Federal Trade Commission
Bureau of Economics

The Petroleum Industry: Mergers, Structural Change, and Antitrust Enforcement

An FTC Staff Study






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List of Frequently Used Abbreviations and Acronyms

ANS	Alaska North Slope Crude Oil
AOP	Association of Oil Pipelines
API	American Petroleum Institute
BBL	Barrel
CAFE	Corporate Average Fuel Economy
CARB	California Air Resources Board
CR	Concentration Ratio
DOJ	U.S. Department of Justice
DTW	Dealer Tank Wagon Price
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FBO	Fixed Base Operator
FCC	Fluid Catalytic Cracking
FERC	U.S. Federal Energy Regulatory Commission
FRS	Financial Reporting System of the Department of Energy
FTC, Commission	U.S. Federal Trade Commission
GAO	General Accounting Office/Government Accountability Office
HHI	Herfindahl-Hirschman Index
HSR	Hart-Scott-Rodino Act
LPP	Light Petroleum Product
MBD	Thousand Barrels per Day
Merger Guidelines	DOJ and FTC Horizontal Merger Guidelines
MES	Minimum Efficient Scale
MMBD	Million Barrels per Day
MTBE	Methyl Tertiary Butyl Ether
NGL	Natural Gas Liquids
NYMEX	New York Mercentile Exchange
OCS	Outer Continental Shelf
OPEC	Organization of Petroleum Exporting Countries
OPIS	Oil Price Information Service
PADD	Petroleum Administration for Defense District
PPM	Parts per Million
RFG	Reformulated Gasoline
ROE	Return on Equity
ROI	Return on Investment
RVP	Reid Vapor Pressure
SPR	Strategic Petroleum Reserve
SSNIP	Small but Significant and Non-transitory Increase in Price
TAPS	Trans-Alaska Pipeline System
ULSD	Ultra-low Sulfur Diesel

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Chapter 1

Introduction and Executive Summary

The petroleum industry occupies an unusually prominent place in the American economy. As with few other products, consumers are acutely aware of variations in the price of gasoline and home heating oil. Not only do changes in the prices of these commodities affect consumers directly, supply conditions for petroleum products also influence many sectors of the economy. Perhaps no other industry's performance is so visibly and deeply felt.

Over the past two decades, the petroleum industry has undergone a structural upheaval, punctuated by a burst of large mergers in the late 1990s. Various forces have spurred the transformation. Technological, economic, and regulatory factors have led toward reliance on a smaller number of larger, more sophisticated refineries that can process different kinds of crude oil more efficiently. The development of crude oil spot and futures markets has reduced the risks of acquiring crude oil through market transactions, relative to ownership of crude oil extraction and production assets, contributing to a decline in vertical integration between crude oil extraction and production and refining among the major oil companies. Domestic crude oil production has fallen, and foreign sources have supplied an increasing share of the crude oil refined in the United States, thus enhancing the importance of competition in the world market for crude oil.

Changes in crude oil prices have accounted for approximately 85% of the increases and decreases in U.S. motor gasoline prices over the past two decades.[1] The run-up in crude oil prices in 2004 to more than $40 a barrel, accompanied by substantial increases in U.S. gasoline prices, has highlighted the critical nature of this relationship. Consumption of refined petroleum products in the U.S. grew on average about 1% per year between 1985 and 2002, or about 18% over the entire period. This increase in consumption has been met primarily by increased production at U.S. refineries, with these refineries continuing to satisfy more than 90% of U.S. demand and, since the mid-1990s, typically operating at annual

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[1] A simple regression of the monthly average national price of gasoline on the monthly average price of West Texas Intermediate crude oil shows that the variation in the price of crude oil explains approximately 85% of the variation in the price of gasoline. This percentage may vary across states or regions. Data for the period January 1984 to October 2003 were used for this regression. *See* Prepared Statement of the Federal Trade Commission Before the Committee on Energy and Commerce, Subcommittee on Energy and Air Quality, U.S. House of Representatives, *Market Forces, Anticompetitive Activity and Gasoline Prices – FTC Initiatives to Protect Competitive Markets* (July 15, 2004) [hereinafter "FTC Energy and Commerce Committee Statement"]. This is similar to the range of effects given in United States Department of Energy/Energy Information Administration, *Price Changes in the Gasoline Market: Are Midwestern Gasoline Prices Downward Sticky?*, DOE/EIA-0626 (Feb. 1999). More complex regression analysis and more disaggregated data may give somewhat different estimates, but the latter estimates are likely to be of the same general magnitude.

utilization rates of more than 90%. A sound understanding of these and related commercial phenomena is critical for the formulation of sensible competition policy for the petroleum industry.

I. The Goals and Major Themes of the Report

The Federal Trade Commission ("FTC" or "Commission") is well-suited to illuminate the causes and consequences of the structural and behavioral developments sketched above.[2] Since the early 1980s, the FTC has been the federal antitrust agency primarily responsible for addressing petroleum industry competition issues. In the past two decades, the Commission has focused close attention on petroleum industry matters and has done so by invoking all of the policy tools at its disposal – the prosecution of cases, the preparation of studies, and the presentation of competition policy guidance to other government bodies. In the course of these activities, the FTC has assembled the world's preeminent base of competition policy expertise and enforcement expertise for this sector.

This Report mainly addresses a core component of the Commission's petroleum industry program – the review of mergers. In this role, the FTC has devoted substantial resources to investigating mergers and, in a number of instances, to blocking or modifying specific transactions. This Report is the third FTC study since 1980 to examine structural change and other evolving conditions in this industry.[3] Like its predecessors, this Report has two basic goals: to inform public policy concerning competition in the petroleum industry, and to make more transparent how the Commission analyzes mergers and other competitive phenomena in this sector. The Report develops five major themes:

- Mergers of private oil companies have not significantly affected worldwide concentration in crude oil. This fact is important, because crude oil prices are the chief determinant of gasoline prices. However, competitive effects may arise in other sectors and markets of the petroleum industry and can have an effect on gasoline prices.[4]

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[2] The significance of the petroleum industry has been reflected in the FTC's competition policy work since Congress enacted the Federal Trade Commission Act in 1914. For example, in the first 10 years of its operations, the Commission reported several times on public policy issues in this sector. *See, e.g.,* Federal Trade Commission, *Advance in the Price of Petroleum Products: Report in Response to House Resolution No. 501* (June 1, 1920); Federal Trade Commission, *Report on the Pacific Coast Petroleum Industry, Parts I and II* (Apr. 7, 1921 and Nov. 28, 1921); Federal Trade Commission, *Report on Foreign Ownership in the Petroleum Industry* (Feb. 12, 1923).

[3] The FTC released its first petroleum merger report in 1982. Federal Trade Commission, *Mergers in the Petroleum Industry* (Sept. 1982) [hereinafter "1982 Merger Report"]. The 1982 Merger Report provided information on the structure of the industry, the level of merger activity and its impact on industry structure during the preceding decade, the reasons for industry mergers, and, importantly, the FTC's methodology for reviewing petroleum mergers. In 1989, the FTC released a Bureau of Economics staff report that provided a limited update of the Commission's 1982 Merger Report. Staff Report of the Bureau of Economics, Federal Trade Commission, *Mergers in the U.S. Petroleum Industry 1971-1984: An Updated Comparative Analysis* (May 1989) [hereinafter "1989 Merger Report"]. The 1989 study focused mainly on merger activity between 1982 and 1984.

[4] This Report analyzes the petroleum industry at five sectors or levels of operation: crude oil production and reserves; bulk transport of crude oil; refining; bulk

- Despite some increases over time, concentration for most levels of the petroleum industry has remained low to moderate.
- Intense, thorough FTC merger investigations and enforcement have helped prevent further increases in petroleum industry concentration and avoid potentially anticompetitive problems and higher prices for consumers.
- Economies of scale have become increasingly significant in shaping the petroleum industry.
- Industry developments have lessened the incentive to be vertically integrated throughout all or most levels of production, distribution and marketing. Several significant refiners have no crude oil production, and integrated petroleum companies today tend to depend less on their own crude oil production.

To develop these themes, the Report draws mainly upon the Commission's extensive experience with petroleum industry mergers. The Report also taps the knowledge the agency has gained from its non-merger investigations and other studies of the industry, particularly of price movements.[5] As such, this Report is one element of a larger, continuing FTC policymaking program that seeks to improve our understanding of developments in the petroleum industry, to disseminate information on factors that influence prices and other market outcomes, and to use the Commission's law enforcement powers to challenge violations of the nation's antitrust laws.[6]

II. Organization of the Report and the Executive Summary

The Report has nine chapters. Chapter 2 describes the FTC's merger enforcement actions to maintain competition in petroleum-related markets during the past 20 years.[7] Chapter 3 provides an overview of industry trends in production, pricing, capital expenditures and rates of return. Chapter 4 provides an analysis of merger activity for the period 1985 through 2001 and concludes with a discussion of the efficiencies that merging firms have claimed in various larger transactions. Chapters 5 through 9 examine in greater detail trends at specific industry levels: crude oil production and reserves; bulk transport of crude oil; refining; bulk transport of refined products; and product terminals and gasoline marketing.

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transport of refined products; and product terminals and gasoline marketing.

[5] For example, the FTC conducted an extensive investigation of pricing in the Midwest following a substantial price increase in that area in spring 2000. In 2001, the FTC completed an extensive investigation of West Coast gasoline prices in response to concerns about price differences within the area. In addition, in 2002 the FTC initiated its Gas Price Monitoring project to identify unusual price movements. These investigations and projects are discussed further, *infra* at 17-19, and in FTC Energy and Commerce Committee Statement, *supra* note 1, at 11-24.

[6] This Report focuses on one condition – merger-related changes in industry structure – that influences competition. As indicated in Commission presentations, many other factors affect petroleum prices. *See, e.g.,* FTC Energy and Commerce Committee Statement, *supra* note 1.

[7] Table 2-5 provides a detailed list of the FTC's merger actions, including markets in which divestitures and other types of relief were ordered. The appendix to Chapter 4 describes the methodology used in identifying "Large Petroleum Company" mergers.

This Executive Summary provides an overview of trends in the oil industry and describes FTC enforcement activities to maintain competition in petroleum-related markets.

III. Overview of Petroleum Industry

The petroleum industry is institutionally complex, but can be divided into two basic levels: upstream and downstream. Upstream includes all activities necessary to extract oil from the earth: exploration, geological assessment of potential oil fields, and the drilling and operation of wells to produce a flow of crude oil. Downstream activities include transporting crude oil to refineries; refining crude oil into finished products; transporting finished products from refineries to storage terminals; and marketing by wholesalers and retailers.

Before this brief tour of the industry, one introductory methodological note is appropriate. The Report often presents national industry share and concentration data for descriptive purposes and to show industry trends. These measures are generally unsuitable for analyzing the effects of mergers on competition in relevant antitrust markets. The FTC uses its subpoena and other investigatory powers to obtain company-specific proprietary data to evaluate properly defined relevant markets. In general, publicly available information is insufficient to conduct a comprehensive investigation of the likely effects of a proposed merger. As discussed repeatedly throughout the Report, the delineation of relevant antitrust markets requires a careful, realistic assessment of practical demand and supply alternatives.

A. Crude Oil Exploration and Production

Crude oil is the primary input into the production of motor gasoline and other refined petroleum products. For example, it typically accounts for approximately 38% of the cost of each gallon of gasoline. Crude oils from different fields usually have different chemical characteristics and are most importantly distinguished by density and sulphur content. As noted below, refineries generally have become better able to process different types of crude oil, enabling them to substitute among different crude oils more easily. Heavy and sour (high sulphur) crudes generally sell at lower prices because, compared to lighter and sweeter crudes, they yield smaller amounts of high value products such as gasoline and jet fuel. Nevertheless, the prices of major world crudes have tended to track each other closely.[8] This suggests that the price of one crude cannot get too much out of line with the prices of the other crudes without causing refiners to substitute among crudes.

Spot and futures markets for buying crude oil have expanded significantly since the late 1970s. Between 1979 and 1989, the amount of world crude oil traded on a spot basis rose from 1-3% to 33%. The growth of futures markets for crude oil during the 1980s was similarly dramatic.

Domestic production of crude oil has fallen as many inland oil fields have begun to run dry. Off-shore production has offset this decline to some extent,

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[8] *See* Chapter 5, Figure 5-1, *infra.*

but not entirely. At the same time that domestic crude oil output has dropped, U.S. refiners have expanded their production of refined products and, therefore, have required additional crude oil supplies.

Falling domestic output has increased the importance of foreign crude oil as a supply source for U.S. refineries. Crude oil imports rose from 27% of U.S. refinery runs in 1985 to 61% in 2002. Due to this reliance on foreign crude oil, the relevant antitrust market in which the FTC assesses the likely competitive effects of mergers on crude oil supply ordinarily is global.

Market shares in crude oil can be measured by either production or reserves. Shares based on current production do not necessarily reflect a firm's ability to maintain its market position in the future at present prices or to expand output in response to higher prices. Some forces have led to increased competition in world crude oil markets since the early 1980s. The breakup of the former Soviet Union and the privatization of some state-owned oil companies, sometimes into multiple entities, have reduced concentration for world crude oil production and reserves. Crude oil production also has grown in regions – notably, the North Sea, China, Mexico, and some areas of Latin America, West Africa, and the Middle East – that are not members of the Organization of Petroleum Exporting Countries ("OPEC"). The development of more advanced spot and futures trading markets, mentioned above, has made prices more transparent and has facilitated bargaining by refiners.

OPEC[9] nevertheless continues to have a significant influence on world crude oil prices, even though coordination among its members to reduce output is imperfect. OPEC members in 2002 accounted for 38.5% of world crude oil production and 67.5% of world crude oil reserves. Saudi Arabia is OPEC's most important member. In 2002, Saudi Arabia accounted for about 11.6% of world crude oil production and about 21.6% of world crude oil reserves. (In contrast, ExxonMobil, the largest U.S. oil company, had only 1% of world crude oil reserves in 2002.) World crude oil reserves are more concentrated than crude oil production.

The share of world crude oil production accounted for by U.S.-based companies has declined from 11.4% in 1990 to 8.4% in 2002;[10] the share of these firms is even lower for world crude oil reserves. Recent large mergers among major oil companies have had little impact on concentration in world crude oil production and reserves. For example, Exxon and Mobil, which merged in 1999, had worldwide shares of crude oil production in 1998 of 2.1% and 1.3%, respectively; in 2002, the combined firm's share was 3.3%.[11] The BP/Amoco merger combined firms with world crude oil reserves of 0.7% and 0.2% in 1997; the combined firms'

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9 The ll members of OPEC are Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela.

10 These statistics represent the share of world production of U.S.-based companies listed on *Petroleum Intelligence Weekly*'s annual survey of the top 50 world producers.

11 In 2000, Shell, BP, and Chevron each had 3% or less of world production. Chevron is a U.S. firm; Shell and BP are non-U.S. firms.

world crude oil reserve share in 2002, which reflects the acquisition of ARCO in 2000 and the divestiture of ARCO's Alaska North Slope crude oil to Phillips, was 0.8%.

As the data above indicate, private oil companies have relatively small shares of world crude oil production and reserves, which limits their influence on world crude oil prices. Accordingly, the FTC has brought a merger enforcement action involving crude oil only when affected refiners had limited ability to shift among different crude types and the merger was likely to have a significant impact on production of the type of crude at issue.[12]

Several segments of this Report document how scale economies have assumed growing importance at many levels of the petroleum industry – a development that has lowered costs. Some of these scale economies relate to risk management in pursuit of crude oil supplies. In many cases, crude oil exploration and production ventures have become more risky as firms seek new sources of supply where extraction is more difficult and uncertain – such as the deep water Gulf Coast – or where there are difficult geopolitical issues – such as in the Caspian Basin. These risks have encouraged consolidation not only among major petroleum companies well known to consumers at the pump but also among large "independent" crude oil producers, such as Kerr-McGee and Devon.[13]

B. Bulk Transport of Crude Oil

The two primary methods of crude oil transportation are ocean tankers and pipelines. Crude oil tankers generally are used to import crude oil into the United States as well as to transport crude oil from Alaska to refineries in the lower 48 states. Concentration in the ownership of crude oil tankers is low, and mergers generally have not raised issues involving companies that own competing crude oil tankers. Nevertheless, statutory requirements that mandate the use of U.S. ships to carry crude oil on certain routes (requirements that also apply to marine shipments of refined petroleum products) can increase the price of crude oil transportation; these requirements have raised issues in one merger involving bulk crude transport on the West Coast.[14]

Pipelines are the ordinary means for moving crude oil from domestic fields or import centers to refineries. Crude oil pipelines exhibit economies of scale and require large sunk costs. Declining U.S. crude oil production has created excess capacity and caused many crude oil pipelines to close. Nevertheless, the crude oil pipeline infrastructure has undergone some notable additions. These include new gathering and trunk lines for Gulf of Mexico production and the opening in 1997 of the Express pipeline to bring Western Canadian crude oil to Montana and Wyoming, from which the crude can

[12] *See, e.g.,* BP/ARCO, Analysis to Aid Public Comment.

