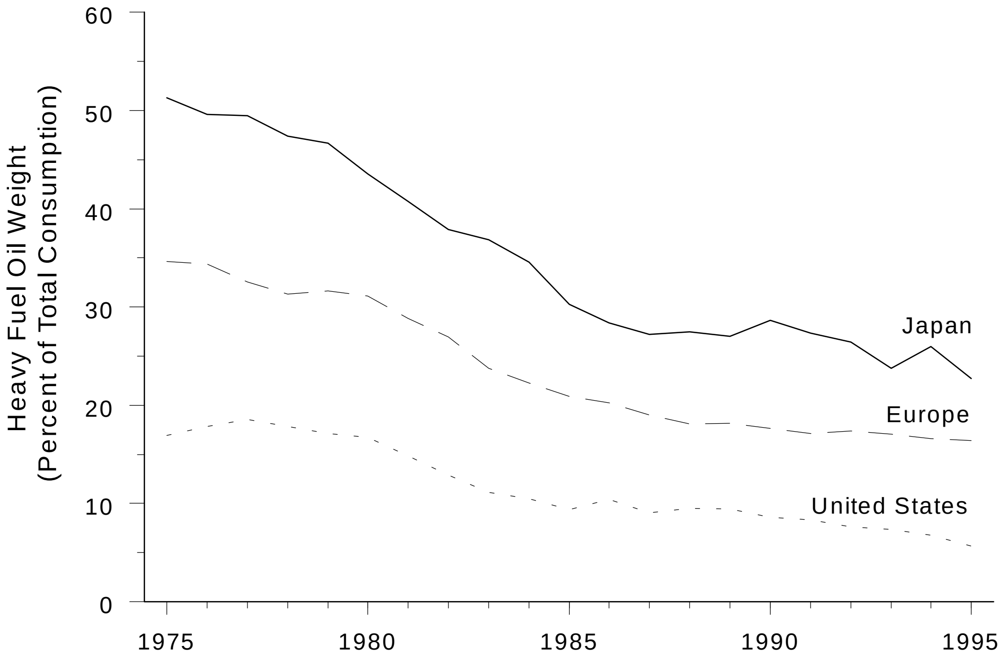
Figure 93. U.S. Petroleum Supply



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.

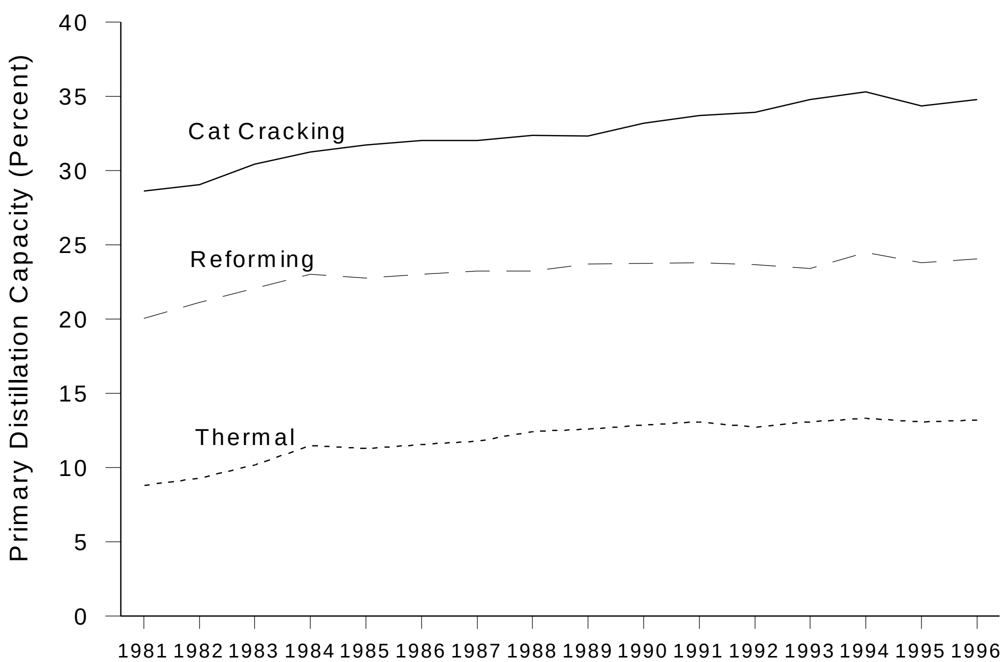
Before showing the full margin impact of similar refineries processing light versus heavy crude oils, the link between the light-heavy differential and average refinery margins can be explored by observing the simple spread between gasoline prices and light and heavy crude prices. Due to gasoline's strong 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)



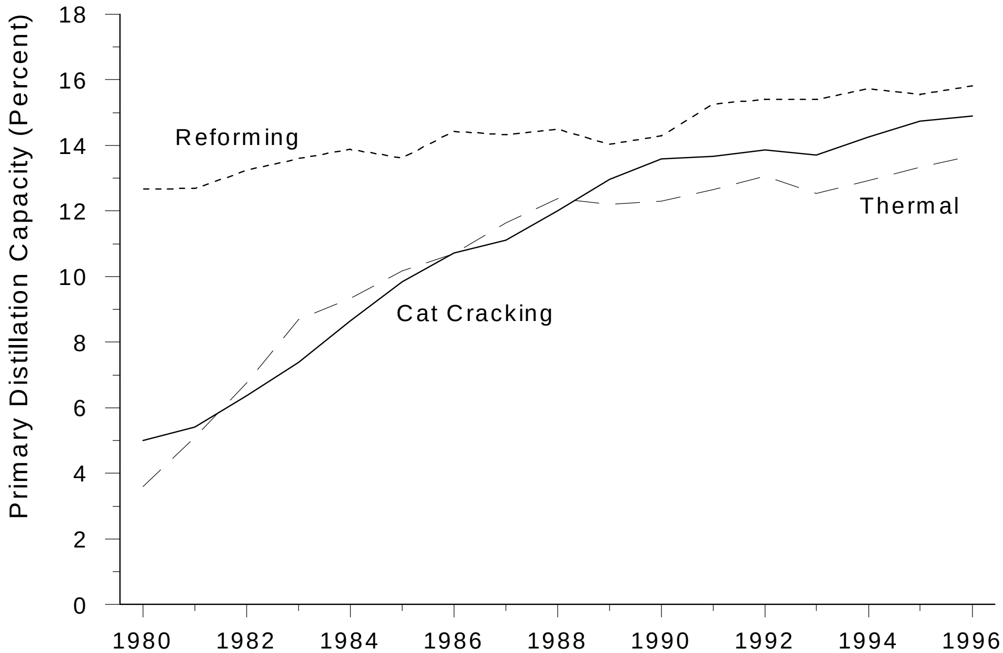
Source: British Petroleum, *Statistical Review of World Energy, 1996*.

Figure 95. U.S. Downstream Processing Capacity



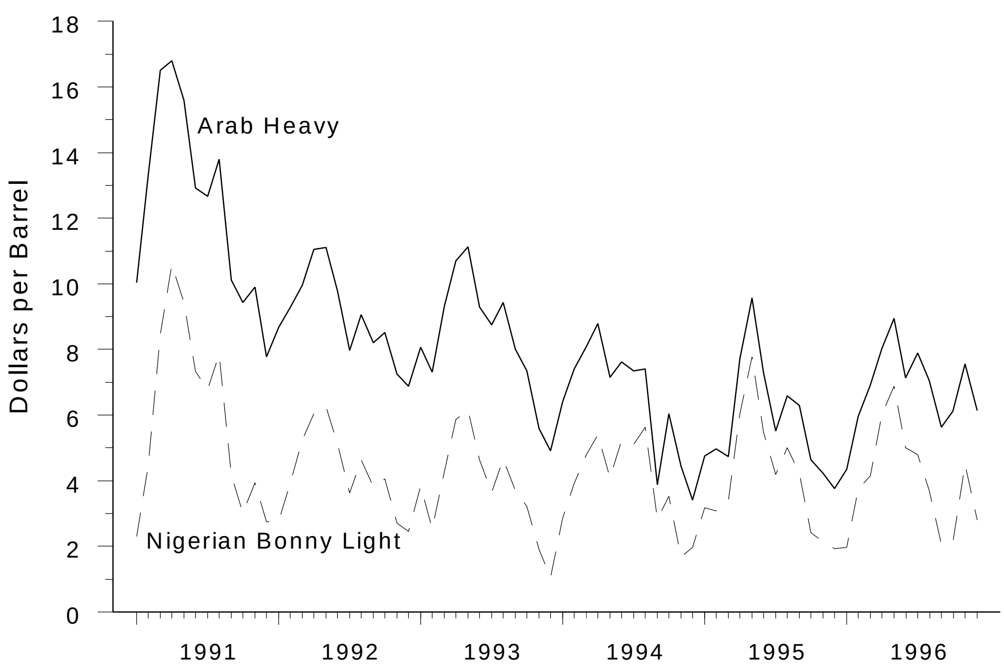
Sources: **1981-1995:** Energy Information Administration (EIA), Form EIA-820 "Annual Refinery Report." **1995:** The stream day capacities are projected capacities reported on Form EIA-820 "Annual Refinery Report" (1995)." **1996:** Number of refineries and crude distillation capacity from Form EIA-810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