[13] Chapter 4 addresses the role of synergies in crude oil exploration and production as a motivation for mergers among major petroleum companies.

[14] The requirements and competitive consequences of the Jones Act are analyzed in Chapter 6. *See also* FTC Energy and Commerce Committee Statement, at 30-31, discussing how the Jones Act impacts the price of gasoline.

be transported to the upper Midwest on the Platte pipeline.

Tariffs and entry of crude oil pipelines generally remain highly regulated, and concentration in the ownership of crude oil pipelines at a national level is generally low. Despite these circumstances, crude oil pipelines may exercise market power at either end of the pipeline. Local crude oil producers may lack economical alternatives to pipelines (such as tanker, barge, rail, or truck transport) to ship their crude oil to refineries. Analogously, crude oil pipelines may have market power over refineries that lack economic alternatives for obtaining other crude oil supplies. Accordingly, as discussed below, the FTC in several merger cases has alleged relevant product markets for pipeline transportation of crude oil.

C. Refining

Refineries convert crude oil into finished products. Motor gasoline, distillate fuel (diesel fuel and home heating oil), and jet fuel accounted for 81% by volume of U.S. refinery finished products in 2002. These products sometimes are called "light petroleum products" ("LPPs").

Refineries are the heart of the system for bulk supply of refined petroleum products – that is, delivery of refined products to wholesale distribution terminals. A consuming area's bulk supply comes from either local refineries or more distant refineries that supply the market by pipeline, barge, or tanker. Bulk supply markets involve large quantities, often on the magnitude of hundreds of thousands of barrels per day.

Between 1973 and 1981, government controls on the pricing and allocation of crude oil favored small refineries and provided incentives for companies to own and operate small, inefficient refineries. The elimination of these government controls in 1981 spurred the eventual exit of many inefficient refineries. The number of domestic operable refineries declined from 216 in 1986 to 149 in 2004.[15] Refinery closures overwhelmingly have involved small, relatively unsophisticated facilities. Despite the trend toward fewer refineries with greater average size, there remains a wide range in capacities among operating refineries, with some still operating below minimum efficient scale.[16]

Increases in refinery productivity have come from developments that increase the complexity of the refining process. Technological change, in the form of increased computerization, greater use of advanced catalysts, additional processing units (such as catalytic crackers or alkylation plants) and advances in refining processes, enable refiners to obtain higher yields of lighter, more valuable refined products from any type of crude oil than before. Such measures also have allowed refiners to take advantage of economies of scale. Commonly used productivity yardsticks (such as those from the Bureau of Labor Statistics) tend to underestimate productivity gains in the refining sector, because they overlook

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[15] Total capacity has increased, however. *See* Chapter 7, Table 7-1, *infra*.

[16] Smaller refineries that have survived tend to have locational advantages and low-cost sources of crude oil.

the increased quality of gasoline resulting in cleaner air and other environmental benefits.

Since the mid-1980s, the average size and sophistication of U.S. refineries have increased. In 1986, about 24% of operating refineries had distillation capacity of more than 100,000 barrels of refined product per day; in 2004, the comparable figure was 42%.[17] Larger refineries tend to be more efficient than smaller refineries and can produce gasoline and other products at lower cost. Not only have individual refineries increased in size, but more companies are obtaining efficiencies by operating refinery networks. Refiners can thereby reduce costs through both large volume purchases of crude oil and consolidation of production of intermediate and refined products at particular refineries.

Many operating refineries have increased their capacity over the past two decades, but no U.S. refinery still in operation has been built since 1976. Given rising demand, it is not surprising that annual refinery capacity utilization rates have exceeded 90% since the mid-1990s. Due to capacity additions and reduced demand pressures, annual utilization rates in more recent years have dropped several percentage points from the 1998 peak level of 95.6%. Relatively high refinery capacity utilization rates ordinarily imply that refineries will have less supply available to send to areas in which refined product prices have risen suddenly due to a disruption in supply. Nonetheless, high utilization rates are not unprecedented. Refinery utilization rates during the first half of the 1950s and from 1963 to 1973 generally resembled recent rates.

The operations of and products produced by refineries have become subject to extensive environmental regulations during the past 20 years. The American Petroleum Institute ("API") estimates that refining accounted for about 53% of the petroleum industry's stated environmental expenditures of $98 billion (in current dollars) between 1992 and 2001. Regulations governing certain environmental characteristics of gasoline sometimes reduce substitutability among refiners' differing gasoline products, which can mean less ability to moderate price spikes through increased supply from other refineries. For example, relatively few refineries outside the West Coast can produce the type of gasoline currently required by the California Air Resources Board ("CARB"). The substantial investments needed to meet increasing environmental standards also tend to be more economical at larger refineries – another factor that has favored reliance on a smaller number of larger facilities.

D. Bulk Transport of Refined Petroleum Products

Refined products generally are shipped in bulk from refineries to storage terminals, from which they then are distributed by truck to local gasoline stations. These terminals often are located a considerable distance from the refineries. Pipelines and water (tankers and barges) are the principal means of shipment to bulk product terminals. Many refined product pipelines have

[17] In 1986, the average refinery had crude oil distillation capacity of 71.6 thousand barrels per day ("MBD"); in 2004, this average was 113.4 MBD. *See* Chapter 7, Table 7-1, *infra*; *see also* FTC Energy and Commerce Committee Statement, at 27-28.

recently expanded capacity, particularly those that carry products from the Gulf Coast to the Midwest and Mid-Continent.

The relative sizes of flows of refined products in the United States have not changed substantially in the last two decades. The Gulf Coast refining centers continue to produce the largest amount of refined product and to ship substantial volumes to the Midwest and the East Coast, which also may access foreign supplies of refined product. Shipments of refined products from the Gulf Coast to the Rocky Mountain area have begun to increase, and this trend is likely to continue as new pipeline projects and expansions come online. The West Coast, Alaska, and Hawaii remain relatively isolated and produce most of their own refined product. This isolation stems partly from the lack of pipeline connections with other regions of the United States and partly from the use – particularly in California – of mandated fuel formulations that are produced at only a limited number of refineries outside the West Coast.

E. Product Terminals and Gasoline Marketing

Terminals provide storage and dispensing facilities for bulk supply of refined products obtained from pipelines, tankers, barges, or adjacent refineries. "Proprietary" terminals are owned or operated by firms with refining or marketing activities. "Public" terminals are operated by pipeline companies or companies with no interests in refining or marketing. Census Bureau data at the state level from 1982 to 1997 show that the number of petroleum terminals fell from 2,293 in 1982 to 1,225 in 1997. Data from 1992 to 1997, however, show that, although the number of proprietary terminals continued to decline sharply, the number of public terminals increased by 10% nationally during that period.

According to a 1998 report of the National Petroleum Council, terminal closure and consolidation have been associated with a decline in terminal inventory holding since the 1980s. Improvements in supply management technologies, such as greater adoption of just-in-time inventory methods, contributed to a decline in inventories. The development of in-line terminal blending eliminated the need for storage of certain refined products, such as mid-grade gasoline, which now can be blended at the terminal from stocks of regular and premium grade gasolines. These changes have reduced the demand for terminal storage space, encouraged the closing of marginal terminals, and increased joint use of underutilized facilities through product exchanges and joint ventures.

Marketing stands immediately downstream from terminal services. Gasoline marketing includes wholesale and retail activities, including product branding, rack wholesale services, truck deliveries, and operation of service stations. Both brand-name companies and independent wholesalers (also known as "jobbers") have combined some operations to take advantage of economies of scale in gasoline marketing. Gasoline marketing now requires more investment in stations and distribution, as stations with convenience stores and many gasoline pumps have become the norm.

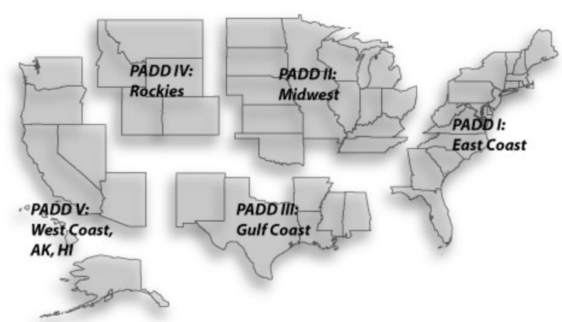
The development of "hypermarkets" has placed increased competitive pressure on existing gasoline outlets. Major retailers have begun to add gasoline islands to their retail outlets. These "hypermarkets" include mass-merchandisers such as Wal-Mart, club stores such as Costco, and supermarkets such as Kroger. Hypermarkets emerged as gasoline retailers during the late 1990s, captured more than 5% of U.S. gasoline sales in 5 years, and have become important sources of retail gasoline in some areas. Hypermarkets sell significant volumes of gasoline at prices lower than their competitors. In general, they can do this because they have lower costs associated with building and operating hypermarket sites, and they also may be willing to sell gasoline at smaller margins as part of a loss-leader or similar marketing strategy. Hypermarkets, together with the growth of independent gasoline marketers such as Sheetz and RaceTrac, have increased competition in gasoline marketing in some markets.[18]

The pursuit of scale economies has contributed significantly to change in the marketing of refined products. Substantial terminal consolidation has occurred, driven in part by changes in inventory practices. Consolidation has also occurred among wholesalers with the stated goal of achieving scale economies. For example, jobbers (independent wholesale distributors) have consolidated as gasoline marketing has become more capital-intensive, requiring larger investments in stations and distribution. Finally, average gasoline station volumes have increased over time. Stations with convenience stores and many gasoline pumps have replaced stations with service bays as the predominant form of retail outlet. As noted above, major retailers not previously engaged in the petroleum industry are adding gasoline islands at their outlets.

F. Trends in Flows of Crude Oil and Refined Products

Although crude oil imports have increased substantially and refined product imports have increased marginally (mostly to the East Coast), the relative significances of various crude oil and refined product flows within the United States has not changed substantially in the last two decades. Regional data on the petroleum industry are frequently based on Petroleum Administration for Defense Districts ("PADDs"). Figure 1-1 illustrates the regional contours of the five PADDs.

Figure 1-1
Petroleum Administration for Defense Districts



PADD III, which includes the Gulf Coast refining centers, continues to produce the largest amount of refined product and continues to ship substantial

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18 The FTC staff has provided comments on state legislation involving below-cost sales. This legislation appears to simply shield retailers from competition from more efficient firms. *See* FTC Energy and Commerce Committee Statement, at 31-32 and note 71.

volumes to the Midwest (PADD II) and the East Coast (PADD I). Shipments from the Gulf Coast to these areas have influenced the competitive analysis of mergers: refinery mergers in PADD I or PADD II are less likely to raise competitive concerns when customers can obtain product from multiple Gulf Coast sources and, in the case of PADD I, from imports. Use of mandatory fuel specifications in particular geographic areas has increased, however, and the sources of fuel supply to such areas may be more limited. In addition, because pipelines are frequently important sources of supply to these areas, mergers among pipelines or between refineries and pipelines may raise competitive concerns.

Shipments of refined products from PADD III to PADD IV (the Rocky Mountain area) have begun to increase, and this trend may continue if new pipeline projects and expansions are completed. PADD IV refineries are relatively isolated, and the FTC has taken enforcement actions against mergers that would have had a significant impact on bulk supply to some parts of this region.[19]

PADD V (the West Coast) continues to be relatively isolated, producing most of its own refined product. This isolation is due in part to the lack of significant pipeline connections with other parts of the United States and in part to the use – particularly in California – of special fuel formulations that are produced at only a limited number of refineries outside the West Coast. The limited supply alternatives for refined product, particularly for use in California, have affected the FTC's review of refinery mergers on the West Coast. The FTC has brought enforcement actions against several mergers that would have combined refining capacity on the West Coast, alleging that the mergers would have led to higher prices.

G. Vertical Integration in the Petroleum Industry

The increase in scale of operations in the petroleum industry has not been accompanied by an increase in vertical integration.[20] Rather, vertical integration between crude oil production and refining has tended to decline for the major oil companies. The incentives for vertical integration have diminished as refineries have become more flexible in the types of crude oil that they can process. The development of spot and future markets also has reduced the risks of acquiring crude oil through market transactions compared to relying upon vertical integration and intra-company transfers. Several significant refiners – including Valero/UDS, Sunoco, Tesoro, and Premcor – have no crude oil production, and integrated petroleum companies today tend to depend less on their own crude oil production.

Nationally, the share of gasoline distributed by jobbers increased from 55% to 61% between 1994 (the earliest year for which data are available) and 2002. Thus, refiners have sold an increasing share of gasoline at the terminal and a declining share at stations that they own or to which they deliver

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[19] *See, e.g.*, Conoco/Phillips, Analysis to Aid Public Comment.

[20] *See* the discussion at Chapter 9, note 22 *infra*, for a general discussion of the procompetitive efficiencies associated with vertical integration.

gasoline. The West Coast, where stations owned or supplied directly by refiners are predominant, is an exception. On the West Coast, the share of gasoline sold by stations that are owned or directly supplied by refiners increased somewhat in recent years, and terminal distribution by jobbers fell from 28% of volume in 1994 to 26.5% in 2002.

H. Competitive Consequences of Government Regulation

For over a century, various forms of government regulation have affected competition in the U.S. petroleum industry. Among the most important modern influences has been environmental regulation. Since the early 1970s, the petroleum industry has been subject to increasingly stringent environmental regulation, with many important requirements added during the 1980s and 1990s.[21] Key federal legislation includes the Clean Air Act; the Clean Water Act; the Oil Pollution Liability and Compensation Act; the Resource Conservation and Recovery Act; the Safe Drinking Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; and the Toxic Substances Control Act. State and local jurisdictions have additional environmental requirements that differ from federal standards. Among the regulations are requirements for cleaner burning fuels, controls on refinery air pollutants and water discharges, rules to prevent and clean up crude oil and product spills, requirements for collecting and handling solid wastes, and restrictions on fugitive emissions from transport and storage facilities.

These regulatory requirements affect market outcomes in important ways.[22] Fuel requirements that vary by geographic area, either for the whole year or seasonally, may impede the movement of refined product from one area to another in response to changes in relative prices. As a consequence, certain geographic areas may be more prone to price spikes in the event of a logistical problem (such as a refinery outage or a pipeline break).[23] Some market participants may choose not to make the investments needed to meet certain environmental mandates if returns are perceived to be insufficient; thus they will be unable to supply fuel to certain areas, because they do not meet the environmental fuel specifications. These regulations add directly to the cost of producing (and purchasing) gasoline as well.[24] As a result, regulations may influence the number of competitors in any market and, for any given competitor, the array of products it is

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[21] *See also* FTC Energy and Commerce Committee Statement, at 28-30.

[22] For a discussion of the effects of certain types of environmental regulation on competition, *see* Federal Trade Commission, *Study of Unique Gasoline Fuel Blends ("Boutique Fuels"), Effects on Fuel Supply and Distribution and Potential Improvements*, EPA 420-P-01-004, Public Docket No. A-2001-20, Comments of the Staff of the General Counsel, Bureaus of Competition and Economics, and the Midwest Region of the Federal Trade Commission Before the Environmental Protection Agency (Jan. 30, 2002).

[23] *See* FTC Energy and Commerce Committee Statement, at 28-30; Federal Trade Commission, *Final Report of the Federal Trade Commission: Midwest Gasoline Price Investigation* (Mar. 29, 2001) [hereinafter "Midwest Gasoline Report"].

[24] *See* FTC Energy and Commerce Committee Statement, at 28-30. That Statement also discusses other state laws and regulations that influence the price of gasoline (at 30-32).

willing and able to supply. As discussed in more detail in Chapter 2, such regulatory effects have important implications for antitrust enforcement.