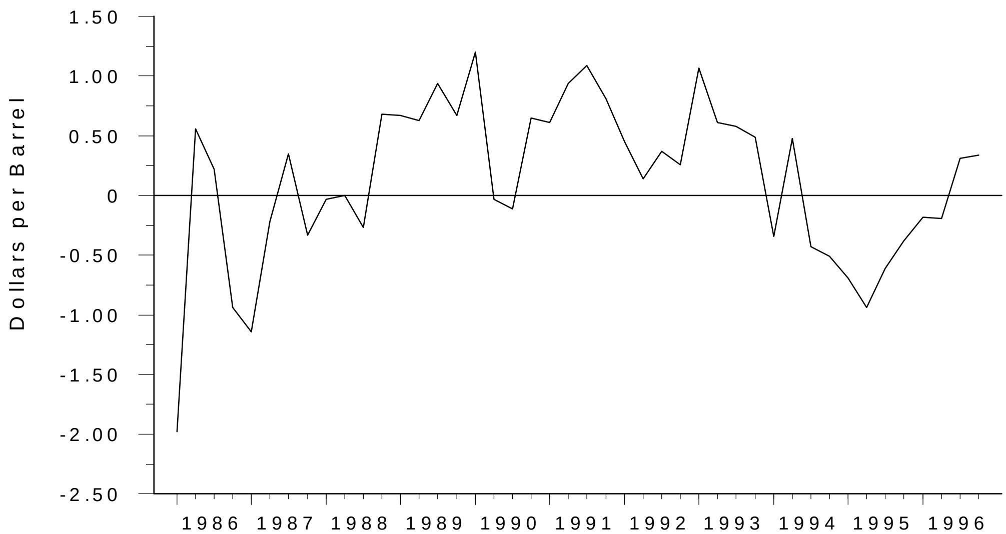
In summary, the market dynamics surrounding the interactions of light versus heavy product demand, light versus heavy crude availability, and availability of conversion capacity all contributed to the long-term margin variations over the past decade. These market dynamics affected not only those refiners 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

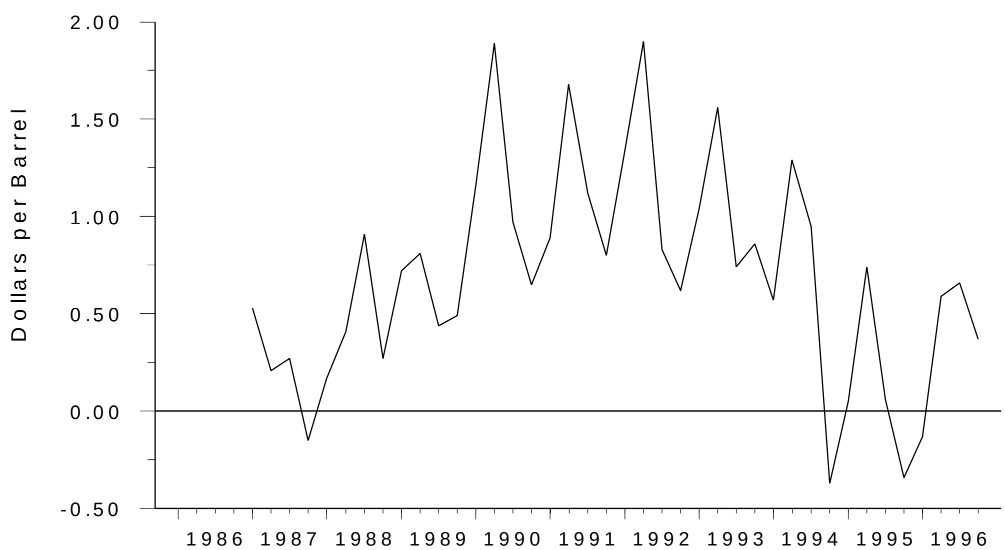
[89]Lidderdale, Tancred, Nancy Masterson, Nicholas Dazzo, "U.S. Refining Capacity Utilization," Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109 (95/10) (October 1995), pp. xxxiii-xxxix.

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.