IV. FTC Law Enforcement Activities in the Petroleum Industry

For more than 20 years, the FTC has been the federal antitrust agency primarily responsible for reviewing conduct in the petroleum industry to assess whether it is likely to reduce competition and harm consumer welfare. In this role, the FTC has devoted substantial resources to investigating and studying the industry. For example, during the period of large oil industry mergers in the late 1990s, the Bureau of Competition spent almost one-fourth of its enforcement budget on investigations in energy industries. The FTC has taken a strict approach in reviewing petroleum-related mergers and has obtained relief in markets at lower concentration levels than it has in other industries.[25] Although the FTC has expended most of its petroleum-related resources to investigate mergers, the agency also has devoted significant resources to non-merger matters, including investigations of gasoline prices in two regions of the United States, the Unocal case (discussed below), an ongoing program to monitor and investigate gasoline price anomalies, public conferences on factors that affect the price of refined petroleum products,[26] and industry studies such as this Report.

A. Merger Enforcement

The FTC has investigated every major petroleum industry merger in the past two decades and has brought enforcement actions against many of these mergers. Since 1981, the FTC has alleged that 15 large petroleum mergers would have resulted in significant reductions in competition and would have harmed consumers in one or more relevant markets had the mergers proceeded as announced. In 11 cases, the FTC obtained significant divestitures, including the sales of numerous refineries, pipelines, terminals and marketing assets to prevent reductions in competition and harm to consumers. In 4 other cases, the parties abandoned the mergers altogether after the FTC's antitrust challenge.[27]

The Commission has been especially concerned about potential

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25 *Compare* Federal Trade Commission, *Horizontal Merger Investigation Data, Fiscal Years 1996-2003* (Feb. 2, 2004), *with* Table 2-6, *infra*, Federal Trade Commission, Horizontal Merger Investigations – Post Merger HHI and Change in HHI (Delta) for Oil Markets, FY 1996 through FY 2003. These data show that the petroleum industry was the only industry in which the FTC sought relief in markets with post-merger HHIs below 2,000.

26 The Commission has held two public conferences (on August 1, 2001, and May 8-9, 2002) on factors that affect refined petroleum product prices. Participants in those conferences detailed the central factors that may affect the level and volatility of refined petroleum product prices. The staff of the FTC is likely to prepare a report on the topics discussed at those conferences. Federal Trade Commission, *FTC Chairman Opens Public Conference Citing New Model To Identify and Track Gasoline Price Spikes, Upcoming Reports* (press release) (May 8, 2002). Much of the learning presented at the conferences has been incorporated in this Report and in other work product of the Commission. *See generally* FTC Energy and Commerce Committee Statement, at 15-33 (detailing factors that affect the price of gasoline, and the gasoline price monitoring and investigation project), and other Commission work product discussed in that Statement.

27 For a summary of the relief required in the 15 matters, *see* Chapter 2, Figure 2-5, *infra*.

non-competitive behavior in the petroleum industry. In addition, a particular oil merger may involve a large number of relevant markets, and thus may require an extraordinary amount of time to ascertain whether anticompetitive effects are likely. Merging parties sometimes desire to settle competitive concerns quickly and avoid a lengthy investigation of a large number of relevant markets. In such instances, the FTC staff may adopt screens using HHI thresholds at levels low enough to assure that any plausible competitive concerns are remedied. In order to protect the public interest in competitive markets while accommodating those who desire to close quickly, the Commission has consistently required merger parties to bear the risk that relief might be over-inclusive, rather than imposing on the public the risk that relief might be under-inclusive.

Many transactions, particularly smaller ones, raised no competitive concerns and required no enforcement intervention.[28] As discussed throughout this Report, a case-by-case analysis is necessary to find the relevant markets in which competition might be lessened, to assess the likelihood and significance of possible competitive harm, and to fashion remedies to ensure that competition is not reduced in those relevant markets and consumers are not thereby harmed.[29]

The FTC's analysis of petroleum mergers follows the same DOJ/FTC Horizontal Merger Guidelines[30] that the agencies use to analyze mergers in other industries. Although the basic tenets of the Merger Guidelines remain the same as when they were issued in 1982,[31] the analysis has become more sophisticated over the years. Consistent with advances in economic learning and case law developments, while merger analysis begins with concentration data, emphasis is placed on qualitative factors that indicate whether a merger will

[28] *See* discussion in FTC Energy and Commerce Committee Statement, at note 14.

[29] In May 2004, the General Accounting Office (now the Government Accountability Office) released a report that purported to analyze how eight petroleum industry mergers or joint ventures carried out during the mid-to-late 1990s affected gasoline prices. U.S. General Accounting Office, *Energy Markets: Effects of Mergers and Market Concentration in the U.S. Petroleum Industry* (May 2004). The Commission regards evaluations of past enforcement decisions as valuable elements of responsible antitrust policymaking, and is supportive of the goal of the GAO inquiry – to evaluate the consequences of past decisions by the federal antitrust agencies. However, the Commission believes the GAO report is "fundamentally flawed" and suffers from "major methodological mistakes that make its quantitative analysis wholly unreliable." For example, the GAO's models did not properly control for the numerous factors that cause gasoline prices to increase or decrease; the report failed to measure concentration in any properly defined geographic market; and the report failed to consider critical facts about the individual mergers it studied. These mistakes and omissions significantly undermine any results of the GAO study, deny the GAO report any validity in assessing the effect of concentration on prices, and render its results suspect. *See* FTC Energy and Commerce Committee Statement, at 7-10, and the appendix attached to that Statement.

[30] United States Dep't of Justice and Federal Trade Comm'n, *1992 Horizontal Merger Guidelines (with April 8, 1997, Revisions to Section 4 on Efficiencies*), *reprinted in* 4 Trade Reg. Rep. (CCH) ¶13,104 [hereinafter "Merger Guidelines"].

[31] The Department of Justice first issued Merger Guidelines in 1968. United States Dep't of Justice, *Merger Guidelines* (1968), *reprinted in* 4 Trade Reg. Rep. (CCH) ¶13,101. By the late 1970s, case law and economic learning had largely overtaken the analytic framework of those Guidelines. The current analytic framework of the Guidelines derives from the learning encompassed in the 1982 Merger Guidelines. *See* Thomas B. Leary, *The Essential Stability of Merger Policy in the United States*, 70 ANTITRUST L. J. 105 (2002).

increase the ability of the merging parties to exercise market power by curbing output unilaterally or by coordinating their behavior with rival suppliers.[32]

The Commission's application of the Merger Guidelines to petroleum mergers generally has served to prevent increased concentration in properly defined relevant antitrust markets. The nation, PADDs, or states rarely correspond to relevant markets for purposes of antitrust analysis, and the definition of a relevant market is specific to the anticompetitive concerns associated with a particular merger. The identification of relevant geographic markets requires detailed, fact-intensive inquiries, and such inquiries for the numerous levels of the industry and areas of the country are beyond the scope of this Report.

Nevertheless, information on national, PADD, and state concentration can contribute to an understanding of broad industry trends. When possible, the Report provides information for what may be relevant antitrust markets, and reviews concentration in areas that were highlighted in previous reports.

Substantial industry restructuring and consolidation have occurred in the last two decades. Despite increases in concentration at some production levels over that period, particularly since the mid-1990s, most sectors of the petroleum industry at the national, regional, or state level generally remain unconcentrated or moderately concentrated. Refining concentration in PADDs II through V, as measured by the HHI, remains under 1,400. While concentration for refining in PADD I has increased above this level, this concentration measurement does not take into account competition from Gulf Coast shipments and imports. Wholesale and retail concentration at the state level remains unconcentrated or moderately concentrated in most cases, that is, below 1,800. In addition, the growth of independent marketers such as Sheetz and RaceTrac and hypermarkets such as Wal-Mart and Costco has increased competition at the wholesale and retail levels in many areas.

Some increased concentration is due to mergers. An increase in concentration from a merger, however, is not sufficient to find that a merger was anticompetitive. Where concentration changes raise concerns about potential competitive harm, the FTC conducts more detailed investigations.[33] The FTC has required divestitures or sought preliminary injunctions when it has concluded that a merger is likely to reduce competition. Many of the mergers the FTC challenged would have raised concentration significantly if they had proceeded as originally planned.

In those cases resolved by selective divestitures, rather than challenges to the entire merger, only parts of the merger raised competitive concerns. Nevertheless, some

[32] Unilateral effects occur when the merged firm profitably reduces its own supply and raises prices, even though other competitors may respond by increasing their own output. Such behavior can be profitable if the merged firm has a significant share of sales and the response of competitors is limited. Coordinated behavior occurs when the firms remaining in the market coordinate a reduction in output and an increase in prices, with each firm reducing its output.

[33] Threshold concentration levels are discussed in Chapter 2, *infra*.

divestitures have been massive. For example, ExxonMobil was required to divest the entire Northeast and Mid-Atlantic marketing operations of one of the two parties, in addition to other assets. Sometimes assets not directly involved in the market of competitive concern must be divested to assure the viability of the divested assets. For instance, a refinery divestiture may require sale of downstream terminal and marketing assets. In most cases, the FTC has secured the necessary relief to prevent competitive harm through consent agreements. In a few cases, however, there was no agreement, leading the FTC to seek a preliminary injunction to enjoin the merger pending a fuller administrative hearing to resolve the disputed competitive issues. These transactions ultimately were not consummated as originally structured; the parties either abandoned them after the FTC went to court, or agreed to a consent order after litigation was initiated.[34]

Mergers have raised competitive concerns at all the various levels of the petroleum industry, but the majority of actions have involved downstream activities, *i.e.*, refining, refined products pipelines, terminals and marketing. The competitive concern generally has been that the merger would enable the merged firm to raise prices in a market for products that it sells to the next level of the industry (*e.g.*, refined products sold to wholesalers, or wholesale products sold to retailers) through either unilateral or coordinated behavior. A key element in assessing the potential for adverse competitive effects is determining the alternatives available to customers, including whether more distant suppliers are viable options. In a few cases, enforcement actions were based on competitive problems involving monopsony, potential competition, or vertical concerns relating to raising rivals' costs.

In sum, mergers have contributed to the restructuring of the petroleum industry in the past two decades but have had only a limited impact on industry concentration. The FTC has investigated all major petroleum mergers and required relief when it had reason to believe that a merger was likely to lead to competitive harm. The FTC has required divestitures in moderately concentrated markets, as well as highly concentrated markets. By studying industry trends, including merger and FTC enforcement activity at key levels of the petroleum industry, this Report should further understanding of the petroleum industry and the factors that influence prices and other market outcomes in the industry.

B. Non-Merger Enforcement

The FTC has devoted substantial resources to investigating alleged anticompetitive conduct, gasoline price differentials, and rapid price increases, and to monitoring gasoline prices.

[34] The transactions where the parties entered into, or were subject to, an order after litigation was initiated were PRI/Shell and BP/ARCO. In PRI/Shell, the district court granted the FTC's request for a preliminary injunction and the parties abandoned that transaction (in November 1987). However, the Commission later issued an administrative complaint against PRI and eventually entered an order requiring PRI to get prior approval of future acquisitions. *Pacific Resources, Inc.*, 111 F.T.C. 322 (1988). In BP/ARCO, the parties entered into an order that addressed the Commission's concerns prior to trial.

1. *Unocal Litigation*

In March 2003, the Commission issued an administrative complaint alleging that Union Oil Company of California ("Unocal") violated Section 5 of the FTC Act by subverting the California Air Resources Board's ("CARB") regulatory standard-setting procedures relating to low-emissions reformulated gasoline ("RFG").[35] According to the complaint, Unocal misrepresented to both CARB and industry participants that some of its emissions research was non-proprietary and in the public domain, while at the same time pursuing a patent that would permit Unocal to charge royalties if CARB used such emissions information. The complaint alleges that Unocal did not disclose its pending patent claims and that it intentionally perpetuated the false and misleading impression that it would not enforce any proprietary interests in its emissions research results. The complaint states that Unocal's conduct allowed it to acquire monopoly power over the technology used to produce and supply California "summer-time" RFG, a low-emissions fuel mandated for sale in California from March through October, and could cost California consumers 5 cents per gallon in higher gasoline prices. This case was originally dismissed by an Administrative Law Judge, but the Commission has reversed the decision, reinstated the complaint, and remanded the case for a full trial.[36]

[35] *Union Oil Company of California*, Docket No. 9305 (Complaint) (Mar. 3, 2003).

[36] *Union Oil Company of California*, Docket No. 9305 (Opinion of the Commission) (July 6, 2004).

2. *Gasoline Price Monitoring*

In May 2002, the FTC announced a project to monitor gasoline prices to identify "unusual" movements in prices and then examine whether any such movements might result from anticompetitive conduct that violated Section 5 of the FTC Act.[37] This project tracks retail gasoline prices in approximately 360 cities nationwide and wholesale (terminal rack) prices in 20 major urban areas. FTC Bureau of Economics staff receives daily data purchased from the Oil Price Information Service ("OPIS"), a private data collection company. FTC economists use statistical models to determine whether retail and wholesale prices are anomalous in comparison with historical data. These models rely on current and historical price relationships across cities, as well as other variables. Prices outside the normal bounds trigger further staff inquiry to determine what factors might be causing price anomalies in a given area. These factors could include supply disruptions such as refinery or pipeline outages, changes in taxes or fuel specifications, unusual changes in demand due to weather conditions and other causes, and possible anticompetitive activity.[38]

[37] Federal Trade Commission, *FTC Chairman Opens Public Conference Citing New Model To Identify and Track Gasoline Price Spikes, Upcoming Reports* (press release) (May 8, 2002).

[38] The monitoring program is discussed in more detail in the FTC Energy and Commerce Committee Statement, at 15-24, which describes particular examples of recent price changes and their likely causes.

3. *Western States Gasoline Pricing Investigation*

In response to concerns that differences in the prices of gasoline in San Francisco, Los Angeles, and San Diego might be in part a result of anticompetitive conduct, in 1998 the FTC opened an investigation into gasoline marketing and distribution practices employed by the major oil refiners in Arizona, California, Nevada, Oregon, and Washington. The FTC completed its investigation in 2001.[39] That investigation provided no basis to allege a violation of the antitrust laws. The investigation uncovered no evidence of horizontal agreements on price or output or on the adoption of any vertical distribution practice at any level of supply. Also, the investigation uncovered no evidence that any refiner had the unilateral ability profitably to raise prices or to reduce output at the wholesale level in any market.[40]

4. *Midwest Gasoline Price Investigation*

The FTC conducted an investigation of a spike in RFG prices in several Midwest states in the spring and early summer of 2000. The FTC found no credible evidence of collusion or other anticompetitive conduct by the oil industry leading up to, or during, price spikes in the Midwest. In its March 2001 report on the investigation, the FTC concluded that a number of structural and operating factors appeared to have caused the spike, including high refinery capacity utilization, pipeline disruptions, low inventory levels, and the use of ethanol as an oxygenate, as well as unexpected occurrences (such as pipeline breaks and production difficulties) and errors by refiners in forecasting industry supply or reacting to the event.[41]

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[39] Western States Gasoline Pricing, File No. 981-0187; *see FTC Closes Western States Gasoline Investigation* (press release) (May 7, 2001). For a later review of what factors affect gasoline prices on the West Coast, *see* EIA, *2003 California Gasoline Price Study Final Report* (Nov. 2003); California Energy Commission, *Causes for Gasoline & Diesel Price Increases in California* (Mar. 2, 2003); *see also* Christopher Taylor & Jeffrey Fischer, *A Review of West Coast Gasoline Pricing and the Impact of Regulations*, 10 INT'L J. ECON. BUS. 225 (2003).

[40] As part of this investigation, the FTC examined distribution practices known as “zone pricing” and “redlining.” These practices, and their potential competitive effects and justifications, are discussed in greater detail *infra*, at Chapter 9, note17.

[41] Midwest Gasoline Report. The industry responded to the price spike within three to four weeks with increased supply of products. The total length of the spike was less than two months. By mid-July 2000, prices had receded to pre-spike or even lower levels. *See also* EIA, *Supply of Chicago/Milwaukee Gasoline Spring 2000*; Jeremy Bulow, et al., *U.S. Midwest Gasoline Pricing and the Spring 2000 Price Spike*, 24 ENERGY J. 21 (2003); Remarks of Jeremy Bulow, Director, Federal Trade Commission Bureau of Economics, *The Midwest Gasoline Investigation* (Apr. 17, 2001).

Chapter 2

Federal Antitrust Enforcement: Mergers in Petroleum-Related Markets

I. Introduction and Background

Merger enforcement helps preserve rivalry that brings lower prices and better services to consumers. As a market becomes more concentrated, it may become easier for firms to coordinate their pricing or output decisions. Also, a single firm with a large market share in a highly concentrated market may exercise market power unilaterally.