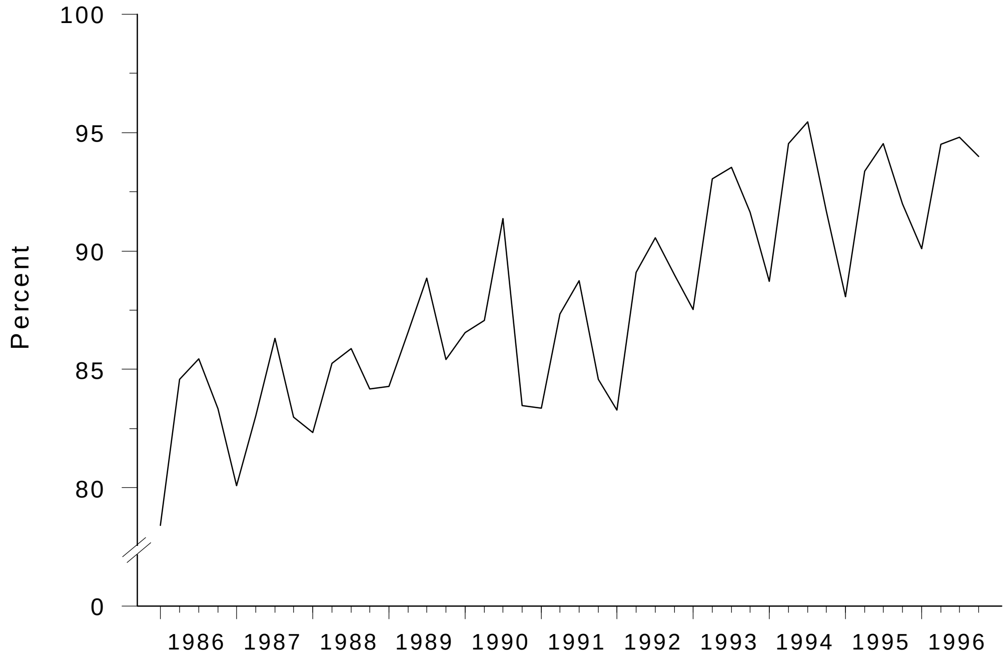
U.S. refinery utilization must also be viewed in the context of world refining capacity. In the future, even if U.S. refineries begin to feel capacity constraints, other countries may be able to produce products in excess of their own needs and ship them to the United States more cheaply than U.S. refiners 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

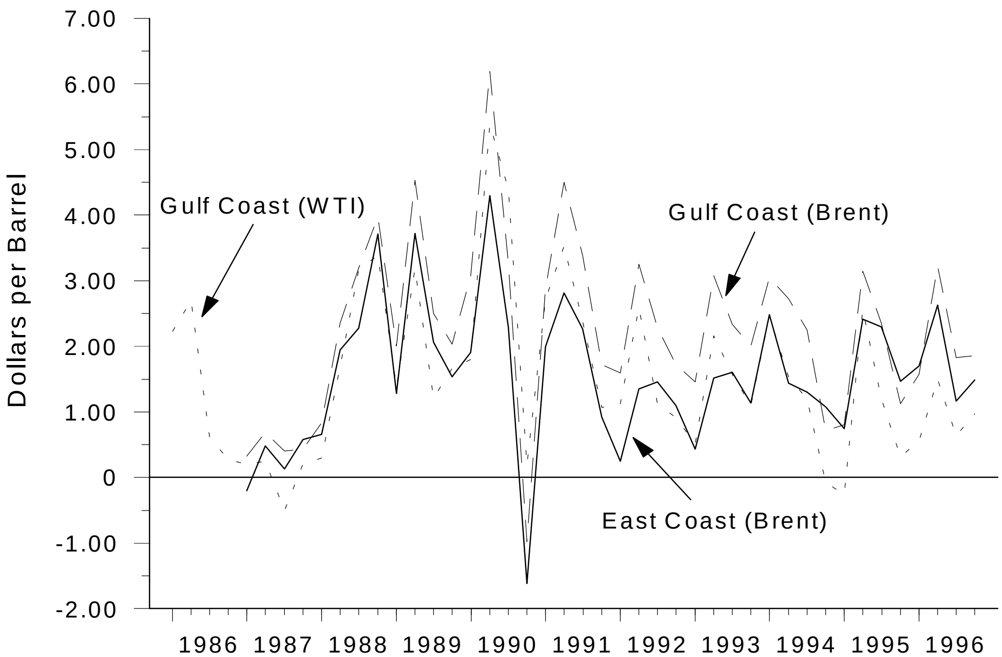
Refinery	90Q1	Q2	Q3	Q4	91Q1	Q2	Q3	Q4	92Q1	Q2	Q3	Q4	93Q1	Q2	Q3	Q4	94Q1	Q2	Q3	Q4
BONNY LT -EC	1.96	4.56	3.47	-1.41	1.42	3.32	2.66	1.05	0.62	1.69	1.72	1.06	0.62	1.63	1.73	1.40	2.60	2.10	1.97	0.37
BRENT-EC	1.91	4.30	2.29	-1.62	1.99	2.81	2.27	0.92	0.25	1.35	1.46	1.10	0.43	1.52	1.60	1.14	2.48	1.44	1.30	1.08
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.