The FTC has reviewed every significant petroleum industry merger since 1981. During that time, the FTC has taken enforcement action against 15 major petroleum mergers that likely would have resulted in significant reductions in competition in one or more relevant markets, had the transactions proceeded as originally announced. When the FTC has challenged a transaction, its goal has been to maintain the pre-merger level of competition in those markets. To accomplish this, in 11 matters the Commission required divestitures of significant assets, including interests in 15 refineries and numerous, substantial interests in pipelines, terminals, and marketing assets. Those divestitures transferred the assets to firms that would maintain competition post-merger. In 4 other cases, the mergers were either abandoned or blocked following Commission or court action.[1]

A review of data on all of the FTC's horizontal merger investigations and enforcement actions from 1996 to 2003 reveals that, for mergers involving petroleum products, the FTC has obtained relief in both moderately and highly concentrated markets, as defined in the Merger Guidelines.[2]

Many mergers involving petroleum products do not violate the antitrust laws. In some petroleum-related mergers, the merging companies do not compete in the same relevant markets. In other cases, while the merging companies compete in one or more relevant markets, their market

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[1] Two mergers were abandoned: Gulf/Cities Service and Conoco/Asamera. A third, PRI/Shell, was enjoined by a district court. In the remaining case, Mobil/Marathon, the FTC sought a preliminary injunction, but the transaction was abandoned following the result of private antitrust litigation. *See Marathon Oil v. Mobil Corp.*, 530 F. Supp. 315 (N.D. Ohio), *aff'd*, 669 F.2d 378 (6th Cir. 1981).

Some transactions are abandoned voluntarily after an antitrust investigation is begun but before formal enforcement action is taken; these transactions are not included in the count of 15. For example, Shell abandoned its proposed acquisition of Exxon marketing assets in Guam as the FTC was preparing to challenge the transaction. *See* William J. Baer, Director, Bureau of Competition, Statement of the Federal Trade Commission, Before the Subcommittee on Energy and Power, Committee on Commerce, U.S. House of Representatives (Mar. 10, 1999).

[2] *See* Table 2-6. In the absence of government regulation, high concentration is a necessary, but not sufficient, condition for anticompetitive effects.

shares are sufficiently low that an attempt to increase price would be defeated by likely responses from actual or potential competitors (such as an increase in supply, or the repositioning of a competing product or a close substitute), or by consumers' switching their purchases to competing firms. Alternatively, the industry dynamics may be such that a merger will not increase the remaining firms' ability or incentive to coordinate pricing or output decisions. For example, a merger among firms operating in the same market may be procompetitive by enhancing the combined firm's ability to compete with the remaining firms or by reducing its incentive to coordinate with another firm's price or output decisions. Such cases do not warrant FTC enforcement action, because competitive harm is unlikely to occur.[3]

In petroleum-related matters – as with all transactions that merit antitrust scrutiny – the FTC bases its enforcement decisions on extensive staff investigations, including reviews of documents from the merging parties, interviews of customers and competitors in the relevant markets, and other facts and analysis.[4] The agency staff typically reviews thousands of documents and talks with numerous market participants as it evaluates likely competitive effects from a merger or acquisition. Before any final determination is made, the Commission reviews staff work and white papers from the parties, and Commissioners meet with representatives of the merging parties. Literally hundreds of thousands of hours of staff and Commission time have been devoted to the evaluation of proposed petroleum mergers, acquisitions, and joint ventures since the FTC first challenged a petroleum merger in 1981.[5] Indeed, during the period of large oil industry mergers in the late 1990s, the Bureau of Competition spent almost one-fourth of its enforcement budget on investigations in the energy industries.

The FTC's enforcement record reflects the ebb and flow of merger activity by petroleum companies. As explained in Chapter 4, since the large mergers of 1984, there have been three distinct periods of merger activity by leading petroleum companies.[6] In the first period, from 1985 to 1990, leading petroleum companies acquired somewhat more assets than they divested. The second period, from 1991 through 1996, saw less overall merger activity, with leading petroleum companies divesting more assets than

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[3] Mergers for which the FTC did not require relief include Sun/Chevron (1994), ARCO/Thrifty (1997), Tosco/Unocal (1997), Marathon/Ashland (1998), Marathon Ashland/UDS (1999), Phillips/Tosco (2001), and Sunoco/Coastal Eagle Point (2004).

[4] If a transaction presents a possible competitive problem, the FTC issues "second requests" under the Hart-Scott-Rodino ("HSR") Act (or subpoenas if no HSR filing was made) to obtain the information necessary to undertake a careful, detailed review. "Model" second requests have been released by the FTC; these documents illustrate the type and scope of information requested in a merger investigation. *See* Model Request for Additional Information and Documentary Material (Second Request), *available at* http://www.ftc.gov/bc/hsr/introguides/guide3.pdf, and Model Retail Request for Additional Information and Documentary Material, *available at* http://www.ftc.gov/os/2004/04/040428modelrequest.pdf. Actual second requests issued in a merger investigation will differ from the models; differences may depend on many factors, such as the industry, specific concerns raised by a transaction, the type of data known to be available, and experience gained from other investigations. *See FTC, Announced Action for April 28, 2004* (press release).

[5] Mobil/Marathon.

[6] The appendix to Chapter 4 describes the definition of "leading petroleum companies" in detail.

they acquired by a substantial margin.[7] The final period, from 1997 to 2001, was characterized by an extraordinary burst of merger activity. A review of Table 2-5, which shows all of the FTC's enforcement actions involving petroleum mergers from 1981 through 2002, reveals that the FTC's enforcement record is in line with these general market observations. Between 1985 and 1990, the FTC challenged 3 petroleum mergers (involving 12 relevant markets) as likely to result in a substantial lessening of competition. The FTC challenged no petroleum mergers from 1991 to 1996. From 1997 through 2001, the FTC challenged 6 petroleum mergers as likely to have anticompetitive effects in one or more relevant markets. The Commission challenged 2 more major petroleum mergers in 2002. For these 8 most recent matters, the total number of relevant markets in which competitive effects were alleged exceeded 200.

II. Merger Enforcement

A. Overview of Merger Analysis

Section 7 of the Clayton Act prohibits acquisitions that may tend substantially to lessen competition.[8] To determine whether an acquisition is likely to have that effect, the FTC uses the methodology described in the Horizontal Merger Guidelines. The unifying theme of the Guidelines is that "mergers should not be permitted to create or enhance market power or to facilitate its exercise."[9]

The basic framework of analysis applied to petroleum and other mergers has remained the same since 1982.[10] This framework requires, at first, the definition of the relevant product and geographic markets in which, post-merger, a hypothetical monopolist profitably would impose at least a "small but significant and nontransitory increase in price" ("SSNIP"). Once the relevant markets are defined, the agency staff measures market shares and concentration in those markets. The staff then assesses whether and how the merger might create or facilitate the exercise of market power in those markets. The analysis continues with an evaluation of whether new entry would be timely, likely, and sufficient to counteract any anticompetitive effects, and whether cognizable efficiencies are of a character and magnitude such that the merger is not likely to be anticompetitive in any relevant market.[11] The remainder of Section II explains this methodology and its application to the petroleum industry.

B. Relevant Markets

One of the first questions in merger analysis is whether the merging parties compete in one or more relevant antitrust markets in the United States. A relevant antitrust market includes both a

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7 Merger activity in the petroleum industry from the mid-1980s until the second half of the 1990s generally involved relatively small asset acquisitions. As a result, FTC petroleum merger enforcement actions during this time generally involved small acquisitions, alleged to reduce competition in a limited number of local markets.

8 15 U.S.C. § 18.

9 Merger Guidelines, § 0.1.

10 Thomas B. Leary, *The Essential Stability of Merger Policy in the United States*, 70 ANTITRUST L.J. 105, 107 (2002) ("the core principles of merger policy have remained stable for the last twenty years").

11 The agency also will consider failing firm defenses, *see* Merger Guidelines, § 5, but such defenses have not played any significant role in petroleum-related mergers.

product and a geographic area – *e.g.*, the marketing of gasoline in five metropolitan areas in Texas.[12] Relevant product markets in petroleum mergers generally have been based on one or more closely related stages in the process of transforming crude oil into refined products. These stages include: 1) exploration and production of crude oil; 2) bulk transportation of crude oil; 3) bulk supply (refining and bulk transportation) of refined products; 4) terminaling of refined products; and 5) marketing (wholesaling and retailing) of refined products. Product markets also may be more narrowly defined for specific types of crude oil or refined products, such as the bulk supply of gasoline compliant with CARB specifications. Geographic markets can vary from worldwide to local markets. Large petroleum mergers often involve many relevant markets, some of which raise competitive concerns and some which do not.

1. *"Hypothetical Monopolist" Test*

To define a relevant antitrust market, the Merger Guidelines apply a "hypothetical monopolist" test. That test asks whether a hypothetical, profit-maximizing monopolist of a group of products in a certain geographic area likely would impose at least a SSNIP. The Merger Guidelines suggest asking the question using a 5% SSNIP – that is, asking whether a nontransitory price increase of 5% or more would be profitable for a hypothetical monopolist (*i.e.*, would not result in sufficient consumers switching to other products, or to the same product produced by firms at other locations). Nonetheless, the Merger Guidelines explicitly recognize that "the nature of the industry" may lead enforcement agencies to use some other, more appropriate price standard. The FTC staff frequently has used a one-cent-per-gallon price increase in defining relevant markets for petroleum mergers. This standard reflects a price increase of less than 5% when based on recent values of petroleum products.[13] In effect, this test identifies what products in which geographic locations constrain the price of one of the products of one of the merging firms.

2. *Product Market Definition*

Beginning with each product of each of the merging firms and sequentially broadening the group of products by adding next-best substitutes, a relevant product market emerges as the

[12] *See* Exxon/Mobil, Complaint ¶ 33.

[13] The standard is justified on two grounds. First, a one-cent-per-gallon price increase is significant in this industry, much of which is characterized by large volumes and thin margins. Net refinery margins, for example, historically have been on the order of several cents per gallon. Price differences of one cent (or even less) can affect production decisions or the allocation of product across geographic areas. Second, a one-cent-per-gallon standard is an appropriate compromise when refineries and product pipelines are competing sources of supply for refined products. (For example, in Conoco/Phillips, the FTC alleged that the proposed merger would harm competition to supply light petroleum products in bulk in northern Utah, where purchasers could obtain such bulk supply from refineries (one of which was owned by Phillips) or from a product pipeline in which Conoco held a 50% undivided ownership interest. Complaint ¶¶ 26-30.) In a merger of petroleum product pipelines only, the relevant price would be the transportation tariff. Merger Guidelines, § 1.11, note 11. Transportation tariffs are typically on the order of 2 to 3 cents per gallon, implying a 5% SSNIP of between 0.1 and 0.15 cents per gallon. By contrast, for a merger of competing refineries, a 5% SSNIP would be between 2.5 and 6 cents per gallon, because the wholesale price charged for refined products at the refinery gate in recent years has varied between $.50 and a $1.20 per gallon. When competition between pipelines and refineries is of interest, the one-cent-per-gallon rule represents a middle ground.

smallest group of products that satisfies the hypothetical monopolist test. Product market definition depends critically upon demand-side substitution between and among the products of the merging firms and products sold by other firms. For many types of refined petroleum products, such as gasoline, there generally are wide gaps in the chain of substitution, making product market definition relatively straightforward (for example, one cannot substitute jet fuel for ordinary gasoline). If competitive and other supply conditions across various products generally are comparable, antitrust analysts may use a larger grouping (*e.g.*, a "light petroleum products" market consisting of gasoline and middle distillates).

3. Geographic Market Definition

Analogously, beginning with each location of each of the merging firms for a given product, a relevant geographic market is the smallest group of locations that satisfies the hypothetical monopolist test. The key question in defining relevant geographic markets is to what locations buyers would turn in response to a SSNIP. For example, if a merger would combine the ownership of two product terminals that are close to each other, geographic market definition would focus on the extent to which customers (*e.g.*, jobbers) would send trucks to more distant terminals in response to higher rack prices at the merging terminals. The costs of transportation from, and the rack prices and potential capacity limitations at, those more distant terminals would be relevant in determining the extent of the geographic market.

Similarly, for a merger combining the ownership of two nearby refineries, to delineate relevant geographic markets for bulk supply of refined products, the FTC would need to identify other sources of supply to which buyers in the area would turn in response to a hypothetical price increase. Historical data or other evidence might indicate that, in response to a hypothetical price increase, buyers would obtain additional supplies transported by pipelines, tankers, or barges from more distant refineries. If these additional sources of supply would be sufficient to defeat an anticompetitive price increase by refineries in the area, the result would be to expand the geographic market and/or to increase the number of suppliers in the market.

Whether more distant refineries should be included in the market depends on a variety of factors. These factors include the costs of transportation from more distant refineries, as well as capacity limitations at those refineries. Capacity or access limitations at the bulk transportation or terminal levels are also relevant. For instance, in Conoco/Phillips, the FTC excluded from the relevant market – bulk supply of light petroleum products (from refineries or pipelines) to eastern Colorado – "other sources of bulk supply to Eastern Colorado [that] are already largely at capacity (products pipelines and local refineries)."[14] The staff also considers existing vertical relationships that, among other things, might impede more distant suppliers from securing distribution outlets. For example, in Shell/Texaco, the FTC alleged that "[s]ix vertically integrated

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[14] Conoco/Phillips, Analysis to Aid Public Comment.

oil companies control approximately 90% of the gasoline sold at both wholesale and retail in San Diego County. These oil companies require[d] their branded retailers to buy gasoline at San Diego terminals," so purchasers could not turn to terminals in Los Angeles if prices rose at terminals in San Diego. Thus, prices in San Diego were not constrained by sales from terminals in Los Angeles.[15] Another relevant factor is the opportunity cost of diverting product from one sales destination to another. For instance, in Conoco/Phillips the FTC excluded from one of the relevant geographic markets "suppliers [that] have no economic incentive to divert light petroleum products from more lucrative areas in the Rockies to Eastern Colorado."[16]

4. Price Discrimination Markets

Finally, the Merger Guidelines address how to define relevant markets where a hypothetical monopolist would find it profitable to practice price discrimination – that is, to charge different prices to different buyers for the same product, without a difference in costs. (Relevant markets may be narrower if different customers can be charged different prices.[17]) In 2000, the FTC's complaint in BP/ARCO alleged that the combination of BP's and ARCO's holdings of Alaska North Slope ("ANS") crude oil would reduce competition in three relevant markets. One of the markets (sale of ANS crude to "targeted" West Coast refineries) involved a price discrimination market definition predicated on the technological constraints of certain West Coast refineries in shifting away from higher-priced ANS crude toward foreign or other domestic crudes, and on the costliness of arbitrage that otherwise might prevent price discrimination among refineries for ANS crude.[18]

C. Market Shares and Concentration

Once the staff defines the relevant markets, it estimates market shares and concentration for each market. Market share and market concentration data in properly defined markets are useful indicators of the likely potential competitive effect of a merger.[19] The Merger Guidelines explain:

> Other things being equal, market concentration affects the likelihood that one firm, or a small group of firms, could successfully exercise market power. The smaller the percentage of total supply that a firm controls, the more severely it must restrict its own output in order to produce a given price increase, and the less likely it is that an output restriction will be profitable. If collective action is necessary for the exercise of market power, as the number of firms necessary to control a given percentage of total supply decreases, the difficulties and costs of reaching and enforcing an understanding [among firms] with

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15 Shell/Texaco, Analysis to Aid Public Comment.

16 Conoco/Phillips, Analysis to Aid Public Comment.

17 "Competition for sales to each such group may be affected differently by a particular merger and markets are delineated by evaluating the demand response of each such buyer group." Merger Guidelines, § 1.0.

18 BP/ARCO, Analysis to Aid Public Comment.

19 Merger Guidelines, § 1.151.

respect to the control of that supply might be reduced.[20]

Nonetheless, certain points should be noted with respect to concentration measures.

1. *The Competitive Significance of Market Shares and Market Concentration*

Market share and concentration data are important.[21] However, they provide only the starting point for analyzing the competitive impact of a merger.[22] In accord with the Guidelines, the FTC assesses many additional market factors before determining whether to challenge a merger. Over time, as the economic analysis of mergers has become more sophisticated and the agencies have discovered through experience that market structure is sometimes not the best indicator of market performance, calculations of concentration have become less significant.[23]

The competitive significance of market shares and concentration can be assessed only in properly defined antitrust markets. If a market is defined too broadly or too narrowly, market shares and concentration may understate or overstate the true competitive circumstances. For example, consider a merger in which each of the merging parties has a refinery within 1,000 miles of the other's refinery. If those two refineries compete with one another in the supply of certain refined products to particular geographic locations, defining too narrow a geographic market – that is, a geographic market that includes only one of the refineries – could lead the agency mistakenly to overlook a competitive overlap that would increase market share and concentration. On the other hand, if those two refineries do not compete with each other, defining the geographic market too broadly to include both refineries would overstate the true market shares and concentration.

Concentration or market share estimates tied to PADDs or states generally cannot be used to assess the likely competitive effects of a merger. Data limited to those geographic areas may exclude facilities that do compete with each other, thus potentially understating concentration levels, and also may include facilities that do not compete with each other, thus overstating concentration levels. Although such data can be suggestive of general industry trends – especially when viewed in the context of other industry information – they are generally not accurate indicators of competitive conditions.

2. *Measures of Market Share and Concentration*

a. Market Shares

The agency normally will calculate market shares for all firms identified as market participants "based

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20 Merger Guidelines, § 2.0.

21 *Id.*

22 *Id.*

23 Leary, *supra* note 10, 70 ANTITRUST L. J. at 116-17; *U.S. v. General Dynamics Corp.*, 415 U.S. 486 (1974). *See generally* Timothy J. Muris, Chairman, Federal Trade Commission, *How History Informs Practice – Understanding the Development of Modern U.S. Competition Policy* (Nov. 19, 2003) (discussing evolution of the Merger Guidelines' diminished emphasis on concentration statistics for determining likely anticompetitive effects). A recent study by three FTC economists found that "the HHI thresholds in the Guidelines, alone, have generally not been determinative in enforcement decisions." David T. Scheffman, Malcolm Coate & Louis Silvia, *20 Years of Merger Guidelines Enforcement at the FTC: An Economic Perspective*, 71 ANTITRUST L. J. 277, 300 (2003).

on the total sales or capacity currently devoted to the relevant market together with that which likely would be devoted to the relevant market in response to a 'small but significant and nontransitory' price increase."[24] Market shares "can be expressed either in dollar terms through measurement of sales, shipments, or production, or in physical terms through measurement of sales, shipments, production, capacity, or reserves."[25]

Identifying all of the participants in a relevant market requires careful analysis. For example, refiners that currently do not produce a given fuel or a given fuel specification may be able to do so relatively quickly and with relatively little expense. In such cases, they will be treated as market participants under the Merger Guidelines, because they likely would enter the relevant market if prices rose post-merger, and their supply response would deter anticompetitive price increases.[26]

b. Market Concentration

As noted earlier, the Merger Guidelines use a measure of concentration known as the Herfindahl-Hirschman Index ("HHI"), which equals the sum of the squared market shares of all market participants. For a given number of firms, the HHI is higher the more unequal are the market shares. For example, a market with five equal-sized firms, each with a share of 20%, has an HHI of 2,000.[27] However, if four of the five firms have market shares of 15% each, while the fifth has a market share of 40%, the HHI is 2,500.

Any merger that reduces the number of competing firms causes the HHI to increase. The increase is greater the larger the market shares of the merging firms. In the preceding example, if two of the firms with shares of 15% merge, the HHI increases by 450. However, if a firm with a share of 15% merges with the firm that has a 40% share, the HHI increases by 1,200.[28]

The Merger Guidelines categorize market concentration, as measured by HHI, into three concentration zones. First, there is an "unconcentrated" zone with an HHI below 1,000, where the agency would be unlikely to challenge a merger. Then there is a "moderately concentrated" range with an HHI between 1,000 and 1,800, where a merger resulting in an increase of 100 "potentially raises significant competitive concerns." Finally, there is a "highly concentrated" zone with an HHI over 1,800. In this zone, a merger resulting in an HHI increase of 50 "potentially raises significant concerns" and, for a merger resulting in an HHI increase of 100, there is a rebuttable presumption that it "create[s] or enhance[s] market power,

24 Merger Guidelines, § 1.41.

25 *Id.*

26 In Merger Guidelines terminology, such market participants are labeled "uncommitted entrants." *See* Merger Guidelines, § 1.32.

27 The HHI in a market with (n) equal-sized sellers is equal to 10,000/(n). A market with ten equal-sized sellers has an HHI of 1,000, and a market with six equal-sized sellers has an HHI of 1,667.

28 For the purpose of the post-merger HHI calculation, market participants' shares are assumed to remain unchanged after the merger. The merged firm's share is simply the sum of the pre-merger shares of the merging firms; this yields an assumed change in the HHI of twice the product of the shares of the merging firms.

or facilitate[s] its exercise." This presumption may be overcome by showing that factors set forth elsewhere in the Merger Guidelines make it unlikely that the merger would have such an effect.[29]

3. HHIs in Petroleum Mergers the FTC Has Challenged

The agency regards market shares and concentration figures as useful initial indicators of the likelihood of potential competitive effects of mergers, but the FTC does not base its decisions to challenge mergers simply on market shares and HHIs. Further factual investigations and analyses of competitive effects, entry conditions, and efficiencies may reveal that anticompetitive effects are unlikely despite the initial indications of market shares and concentration.

Nonetheless, a review of the FTC's merger enforcement in oil markets from FY 1996 to FY 2003 reveals correlations between the HHI presumptions in the Merger Guidelines and the FTC's enforcement actions in particular oil markets. Table 2-6 shows that the FTC took enforcement action in 55 out of 75 oil markets in which the post-merger HHI would have been between 1,400 and 1,799. That table also shows that the FTC took enforcement action in 78 out of 110 oil markets in which the post-merger HHI would have been 1,800 to 2,399. For oil markets in which post-merger HHIs would have been 2,400 or above, the FTC took enforcement action in 75 out of 81 such markets. A comparison of Table 2-6 with the information that the FTC has published about its merger enforcement in other industries shows that, in mergers involving petroleum markets, the Commission has obtained relief at lower levels of concentration.[30]

The Commission has been especially concerned about potential non-competitive behavior in the petroleum industry. In addition, a particular oil merger may involve a large number of relevant markets, and thus may require an extraordinary amount of time to ascertain whether anticompetitive effects are likely. Merging parties sometimes desire to settle competitive concerns quickly and avoid a lengthy investigation of a large number of relevant markets. In such instances, the FTC staff may adopt screens using HHI thresholds at levels low enough to assure that any plausible competitive concerns are remedied.[31] In

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29 Merger Guidelines, § 1.51.

30 Federal Trade Commission, *Horizontal Merger Investigation Data, Fiscal Years 1996-2003* (Feb. 2, 2004). *See* FTC Energy and Commerce Committee Statement, at 4-5.

31 *But see* Statement of Commissioner Mozelle W. Thompson Concerning the FTC's Merger Enforcement Actions in the Oil Industry (June 2, 2004) (suggesting that time and cost are practical considerations for every merging party, and arise regardless of the industry involved; in addition, these considerations are weighed by the parties in accord with particular facts presented by the proposed transaction, and the parties' calculation as to whether they are likely to satisfy the Commission's merger review standard without having to defend against a Commission lawsuit, or enter into a settlement). Commissioner Thompson also argued that "various market conditions in the oil industry increase the likelihood" of anticompetitive effects in this industry arising from coordinated interaction among firms; these conditions include product homogeneity, existing business practices, the characteristics of buyers and typical transactions, and the availability of key information regarding market conditions, transactions, and individual competitors. *See* Statement of Chairman Timothy J. Muris Concerning FTC Merger Enforcement in the Oil Industry (June 2, 2004), noting that these factors (incorporated into the Horizontal Merger Guidelines framework for review of conditions conducive to coordinated interaction)

order to protect the public interest in competitive markets while accommodating those who desire to close quickly, the Commission has consistently required merger parties to bear the risk that relief might be over-inclusive, rather than imposing on the public the risk that relief might be under-inclusive.

Thus, in BP/Amoco and subsequent cases, the FTC staff employed HHI thresholds of a 100-point change in the HHI to a post-merger level of 1,500 for terminaling and a 100-point change to a post-merger level of 1,400 for gasoline marketing as screens for potential anticompetitive effects.[32] (As more in-depth fact gathering and analyses of competitive effects, entry, and efficiencies of individual relevant markets take place, offsetting factors may be uncovered that indicate that no relief is necessary even though HHI levels exceeded these thresholds.[33]) These post-merger HHI levels equate to approximately 7 equal-sized firms remaining in a market. Generally, the relief required in such situations is for the combined firm to divest all of the assets of one of the firms (in that relevant market) to a new competitor (for whom the acquired business represents a product or geographic extension) or an existing small competitor. In this way, the pre-merger competitive dynamics are, at a minimum, likely to be maintained, and may be enhanced by the actions of the new owners of the divested assets.

Whatever threshold of concentration the Commission uses as a screen, remedies requiring the divestiture of retail assets (*e.g.*, gasoline stations) may be over-inclusive (that is, include assets in markets where anticompetitive effects are not likely) because of concerns about the viability of a more limited package of assets. For example, a potential buyer may be able to capture economies of scale only if it operates or supplies a large number of gasoline stations. Thus, putting together a viable package of assets necessary to maintain or restore competition may require divesting a broader range of assets than those limited to the markets alleged in the complaint.[34]

Table 2-1 lists the 15 petroleum mergers in which the FTC has taken enforcement action since 1981. Table 2-5 provides all of the publicly available information on what would have been post-merger HHI levels, and what would have been the change in the HHI, for markets of concern in petroleum mergers

exist in many other industries, in none of which the Commission challenges mergers at such low levels of concentration.

[32] In the early 1980s, the Commission presumptively sought wholesale divestitures in oil mergers when the HHIs exceeded 1,000, and the change in the HHI exceeded 100. *See* Timothy J. Muris, Chairman, Federal Trade Commission, *How History Informs Practice, supra* note 23.

[33] In those few oil mergers that the Commission investigated that were of smaller size, the Commission did not seek enforcement at the low levels of concentration challenged in the larger mergers. In numerous markets in smaller transactions, the Commission did not seek relief when the post-merger HHI was in excess of 1,400 and below 2,000 (and the delta was 100 or more). *See* Statement of Chairman Timothy J. Muris Concerning FTC Merger Enforcement in the Oil Industry, supra note 31.

[34] *See* Staff of the Federal Trade Commission, *Frequently Asked Questions on Merger Consent Order Provisions* (Assets to be Divested). *See also* Statement of Chairman Timothy J. Muris Concerning FTC Merger Enforcement in the Oil Industry, *supra* note 31 (suggesting that, because of the concern about viability of the divestiture package, the use of the particular HHI screens discussed may not have as significant a practical impact as might otherwise be imagined).

challenged by the FTC since 1981.[35] The post-merger HHIs and HHI changes reported in Table 2-5 and Table 2-6 are those that would have resulted from the merger if there had been no divestitures.[36]

The FTC's enforcement approach in relevant markets for the bulk supply of refined products provides examples of the range of market concentration levels in which the FTC has taken action. Between 1981 and 2002 the FTC alleged reductions in competition in 9 mergers involving the bulk supply of refined products by refineries or pipelines. In Shell/Texaco, the FTC required relief when a merger would have increased the HHI for bulk supply of CARB gasoline in California by as little as 154 to a post-merger level as low as 1,635.[37] In Conoco/Phillips (northern Utah), the FTC required relief when a merger would have increased the HHI in a bulk supply market by 300 to a post-merger level of 2,100. The highest post-merger HHI (absent relief) among the six non-CARB gasoline cases where relief was obtained would have been 5,000, with a delta of 1,600 (RFG II in St. Louis, in Chevron/Texaco).

While they may establish certain presumptions, market shares and concentration do not communicate the mechanisms by which companies might raise price, reduce output, or achieve other anticompetitive effects post-merger. The Merger Guidelines' analytical framework (as well as the case law[38]) requires additional evidence to evaluate likely competitive effects.

D. Competitive Effects

To analyze a merger's likely competitive effects, the antitrust agencies develop and test potential theories of how a merger may result in increased prices, reduced output or quality, or other anticompetitive effects in a relevant market.[39] The Merger Guidelines describe factors that the agencies consider in evaluating theories of anticompetitive conduct by a single firm (that is, unilateral behavior[40]) or of conduct among two or more firms that is profitable to each only because of the accommodating reactions of the others

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35 These HHIs were calculated using the FTC's best assessment of the relevant antitrust market. Unlike the regional concentration data presented in other chapters, these data provide an accurate image of concentration in the relevant markets at issue. Public sources include FTC Complaints and Analyses to Aid Public Comment; however, not all Complaints and Analyses include concentration data.

36 Under these estimates, the merged firm's market share is simply the sum of the shares of the previously separate firms, while the post-merger market shares of non-merging firms equal their pre-merger shares. Competition in the post-merger environment may differ from that before the merger, however, so that actual post-merger market shares may not be equivalent to the simple summation of the pre-merger shares.

37 The highest post-merger HHI (absent relief) among the six CARB gasoline cases where relief was obtained would have been 3,050, with a delta of 1,050, in Valero/UDS (CARB 3 gasoline in northern California). In the other five markets, the post-merger HHIs were 1,699 in Exxon/Mobil (CARB gasoline in California); 1,750 in Valero/UDS (CARB 2 gasoline in California); 1,850 in Valero/UDS (CARB 3 gasoline in California); 2,000 in Chevron/Texaco (CARB gasoline in California); and 2,700 in Valero/UDS (CARB 2 gasoline in northern California), with changes in HHIs ranging from 171 to 750 (*see* Table 2-5).

38 *U.S. v. General Dynamics, supra* note 23; *U.S. v. Baker Hughes, Inc.*, 908 F.2d 981 (D.C. Cir. 1990); *U.S. v. Syufy Enter.*, 903 F.2d 659 (9th Cir. 1990).

39 In the case of monopsony or buyer market power, the effect would be reduced prices paid for inputs and a corresponding reduction in the supply or quantity of those inputs.

40 Merger Guidelines, § 2.2.

(that is, coordinated interaction[41]). Unilateral and coordinated theories of anticompetitive harm rely on different assumptions about how firms in a market likely will respond to each other's price and output changes.

1. *Single-Firm Conduct: Theories of Unilateral Anticompetitive Effects*

Under unilateral anticompetitive theories, the question is whether the merged firm can unilaterally reduce output and raise prices, given rivals' and consumers' likely responses to the higher prices. A critical question is whether a reduction in output by the merged seller would be profitable, taking into consideration the size of lost margins on sales that are forgone and the magnitude of supply responses by other sellers both in and out of the relevant market. For example, the size of the margins that are lost when a refinery reduces sales in a market often depends on the refinery's opportunities to sell that output in other markets. In assessing likely supply responses by other sellers in markets for bulk supply of refined products, the FTC considers capacity constraints at refineries and pipelines as well as the incentives of refineries to shift output among markets.[42] In addition, the FTC takes into account that suppliers with substantial existing shares may have somewhat limited incentives to increase sales to offset the output reduction from the merged firm because, as market participants, they benefit from a price increase on their existing sales.

When the shares of the merging firms in a properly delineated antitrust market are high and other market participants' supply responses to an anticompetitive price increase are likely to be weak, a merger may increase the likelihood of a unilateral exercise of market power by the merged firm. For example, in Chevron/Texaco, the FTC alleged that the merger was likely to have unilateral anticompetitive effects in the market for transportation of crude oil from certain offshore areas in the Gulf of Mexico. Only two pipelines could transport crude oil in that market, and Chevron owned 50% of one while Texaco participated in a joint venture that owned 100% of the other.[43]

Since 1981, there have been seven other petroleum merger cases where the FTC alleged that anticompetitive effects in relevant markets would arise solely from unilateral market power.[44] Although the concern in most of these matters was with a price increase from a reduction in output by the merged firm, some cases raised different concerns. For example, in Shell/Texaco, the FTC alleged that the joint venture would enable Shell to raise costs to a rival asphalt refinery.[45] In

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41 Merger Guidelines, § 2.1. Coordinated interaction "includes tacit or express collusion, and may or may not be lawful in and of itself." *Id.*

42 As noted earlier, in some cases alternative suppliers may have limited ability to increase their sales substantially in response to a price increase, because their refineries or pipelines may be operating at capacity, at least during significant time periods. *See* discussion of Conoco/Phillips, Ch. 2, Section II. B.3., *supra*.

43 Chevron/Texaco, Complaint ¶ 51 and Analysis to Aid Public Comment.

44 *See* Table 2-5, and note 46, *infra*.

45 The FTC's competitive concern in that market is discussed in Section II.D.3.c., *infra*. Commissioner Azcuenaga, who dissented from this part of the order (as well as other parts dealing with marketing and pipeline overlaps), did not find reason to believe that the joint venture would adversely affect competition in refining of asphalt in Northern California. *See*

BP/ARCO, the FTC alleged unilateral anticompetitive effects in bidding for ANS crude oil exploration rights in Alaska; BP and ARCO were the two most significant competitors for exploration leases for oil on the ANS.[46]

2. Coordinated Interaction Theories

A merger that significantly increases concentration in a properly delineated antitrust market may increase the likelihood and success of coordinated interaction among sellers to restrict market output and raise price. A coordinated interaction theory requires at least one or more of the merged firm's rivals to cooperate (tacitly or explicitly) with the merged firm in order to make profitable any anticompetitive price increases from output reductions. Under a coordinated interaction theory, such rivals must either reduce output themselves or react less than fully competitively to a price increase to accommodate the output reductions of the merged firm. More generally, "coordinated interaction" refers to those actions by a group of firms that are profitable for each of them only as a result of the accommodating reactions of the others. To evaluate these theories, the FTC assesses which suppliers would have to be part of the coordinating group for prices to increase, whether their incentives would be sufficiently aligned with those of the merged firm that consensus would be feasible, how easy it would be to reach consensus, and whether firms could detect and punish deviations from the coordinated outcome. Part of this analysis involves assessing whether there is evidence of current coordination among market participants.

The FTC frequently has concluded that, given sufficient concentration, conditions in relevant markets in the petroleum industry would permit coordinated interaction by sellers. The relevant product markets in which the FTC has alleged coordinated effects generally have involved the refining and bulk supply, pipeline transportation, terminaling, or marketing of light petroleum products.[47] The transportation of crude oil is another area where the agency has alleged a likelihood of coordinated effects.[48]

For example, in Shell/Texaco, the FTC alleged that the joint venture would facilitate coordinated interaction among refiners of conventional gasoline and kerosene jet fuel in the Pacific Northwest, among refiners of CARB gasoline in California, and among wholesalers of gasoline.[49] In

Commissioner Azcuenaga's Statement Concurring in Part and Dissenting in Part.

46 BP/ARCO, Complaint ¶¶ 46, 48, and Analysis to Aid Public Comment. Other relevant markets where the FTC alleged only unilateral effects are: Gulf/Cities Service, Complaint ¶19 (relating to pipeline transportation of refined products); Texaco/Getty, Complaint ¶¶ 59 (a), (f) (relating to refining of light petroleum products and crude oil transportation); Conoco/Asamera, Complaint ¶ 14 (relating to purchase of crude oil); Exxon/Mobil, Complaint ¶ 54 (relating to refining and marketing of jet turbine oil); BP/ARCO, Complaint ¶¶ 42, 66 (relating to production and sale of ANS crude, and manipulation of crude oil futures markets as a result of control over crude oil transportation and storage services); Conoco/Phillips, Complaint ¶ 129 (relating to natural gas gathering).

47 *E.g.*, Gulf/Cities Service, Complaint ¶¶ 20, 22; Texaco/Getty, Complaint ¶¶ 59(b), (c), (d); Chevron/Gulf, Complaint ¶ 41; Sun/Atlantic, Complaint ¶ 11; Shell/Texaco, Complaint ¶¶ 33, 35, 37; BP/Amoco, Complaint ¶¶ 23, 25; Exxon/Mobil, Complaint ¶¶ 36, 46; Chevron/Texaco, Complaint ¶¶ 37, 43, 45; Conoco/Phillips, Complaint ¶¶ 18, 37, 87, 93.

48 Exxon/Mobil, Complaint ¶ 48; Chevron/Texaco, Complaint ¶ 49.

49 Shell/Texaco, Analysis to Aid Public Comment.

BP/Amoco, the FTC alleged that the merger would facilitate coordinated interaction on wholesale gasoline prices in 30 cities or metropolitan areas.[50] In Exxon/Mobil, the FTC asserted that the merger would facilitate coordinated interaction in the refining, terminaling, and marketing of refined products in geographic markets including California and numerous metropolitan areas in the Northeast, Mid-Atlantic, and Texas.[51] The FTC made similar allegations regarding coordinated interaction in Chevron/Texaco and Conoco/Phillips.[52]

3. *Other Competitive Effects Alleged by the FTC*

a. Monopsony

Buyer market power, as well as seller market power, can be of competitive concern.[53] The FTC opposed the 1986 Conoco/Asamera merger in part because the merger would have combined the only two effective refinery purchasers of crude oil in a certain part of Colorado and would have given the merged firm increased market power in purchasing crude oil from that area. The Commission concluded that the merged company was likely to reduce its purchases of crude oil in that market in order to reduce the price paid to local crude oil producers below pre-merger levels.[54]

b. Potential Competition

The FTC alleged a loss of "potential competition"[55] in 1987 in Pacific Resources/Shell (terminaling and marketing of light petroleum products on three Hawaiian islands) and in 1999 in Exxon/Mobil (marketing of gasoline in Arizona).[56] In each case, one of the merging parties was a potential competitor that provided an important constraint on prices in a relevant market in which the other merging party already competed. In 2000, in BP/ARCO, the FTC alleged a loss of potential competition from ARCO in the future commercialization of ANS natural gas, because ExxonMobil, BP Amoco, and ARCO were the only three companies with sufficient gas reserves to compete in that market.[57]

c. Raising Rivals' Costs

The FTC's 1997 complaint against Shell and Texaco's joint venture (Equilon) alleged harm to consumers arising from concerns that the merged firm could "raise rivals' costs."[58] Texaco owned the only pipeline that supplied undiluted heavy crude oil to Shell's largest competitor in the refining

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50 BP/Amoco, Analysis to Aid Public Comment.

51 Exxon/Mobil, Analysis to Aid Public Comment.

52 Chevron/Texaco, Analysis to Aid Public Comment; Conoco/Phillips, Analysis to Aid Public Comment.

53 *See* Merger Guidelines, § 0.1.

54 Federal Trade Commission, *FTC Seeks Injunction to Block Conoco's Acquisition of Asamera* (Dec. 30, 1986) (press release).

55 *See generally* the 1984 Merger Guidelines at § 4.1. U.S. DEP'T. OF JUSTICE MERGER GUIDELINES, *reprinted in* 4 Trade Reg. Rep. (CCH) ¶13,103.

56 PRI/Shell, Complaint ¶ 12; Exxon/Mobil, Analysis to Aid Public Comment.

57 BP/ARCO, Analysis to Aid Public Comment.

58 The 1984 Merger Guidelines, § 4.21, recognized foreclosure as a potential competitive harm. U.S. DEP'T OF JUSTICE MERGER GUIDELINES, *reprinted in* 4 Trade Reg. Rep. (CCH) ¶13,103. For a discussion of theories and application of "raising rivals' costs," *see* David Scheffman & Richard Higgins, *20 Years of Raising Rivals' Costs: History, Assessment and Future, available at* http://www.ftc.gov/be/RRCGMU.pdf (forthcoming in the GEO. MASON L. REV.), and the literature cited therein.

of asphalt in northern California. The FTC concluded that the joint venture would have lessened competition by "providing the combination of Shell and Texaco with the incentive and ability to raise the cost of undiluted heavy crude oil by pipeline to the competing refiner of asphalt in the San Francisco Bay area."[59] The Shell/Texaco joint venture allegedly would have done this by raising the Texaco pipeline's tariffs or otherwise reducing the rival asphalt refinery's access to the pipeline's crude. This strategy would have been profitable if the joint venture could have raised its rival's costs sufficiently, because losses in crude transportation profits (due to an increase in Texaco's pipeline tariff above pre-merger profit-maximizing levels) would have been exceeded by additional profits for Shell's refinery because of lessened competition in asphalt.

In Exxon/Mobil, the FTC alleged that a competing terminal in the Norfolk, Virginia area could have been put at a competitive disadvantage as a result of Exxon's acquisition of a wharf owned by Mobil. Although Exxon operated a terminal in the area and Mobil did not, Mobil owned a wharf that another terminal firm sometimes used to receive gasoline shipments. Because that firm was in competition with Exxon's terminal, the FTC concluded that Exxon might have denied (or increased the price of) access to the wharf so as to limit the other firm's ability to compete against Exxon in terminaling of gasoline.[60]

E. Entry

The FTC will not allege likely anticompetitive effects from a merger without considering whether entry by new competitors would be "timely, likely, and sufficient" in its magnitude, character, and scope to deter or counteract the competitive effects of concern.[61] Entry is "timely" if it would achieve "significant market impact" within a relatively short period, usually two years. In general, the FTC has not found entry to be likely in petroleum refining; the sheer complexity of entry (both inherent and due to environmental restrictions) is a significant barrier to timely entry. In numerous petroleum transactions, including Shell/Texaco, BP/Amoco, Exxon/Mobil, BP/ARCO, Chevron/Texaco, Valero/UDS, and Conoco/Phillips, the FTC has alleged that entry into refining, bulk transport, and terminaling would not be timely.[62]

Whether entry is "likely" depends on how profitable it would be at pre-merger prices in light of the entrant's variable, fixed, and sunk costs, as well as the entrant's presumptions about sales opportunities available upon entry. Consistent with this entry test, for example, in Exxon/Mobil the FTC

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59 Shell/Texaco, Complaint ¶ 31. Even though refineries often have choices among types of crude oil to run, Shell's asphalt competitor had a specialized asphalt refinery for which undiluted heavy crude was the only low-cost type of crude oil.

60 Exxon/Mobil, Analysis to Aid Public Comment.

61 Merger Guidelines, § 3.0. Entry analysis in this section involves "committed entrants" – that is, new entrants that would have to incur significant sunk costs (*i.e.*, costs which could not be recouped within one year) of entry and exit. As noted earlier, "uncommitted entrants" are treated as market participants.

62 *See* Analyses to Aid Public Comment in Shell/Texaco, BP/Amoco, Exxon/Mobil, BP/ARCO, Chevron/Texaco, Valero/UDS, and Conoco/Phillips.

alleged that a wholesale entrant on Guam would need access to sufficient terminal capacity and retail outlets to permit it to purchase full tanker-loads of gasoline; entry at a smaller scale would not be profitable because of the high fixed cost of importing product by tanker. Wholesale entry was not likely to occur on Guam due to a scarcity of terminal capacity and available retail outlets.

Finally, the FTC assesses whether entry would be "sufficient" to return market prices to pre-merger levels. The sufficiency requirement recognizes that fringe entry may be timely and likely but may not be of sufficient scale to defeat the anticompetitive effects of a merger. For example, in Shell/Texaco, the FTC alleged that, because of extensive vertical integration in marketing in San Diego, entry solely at the wholesale level would not be sufficient; a wholesaler would need a "critical mass" of retail stations to provide "sufficient" competition to return market prices to pre-merger levels.[63]

F. Efficiencies

The Merger Guidelines recognize that mergers have the potential to generate significant efficiencies. "Efficiencies generated through merger can enhance the merged firm's ability and incentive to compete, which may result in lower prices, improved quality, enhanced service, or new products."[64] Thus, the FTC will not challenge a merger "if cognizable efficiencies are of a character and magnitude such that the merger is not likely to be anticompetitive in any relevant market."[65] The efficiencies must be "cognizable," however; *i.e.*, they must be "merger-specific;"[66] must be verifiable; and must not arise from anticompetitive reductions in output or service.[67]

The merging parties often claim that efficiencies are likely to result from the proposed transaction. Chapter 4 reviews the publicly available record on claimed efficiencies and business rationales for certain petroleum mergers, including some transactions that were not challenged by the FTC. The most commonly cited source of efficiencies was "operating synergies" or "organizational efficiencies." These savings appear related to administrative and corporate overhead functions, as well as reductions in staff. Another common source of claimed efficiencies was the integration of refinery, pipeline, or other distribution systems. For upstream transactions, the most common efficiency claim was increased economies of scale.

Cognizable efficiencies have sometimes played a role in an FTC decision not to challenge a petroleum merger. For example, the decision not to challenge the Tosco/Unocal merger, which involved a combination of California refineries, was influenced by a conclusion that the transaction offered

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63 Shell/Texaco, Analysis to Aid Public Comment.

64 Merger Guidelines § 4.

65 *Id.* (footnote omitted).

66 Merger-specific efficiencies are those that are "likely to be accomplished with the proposed merger and unlikely to be accomplished in the absence of either the proposed merger or another means having comparable anticompetitive effects." *Id.*

67 *Id.*

real synergies.[68] The FTC also saw potential efficiencies arising out of Sunoco's acquisition of the Coastal Eagle Point refinery, located in Westville, New Jersey. After first discussing the reasons why the transaction was unlikely to have anticompetitive effects, the FTC further noted that Sunoco had presented credible evidence that the acquisition was likely to produce substantial merger-specific efficiencies relating to refinery synergies and optimization. The FTC concluded that these efficiencies were likely to contribute significantly to the continued viability of the acquired refinery in light of the upcoming investments needed to satisfy regulatory requirements for cleaner-burning fuels.[69]

III. Remedies in Petroleum Merger Enforcement Actions

Since 1981, the FTC has alleged that 15 announced large petroleum mergers would have resulted in significant reductions in competition and harmed consumers in one or more relevant markets, if consummated. Most of these mergers would have reduced competition in a number of different markets. For all 15, the FTC obtained structural relief that prevented reductions in competition. For 11, the FTC obtained divestitures, including refineries and substantial interests in numerous pipelines, terminals, and wholesale and retail marketing assets. One of the 11 was BP/ARCO, where the Commission authorized staff to seek a preliminary injunction but obtained a consent agreement with the parties before the district court heard the matter. The remaining four mergers were not consummated. Two were abandoned (Gulf/Cities Service and Conoco/Asamera), and another was enjoined by the court (PRI/Shell), after the FTC took action to obtain preliminary injunctions. In the fourth case, the FTC sought a preliminary injunction, but the transaction was abandoned following the result of private antitrust litigation (Mobil/Marathon).

The last column of Table 2-5 lists the actions the FTC required merging parties to take to resolve competitive risks. The remedies involved primarily asset divestitures, but some orders included conduct requirements. The FTC seeks remedies that maintain the pre-merger level of competition. A straightforward way to accomplish this outcome is to sell the assets of one of the merging parties operating in the relevant market.[70] However, at times, the Commission has required a divestiture to include assets outside of the market of competitive concern, if such assets were necessary to ensure the viability of the divested business.[71] Generally, the

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68 Robert Pitofsky, *Efficiencies in Defense of Mergers: Two Years After*, 7 GEO. MASON L. REV. 485, 487 (1999).

69 Sunoco/Coastal Eagle Point, Statement of the Commission.

70 In some instances, the FTC has permitted merging firms to resolve competitive concerns in a relevant market with divestiture of assets from both firms. For example, in Conoco/Phillips, the remedy regarding the bulk supply of light petroleum products in Eastern Colorado required divestiture of Conoco's refinery and of Phillips's marketing assets in the area. Conoco/Phillips, Analysis to Aid Public Comment.

71 "In most situations, the staff is most likely to support the parties' offer to divest an autonomous, on-going business unit that comprises at least the entire business of one of the merging parties in the relevant market, attempting to recreate the premerger competitive environment. . . . In fact, this may include business components relating to markets outside the relevant geographic or product market, if such

assets were divested to an entity that did not, at the time, compete in the market of competitive concern, leaving the current market structure unchanged.[72] At times, however, remedies have involved sales to companies that had small shares in the relevant markets.[73] Most of the remedies left market concentration unchanged from the pre-merger level; the few exceptions involved very small increases.[74]

A. Crude Oil Exploration, Production, and Transportation

Concentration is relatively low in most relevant markets for crude oil exploration and production.[75] Thus, the FTC has not frequently sought relief in mergers affecting these areas. Only in BP/ARCO did the FTC seek relief to prevent seller market power in crude oil exploration or production.[76] To remedy competitive harm in this and other crude-related markets, the FTC required divestiture of ARCO's Alaska assets (that is, its crude oil exploration and production assets), ARCO's 22% interest in the Trans-Alaska Pipeline System ("TAPS"), and ARCO's specialized tanker ships.

Most of the other crude-related competitive problems from mergers have stemmed from the merging parties' both providing crude oil pipeline transportation from production fields. Table 2-2 summarizes merger remedies relating to crude oil that have been obtained by the FTC since 1981. In Chevron/Gulf, the FTC required divestiture of Gulf's interests in various crude pipelines in West Texas and New Mexico. The remedy in Exxon/Mobil was divestiture of Mobil's 3% interest in TAPS. In Texaco/Getty, the FTC required Texaco to sell heavy California crude oil and crude pipeline access to former Getty customers under specified terms. In Shell/Texaco, the competitive concern related to the transportation of undiluted heavy crude oil on Texaco's pipeline to an asphalt refinery in the San Francisco Bay area that competed with a Shell refinery. The remedy was a 10-year extension of Texaco's agreement to supply crude oil to the refinery. Although divestiture is the standard remedy for competitive problems created by mergers, non-structural remedies may sometimes be appropriate, as in this case. In effect, the supply arrangement preserved the pre-existing business relationship between the pipeline and the

components are necessary to assure that the buyer will maintain or restore competition." *Statement of the Federal Trade Commission's Bureau of Competition on Negotiating Merger Remedies.*

72 However, the Commission does not have a "zero delta" policy. *See* Staff of the Federal Trade Commission, *Frequently Asked Questions About Merger Consent Order Provisions* (The Assets to Be Divested).

73 Smaller firms already operating in a market may be more viable competitors than firms not currently operating in a market. *See* Staff of the Federal Trade Commission, *Frequently Asked Questions About Merger Consent Order Provisions* (Buyers).

74 For example, in addressing competitive concerns in CARB gasoline in the Valero/UDS merger, the FTC approved divestiture of UDS's Avon, California refinery to Tesoro, even though this sale resulted in a small increase in concentration because of Tesoro's limited shipments of gasoline into California. Valero/UDS, Concurring Statement of Commissioner Mozelle W. Thompson.

75 Moreover, concentration has remained low in crude production and reserves as measured at both the world and domestic levels.

76 BP/ARCO, Analysis to Aid Public Comment. In a statement dissenting in part, Chairman Pitofsky and Commissioner Thompson concluded that additional relief was warranted in this matter. Specifically, they believed that the FTC also should have prohibited BP and Phillips (the acquirer of the divested ANS assets) from exporting ANS crude oil at a loss for the purpose of increasing ANS spot prices in PADD V.

affected refinery, thereby preserving the pre-merger market conditions.[77] This preserved efficiencies likely to stem from the merged firm's control of a pipeline serving its refinery (the Texaco pipeline served the Shell refinery as well as the competing third-party asphalt refinery). In addition, the long-term supply remedy in Shell/Texaco could be monitored and enforced relatively easily, and it fully addressed the concerns in the downstream (asphalt) market.

B. Bulk Supply of Refined Products

Since 1981, the FTC has alleged that nine mergers would significantly reduce competition in the bulk supply of light petroleum products because of competitive overlaps between the refineries and/or pipelines of the merging parties. Table 2-3 summarizes the FTC enforcement actions in bulk supply of refined light petroleum products.[78] Two of these mergers were abandoned after FTC enforcement action. The other competitive concerns were resolved by divestitures of eleven refineries (plus divestiture of four other refineries in geographic areas not of competitive concern)[79] and interests in four refined product pipelines.[80] In some bulk supply cases involving refinery divestitures, associated assets such as crude or product pipelines and downstream marketing assets were also required to be divested to assure the continued viability of the refinery.[81]

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77 Remarks of Richard G. Parker, Senior Deputy Director, Bureau of Competition, Federal Trade Commission, *Trends in Merger Enforcement and Litigation* (Sept. 16, 1998).

78 In addition to these cases involving refined light petroleum products, the FTC in Conoco/Phillips required divestiture of assets to resolve competitive problems in bulk supply of propane in three geographic areas. The parties agreed to divest Phillips's propane business at Jefferson City and East St. Louis. Moreover, since ConocoPhillips would control the Blue and Shocker pipelines connecting the divested assets with the propane market hub in Conway, Kansas, ConocoPhillips was required to grant the asset buyer non-discriminatory access to transport propane on those pipelines.

79 Refinery divestitures made to resolve FTC competitive concerns were Texaco's refinery at Eagle Point (Westville), New Jersey (Texaco/Getty); Gulf's refinery at Alliance, Louisiana (Chevron/Gulf); Shell's refinery at Anacortes, Washington (Shell/Texaco); Exxon's refinery at Benicia, California (Exxon/Mobil); UDS's refinery at Avon, California (Valero/UDS); Texaco's joint venture interest in the Equilon refineries at Martinez, Wilmington, and Bakersfield, California and Anacortes, Washington (Chevron/Texaco); Conoco's refinery at Denver, Colorado (Conoco/Phillips); and Phillips's refinery in Salt Lake City, Utah (Conoco/Phillips).

Although not involving refinery overlaps related to relevant markets where competitive concerns were raised, the FTC consent in Chevron/Texaco also resulted in divestiture of Texaco's joint venture interest in the Motiva refineries at Port Arthur, Texas, Norco and Convent, Louisiana, and Delaware City, Delaware.

80 The divested pipeline interests were Gulf's 17% interest in the Colonial Pipeline (Chevron/Gulf); either Shell's 24% interest in the Plantation Pipeline or Texaco's 14% interest in the Colonial Pipeline (Shell/Texaco); either Exxon's 49% interest in the Plantation Pipeline or Mobil's 11% interest in the Colonial Pipeline (Exxon/Mobil); and Texaco's interests in Equilon, including Equilon's interests in the Explorer and Delta Pipelines (Chevron/Texaco).

81 For example, in Exxon/Mobil the FTC required, as part of the relief involving divestiture of Exxon's Benicia, California refinery, that Exxon also divest its gas stations in California and assign its lessee contracts and jobber supply contracts in California to the buyer of the refinery. The FTC also required that Exxon provide the refinery buyer an option to enter into a supply contract for a ratable quantity of ANS crude oil, up to 100 MBD or the Benicia refinery's historic usage. (Exxon is one of the three major producers of ANS crude oil, and Benicia had relied heavily on ANS supply.) Exxon/Mobil, Analysis to Aid Public Comment.

Similarly, in relief accompanying divestitures of two refineries in Utah and Colorado in Conoco/Phillips, the FTC required divestiture of crude oil supply pipelines, truck loading racks, light petroleum product pipelines and storage terminals

There have been significant changes in bulk supply conditions since the 1980s, some of which may have important implications for the competitive effects of specific mergers. Refinery and pipeline capacity bottlenecks appear to have become more frequent in some areas during the 1990s. Other things equal, such bottlenecks may increase competitive concerns with mergers in these areas. Yet new pipelines and pipeline expansions have made it less likely that mergers would cause competitive problems in other areas. The proliferation of mandated gasoline grades in some areas of the country has affected product market definition and entry conditions. New regulations to meet tighter environmental standards in some instances have increased the time needed for entry and the cost of entry.

C. Terminaling

Enforcement to prevent competitively problematic combinations of refined product terminals has been important throughout the period since 1981. The FTC has alleged that seven mergers would reduce competition in terminaling.[82] One of those mergers was not consummated. In the remaining six cases, competitive concerns relating to terminaling were resolved by divestitures.

In two of those six cases, resolving concerns relating to terminaling in one geographic market required measures in addition to divestitures. In Exxon/Mobil, the remedy for one terminaling problem was the continuation of competitor access to a wharf owned by Mobil. A competitor occasionally used Mobil's wharf to receive gasoline shipments for its terminals, which competed with Exxon's. The order required ExxonMobil to continue to offer access to the Mobil wharf on the same terms as it had been offered historically, for as long as ExxonMobil owned the wharf.[83] In Conoco/Phillips, to resolve a problem in one geographic market, the FTC required a 10-year terminal throughput agreement with an option to buy a 50% undivided interest in the Phillips terminal. The throughput agreement, which could not specify any minimum volume and specified a maximum volume of 8,500 barrels per day at the Phillips terminal, in effect established the throughput customer as an independent competitor in the local terminal market, even if the option to buy one-half of the Phillips terminal was not exercised. The throughput agreement also provided for the supply of additive and information technology services.[84]

D. Marketing

For light petroleum products, "marketing" refers to activities downstream from terminals – that is, wholesale and retail distribution. The FTC's analysis of the likely effects of petroleum mergers on marketing in recent years has focused on the consolidation of brand-related assets, including brand-owner control of retail

used in the operation of the refineries and the gasoline stations served by the refineries. The consent package also included reassignment of contracts with distributors and, for a limited period, the licensing of brand rights. Conoco/Phillips, Analysis to Aid Public Comment.

82 *See* Tables 2-3, 2-5.

83 Exxon/Mobil, Analysis to Aid Public Comment.

84 Conoco/Phillips, Decision and Order, ¶ VI.

sites. To understand this approach to competitive issues in gasoline marketing, some structural features of the vertical relations between wholesalers and retailers and the role of independent distributors or jobbers should be highlighted.

1. Gasoline Distribution Channels

A brand owner in a given geographic market may distribute gasoline in several ways:

a. Brand deliveries to a brand owner's retail outlets

From a terminal, a brand owner may deliver branded gasoline to retail outlets that it owns and operates; in this case, the brand owner sets retail prices directly, and there is no wholesale market price to be observed.

b. Brand deliveries to lessee dealers

Alternatively, the brand owner may deliver gasoline to retail outlets that are operated by independent retail dealers under lease agreements; in this case, the brand owner sets a dealer tankwagon ("DTW") price at which sales are made to lessee dealers.[85]

c. Brand sales to jobbers at the terminal rack

In still other cases, the brand owner sells branded gasoline at the terminal rack to jobbers, who deliver gasoline to retail stations, which in many instances are owned by the jobber. In this case, the brand owner sets a rack price at which sales are made to jobbers and may also provide discounts, rebates, and allowances from rack prices under negotiated supply contracts. Brand owners may also make loans to jobbers to modernize or improve stations owned by jobbers. Typically, these loans are repaid through charges assessed against the purchase of gasoline from the brand owner. A brand owner may also sell unbranded gasoline to jobbers who deliver to stations flying the flag of some other brand, which in many cases is a minor or discount brand.[86]

Thus, depending on the situation, which tends to differ significantly across geographic markets, a brand owner may set branded retail prices, branded DTW prices, branded rack prices, or unbranded rack prices.

2. Competitive Effects of Concern and Recent Trends

The FTC has focused on how a merger might permit brand owners to exercise market power post-merger to the detriment of consumers, either unilaterally or through coordinated interaction. Important considerations in this analysis are the level of concentration at the brand level, the ease with which a sufficient number of jobbers could switch to other brands or unbranded products in response to an anticompetitive price increase, and entry conditions, including any impediments that new marketers might face in securing new retail locations or arranging for bulk supply or terminal services on competitive terms.

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[85] In addition, the lessee dealer makes rental payments for the retail site itself. Another class of retail dealers, so called "open dealers," own the retail locations themselves. They may also be supplied on a DTW basis by a brand owner or by a jobber. The number of open dealers in a market is typically small compared to brand-owner or jobber-owned stations, however.

[86] In some instances, other marketers with no branded presence may also sell unbranded gasoline from terminal racks. For example, independent refiners with no marketing assets or independent terminal operators may offer unbranded product at the terminal.

Recent trends could either decrease or increase concerns about anticompetitive effects, depending on particular circumstances. An important development in many areas of the country is the increasing role of non-refiner marketers that typically are not associated with major brands. A related development that has reduced the likelihood of concerns arising in some mergers is the increasing role of hypermarkets in gasoline retailing.[87] On the other hand, the duration of contracts involving loans from branded marketers to jobbers has increased. Increased contractual obligations in some instances have significantly reduced jobbers' abilities to switch brands should there be an anticompetitive increase in wholesale prices.

Shell/Texaco represented the first instance in which the FTC alleged that, independent of overlaps for refineries or terminals,[88] a petroleum industry transaction would reduce competition in the marketing of light petroleum products (specifically, gasoline sales).[89] The FTC's concerns about gasoline marketing focused on a competitive overlap that this joint venture would have created in San Diego, California. Six vertically integrated companies accounted for 90% of gasoline sales at both the wholesale and retail levels in San Diego. The transaction would have increased the HHI for marketing by 250 to a post-merger level of 1,815. The FTC observed that average wholesale prices in San Diego exceeded those in Los Angeles by more than the pipeline transportation cost from Los Angeles, from which San Diego receives its bulk supply. No pipeline bottleneck could explain the price difference; branded retailers were required by the oil companies to buy their gasoline at San Diego terminals. Given these facts, the Commission was concerned that the San Diego market was not fully competitive pre-merger, and that the merger would lessen competition further. Entry by new marketers was unlikely to preclude

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[87] Hypermarkets include grocery supermarkets, mass-merchandise retailers, and membership clubs.

[88] In various merger cases both before and after Shell/Texaco, the FTC concluded that the divestiture of a refinery was necessary to resolve a competitive problem in a market for bulk supply of refined products. In some of these cases, the FTC also concluded that it was necessary for marketing assets, including wholesale and retail distribution assets, to be divested together with the refinery. Divestiture of assets downstream from the refinery maintained important existing business relationships so as to preserve the competitive viability of the refinery and the new owner's investment incentives. For example, in connection with the divestiture of Exxon's Benicia, California, refinery in Exxon/Mobil, the FTC required the divestiture to the refinery buyer of approximately 85 owned or leased Exxon retail stores as well as supply agreements involving 275 additional stores in California. Exxon/Mobil, Analysis to Aid Public Comment. Similarly, in Valero/UDS, the FTC required that divestiture of UDS's San Francisco Bay Area refinery include divestiture of 70 UDS owned and operated retail stores to the same buyer. Valero/UDS, Analysis to Aid Public Comment.

In other cases, the FTC concluded that the divestiture of a light refined product terminal was necessary to resolve a competitive problem in a market for terminal services. In some of these cases, the FTC concluded that to preserve the competitive viability of the divested light refined product terminal, it was necessary for marketing assets to be divested along with the terminal. In PRI/Shell and Sun/Atlantic, for example, the FTC alleged competitive problems in markets that included both terminaling *and* marketing.

[89] Although Shell/Texaco was the first FTC merger enforcement action to allege competitive problems downstream and independent of terminal overlaps, the complaint in that matter characterized the concerns in terms of gasoline wholesaling and retailing markets. BP/Amoco expressed concerns downstream of terminals as occurring in wholesale markets. Beginning in Exxon/Mobil and continuing with subsequent cases, the FTC has consistently used the term "gasoline marketing" in reference to concerns downstream of terminals.

a lessening of competition. The FTC alleged that in San Diego, a marketer needed a critical mass of retail stations to be competitive, and barriers to entry existed at the retail level due to slow population growth, limited availability of retail sites, and permitting requirements. The FTC therefore required the joint venture partners to divest a package of retail gasoline outlets, with specified minimum individual and combined volume, to a single entity to create a viable new wholesale competitor.[90]

Several subsequent petroleum mergers have raised similar concerns in gasoline marketing, and the FTC has obtained extensive divestitures of owned and franchised retail outlets, as well as other remedies, in those matters. For example, the BP/Amoco consent agreement required divestiture of company-owned retail outlets in eight local markets in the southeastern and midwestern U.S., where the proposed merger would have resulted in post-merger marketing HHIs (based on reported flag shares) ranging from 1,400 to over 1,800. The merging firms were also required to release jobbers and open dealers from certain contractual restrictions in 30 areas. Amoco or BP jobbers and open dealers in these areas obtained an option to cancel their franchise and supply contracts, freeing them to switch to other wholesalers.[91] The Commission majority believed that jobbers and open dealers were unlikely to switch from major incumbent branded marketers to either fringe suppliers or new entrants.[92]

In Exxon/Mobil, the FTC concluded that the merger raised concerns in gasoline marketing due to overlaps in relevant markets located in the Northeast and Mid-Atlantic regions and in some metropolitan areas of Texas. At least in the Northeast and Mid-Atlantic regions, the Commission found it would not be sufficiently easy for smaller suppliers and new entrants to obtain additional retail sites and thereby prevent anticompetitive price increases by the incumbents. As in BP/Amoco, the FTC did not see substantial evidence in its Exxon/Mobil investigation that enough jobbers and open dealers were likely to switch away from their existing major brands in the event of an anticompetitive price increase. This was another reason why it appeared unlikely that entrants could obtain a sufficient number of existing retail outlets to make post-merger anticompetitive behavior unprofitable. To address the competitive concerns that the Exxon/Mobil transaction raised in gasoline marketing, the FTC required the divestiture of company-owned retail outlets and the reassignment of franchise and supply contracts in Texas and the Northeast and

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90 Shell/Texaco, Analysis to Aid Public Comment.

91 Certain types of debt could not be cancelled by the jobber, and contracts could not be cancelled to switch to another wholesale seller that already had 20% or more of that market. BP/Amoco, Analysis to Aid Public Comment.

92 BP/Amoco, Statement of Chairman Robert Pitofsky and Commissioners Sheila F. Anthony and Mozelle W. Thompson. Commissioner Swindle dissented in part, believing the merger was "unlikely to have anticompetitive effects in southeastern United States markets for the wholesale sale of gasoline" because "[a]ny effort by wholesalers to pass on a collusive price increase would be defeated" by branded retail gasoline stations switching wholesalers in response to entry by new wholesalers, or through cheating on a collusive agreement among existing wholesalers. BP/Amoco, Statement of Commissioner Orson Swindle, Concurring in Part and Dissenting in Part.

Mid-Atlantic regions.[93] The acquirer of the divested assets also obtained the right to continue to use the Exxon or Mobil brand name at the divested retail outlets for a limited period. Although the Exxon/Mobil merger may not have raised anticompetitive concerns in every relevant market within these geographic regions, effective relief required maintaining the business and organizational integrity of the divested brands across these broad geographic areas.

Concerns about potential anticompetitive effects in gasoline marketing also arose in Chevron/Texaco. Relief was most easily and effectively achieved by requiring a divestiture of Texaco's interest in the Equilon and Motiva joint ventures to the other partners in the joint ventures or to a buyer acceptable to the FTC. This action precluded any reduction in competition in gasoline marketing in numerous metropolitan areas (especially in the western and southern United States) that would have resulted from Chevron's acquiring Texaco's interests in the two joint ventures.[94]

Petroleum mergers do not always present competitive problems in relevant markets for gasoline marketing. For example, the FTC did not require marketing divestitures in Phillips/Tosco. Phillips's and Tosco's marketing operations were generally in different parts of the country, and in "those few metropolitan areas where their gasoline marketing businesses overlap[ped] significantly, they [had] a relatively low combined market share." The Commission went on to note that "[t]his area-by-area approach was mandated by sound antitrust policy, as reflected in the Horizontal Merger Guidelines."[95]

In the Conoco/Phillips merger, both Phillips and Conoco marketed gasoline in the Mid-continent, Southeast, and Southwest regions of the United States. Nonetheless, the FTC concluded that the merger was not likely to reduce competition in marketing.[96] There were several reasons for this conclusion. First, the two firms owned and/or operated few retail outlets, and, with the exception of a small number of cities, they relied primarily on jobbers for gasoline distribution. Second, unlike other brand-name marketers, the firms had not imposed significant costs of switching brands or debranding upon most of their jobbers.[97] Third, the FTC observed significant growth in low-price gasoline retailing by supermarkets, club stores, and mass merchandisers in the regions where Phillips and Conoco competed. Entry by these low-price

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93 Exxon/Mobil, Analysis to Aid Public Comment. Commissioner Swindle dissented in part and would not have required that ExxonMobil divest or assign its retail gasoline stations in wholesaling and retail markets that would have been only moderately concentrated after the merger. Writing in a separate statement, the Commission majority concluded there were sufficient precedential and evidentiary reasons to secure relief in these moderately concentrated markets. *See* Exxon/Mobil, Statement of Chairman Robert Pitofsky and Commissioners Sheila F. Anthony and Mozelle W. Thompson; Statement of Commissioner Swindle, Concurring in Part and Dissenting in Part.

94 Chevron/Texaco, Analysis to Aid Public Comment.

95 Phillips/Tosco, Statement of the Commission.

96 The FTC required the divestiture of certain marketing assets in Colorado and Utah that were supplied by two refineries, in order to remedy competitive problems at the bulk supply level. Conoco/Phillips, Analysis to Aid Public Comment.

97 As a general matter, outstanding loans by brand-name marketers to jobbers for retail station upgrades must be immediately repaid to a marketer if a jobber wishes to switch to another brand.

sellers had induced jobbers to switch brands or to de-brand.[98] The FTC believed that growth by these low-price formats was likely to continue, because supplies of gasoline were plentiful in light of common carrier pipelines and terminals offering both branded and unbranded product to jobbers in the overlap areas. In short, the existence of relatively little vertical control over retail operations by Phillips and Conoco, the potential for significant switching among brands by jobbers in the event of an anticompetitive price increase, and evidence of relatively easy entry into marketing in the overlap areas, among other factors, led the FTC to conclude that the Conoco/Phillips merger would not reduce competition in gasoline marketing.

The FTC also has examined whether mergers have had anticompetitive effects in the marketing of refined products other than gasoline. In Chevron/Texaco, the FTC alleged that the transaction was likely to reduce competition in marketing of aviation fuels to general aviation customers in the southeastern and western United States. Marketers of general aviation fuels sell to branded dealers known as "fixed base operators" ("FBOs"). FBOs in effect operate a large service station at an airport, providing maintenance, food, and fuel to general aviation customers (such as owners of corporate aircraft, private airplanes, and crop dusters). The demand for general aviation fuel is small compared to that for gasoline, making it uneconomic for many refineries to produce the fuel. Accordingly, there are relatively few marketers of general aviation fuel, who for the most part obtain supply from their own refineries. The FTC observed that Chevron and Texaco were among only a few marketers of general aviation fuel in the western and southeastern United States. To eliminate the possibility of unilateral or coordinated anticompetitive effects post-merger, the FTC required the merging firms to divest Texaco's general aviation business to a third party.[99]

E. Lubricating Oils

The FTC alleged anticompetitive effects in markets for lubricating oils in three cases.[100] Two were remedied with divestitures. Concerns over potential anticompetitive effects in the market for jet turbine oil in Exxon/Mobil were eliminated with the divestiture of Exxon's jet turbine oil business. The assets to be divested included an exclusive perpetual license to certain Exxon jet turbine oil patents, other intellectual property, research and testing equipment, and Exxon's jet turbine oil manufacturing plant.[101] In Shell/Pennzoil-Quaker State, the parties were required to divest Pennzoil's 50%

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98 Generally, an entering marketer may secure a supply of gasoline by directly arranging for bulk supply into an area or by purchasing smaller quantities from other firms at terminal racks. The attractiveness of bulk supply to an entrant will depend on, among other things, pipeline and terminal availabilities and whether the entrant has sufficient scale to make bulk supply economic (*e.g.*, meeting minimum size for shipment nominations on pipelines). The attractiveness of purchasing at rack to an entering marketer will depend on the local availability of unbranded gasoline. As noted above, access to retail locations will depend (in the case of new sites) on local real estate and zoning restrictions, and (in the case of converting existing retail outlets) on the willingness of jobbers and open dealers to switch brands.

99 Chevron/Texaco, Analysis to Aid Public Comment.

100 *See* Tables 2-4, 2-5.

101 Exxon/Mobil, Analysis to Aid Public Comment.

interest in a joint venture base oil plant from which Pennzoil obtained a substantial part of its paraffinic base oil needs.[102] Pennzoil had supplemented this source with a long-term supply agreement with Exxon/Mobil, which had become effective as a result of the FTC's order remedying concerns arising in the market for in paraffinic base oil in the Exxon/Mobil transaction (discussed below). The Shell/Pennzoil-Quaker State order prevented the respondents from increasing the volumes taken under this supply contract, because a significant increase could unduly increase concentration.[103]

In Exxon/Mobil, the FTC relied on remedial means other than divestiture to resolve concerns in the market for paraffinic base oil. The FTC required ExxonMobil to enter into long-term agreements with not more than three firms to supply 12 MBD of base oil from the merged firm's three refineries in the Gulf Coast area. ExxonMobil was also required to modify terms in a Mobil purchase contract with another base oil producer so as to relinquish control over the latter firm's production. While a refinery divestiture, rather than supply agreements, might allow a buyer to make any capital investments or expansions it might choose, a refinery divestiture was not necessary to maintain competition in the market for paraffinic base oil in this matter. The FTC noted that there was a trend toward use of higher-grade base oils, which are replaced less often in lubricating uses. As a result, the demand for base oils was likely to fall, making the need for capacity expansion less significant.

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[102] Paraffinic base oil is a refined product that is the primary component in passenger car motor oil, heavy duty engine oil, automatic transmission fluid, and other lubricating products.

[103] Shell/Pennzoil-Quaker State, Analysis to Aid Public Comment.

Table 2-1 – FTC Merger Enforcement Actions in the Petroleum Industry

Firms (Year)*	Legal Cite
Mobil/Marathon (1981)	Federal Trade Commission v. Mobil Corp. and Mobil Oil Corp., C81-2473 (N.D. Ohio 1981).
Gulf/Cities Service (1982)	Federal Trade Commission v. Gulf Oil Corp., C82-2131 (D.D.C. 1982).
Texaco/Getty (1984)	Texaco, Inc. and Getty Oil Company, 104 F.T.C. 241 (1984).
Chevron/Gulf (1984)	Chevron Corp. and Gulf Corp., 104 F.T.C. 597 (1984).
Conoco/Asamera (1986)	Federal Trade Commission v. E.I. du Pont de Nemours and Co. and Conoco, Inc., File No. 881-0120.
Pacific Resources/Shell (1987)	Pacific Resources, Inc., 111 F.T.C. 322 (1988).
Sun/Atlantic (1988)	Sun Company, Inc., 111 F.T.C. 570 (1989).
Shell/Texaco (1997)	Shell Oil Company and Texaco, Inc., 125 F.T.C. 769 (1998).
BP/Amoco (1998)	British Petroleum Company p.l.c. and Amoco Corporation, 127 F.T.C. 515 (1999).
Exxon/Mobil (1999)	Exxon Corporation and Mobil Corporation, Dkt. C-3907 (January 2001).
BP/ARCO (2000)	BP Amoco plc and Atlantic Richfield Company, Dkt. C-3938 (August 2000).
Chevron/Texaco (2001)	Chevron Corporation and Texaco, Inc., Dkt. C-4023 (January 2002).
Valero/UDS (2001)	Valero Energy Corp. and Ultramar Diamond Shamrock, Dkt. C-4031 (February 2002).
Phillips/Conoco (2002)	Phillips Petroleum Company and Conoco, Inc., Dkt. C-4058 (February 2003).
Shell/Pennzoil-Quaker State (2002)	Shell Oil Company and Pennzoil-Quaker State Company, Dkt. C-4059 (November 2002).

Source: Compiled from FTC complaints, orders, and analyses to aid public comment.

Note: *The year cited in the left-hand column is the year in which the merger was proposed and most of the FTC activity occurred; in some cases, a consent order was not final until a later calendar year.

Table 2-2 – Summary of Remedies Relating to Crude Oil Obtained by FTC Action

Product Market	Resolved by Termination of Merger	Resolved by Divestiture	Resolved by Other Means
Bidding for crude oil exploration rights		BP/ARCO (2000)	
Production and sale of ANS crude oil		BP/ARCO (2000)	
Purchase of crude oil	Conoco/Asamera (1986)		
Transport of crude oil		Chevron/Gulf (1984) Exxon/Mobil (1999) BP/ARCO (2000) Chevron/Texaco (2001)	Texaco/Getty (1984), requirement to supply crude oil and grant crude pipeline access to former Getty customers under specified terms. Shell/Texaco (1997), 10 year extension of supply agreement.

Source: Compiled from FTC complaints, orders, and analyses to aid public comment.

Note: The year cited is the year in which the merger was proposed and most of the FTC activity occurred; in some cases, the consent order was not final until a later calendar year.

Table 2-3 – Summary of Remedies Relating to Refined Light Petroleum Products Obtained by FTC Action

Product Market	Resolved by Termination of Merger	Resolved by Divestiture	Resolved by Other Means
Bulk supply of light products by refineries and/or pipelines	Gulf/Cities Service (1982) Conoco/Asamera (1986)	Texaco/Getty (1984) Chevron/Gulf (1984) Shell/Texaco (1997) Exxon/Mobil (1999) Chevron/Texaco (2001) Valero/UDS (2001) Phillips/Conoco (2002)	
Terminaling of light products	Pacific Resources/Shell (1987)	Sun/Atlantic (1988) Shell/Texaco (1997) BP/Amoco (1998) Exxon/Mobil (1999) Chevron/Texaco (2001) Phillips/Conoco (2002)	Exxon/Mobil (1999), continuation of competitor access to wharf under potential competition theory. Phillips/Conoco (2002), terminal throughput agreement with option to buy 50% undivided interest in Phillips terminal.
Marketing of light products	Mobil/Marathon (1981) Gulf/Cities Service (1982) Pacific Resources/Shell (1987)	Texaco/Getty (1984) Chevron/Gulf (1984) Sun/Atlantic (1988) Shell/Texaco (1997) BP/Amoco (1998) Exxon/Mobil (1999) Chevron/Texaco (2001)	BP/Amoco (1988), jobbers and open dealers given option to cancel without penalty.

Source: Compiled from FTC complaints, orders, and analyses to aid public comment.

Note: The year cited is the year in which the merger was proposed and most of the FTC activity occurred; in some cases, the consent order was not final until a later calendar year.

Table 2-4 – Summary of Remedies Relating to Lubricating Oils Obtained by FTC Action

Product Market	Resolved by Termination of Merger	Resolved by Divestiture	Resolved by Other Means
Jet turbine oil		Exxon/Mobil (1999)	
Paraffinic base oil		Shell/Pennzoil Quaker State (2002)	Exxon/Mobil (1999), relinquishment of contractual control over Valero's base oil production, long-term supply agreements at formula prices. Shell/ Pennzoil Quaker State (2002), volume of input supply contract frozen.

Source: Compiled from FTC complaints, orders, and analyses to aid public comment.

Note: The year cited is the year in which the merger was proposed and most of the FTC activity occurred; in some cases, the consent order was not final until a later calendar year.

Table 2-5 – FTC Enforcement Actions in the Petroleum Industry 1981-2003

Firms (Year)*	Markets Affected	Theory of Anti-competitive Effects	Concentration (HHI)	FTC Enforcement Action
Mobil/ Marathon[1] (1981)	Wholesale marketing of gasoline and middle distillates in various markets in the Great Lakes area	Unilateral / Coordinated[2]	Not publicly available[3]	FTC sought preliminary injunction, but before hearings were held Mobil withdrew tender offer as a result of injunction in a separate, private litigation
Gulf/Cities Service[4] (1982)	1. Wholesale distribution of gasoline in various areas in the East and Southeast	Coordinated	Not publicly available	Gulf withdrew its tender offer after the FTC obtained a temporary restraining order prior to a preliminary injunction hearing
	2. Manufacture and sale of kerosene jet fuel in PADDs I and III and parts thereof	Coordinated	Not publicly available	As above
	3. Pipeline transportation of refined products into the Mid Atlantic and Northeast	Unilateral[5]	Not publicly available	As above
Texaco/Getty[6] (1984)	1. Refining of light products in the Northeast[7]	Unilateral	Not publicly available	Divestiture of Texaco refinery at Westville, NJ
	2. Pipeline transportation of light products into the Northeast	Unilateral / Coordinated[8]	Not publicly available	Texaco required to support all Colonial pipeline expansions for ten years
	3. Pipeline transportation of light products into Colorado	Unilateral / Coordinated[9]	Not publicly available	Divestiture of either Texaco pipeline interest or Getty refining interests
	4. Wholesale distribution of gasoline and middle distillates in various parts of the Northeast	Coordinated	Not publicly available	Divestiture of Getty marketing assets in the Northeast, and a Texaco terminal in Maryland
	5. Sale and transport of heavy crude oil in California	Unilateral[10]	Not publicly available	Texaco required to supply crude oil and crude pipeline access to former Getty customers under specified terms
Chevron/ Gulf[11] (1984)	1. Bulk supply of kerosene jet fuel in parts of PADDs I and III and the West Indies and Caribbean islands	Coordinated	Not publicly available	Divestiture of one of two specified Gulf refineries in Texas and Louisiana.

Table 2-5 *(continued)*

Firms (Year)*	Markets Affected	Theory of Anti-competitive Effects	Concentration (HHI)	FTC Enforcement Action
	2. Transport of light products to the inland Southeast	Coordinated[12]	Not publicly available	Divestiture of Gulf's interest in the Colonial Pipeline
	3. Wholesale distribution of gasoline and middle distillates in numerous markets in West Virginia and the South	Coordinated	Not publicly available	Divestiture of all Gulf marketing assets in six states and parts of South Carolina
	4. Transport of crude oil from West Texas/New Mexico	Unilateral / Coordinated[13]	Not publicly available	Divestiture of Gulf interests in specified crude oil pipelines, including 51% of Gulf's interest in the West Texas Gulf Pipeline Company
Conoco/ Asamera[14] (1986)	1. Bulk supply (from refineries and pipelines) of gasoline and other light products to eastern Colorado	Unilateral[15] / Coordinated	Not publicly available	FTC voted to seek preliminary injunction; parties abandoned the transaction
	2. Purchasing of crude oil in the Denver-Julesberg Basin of northeastern Colorado	Unilateral	Not publicly available	As above
PRI/Shell[16] (1987)	1. Terminaling and marketing of light petroleum products on the individual island of Oahu, HI	Unilateral / Coordinated	Not publicly available	FTC won preliminary injunction in U.S. District Court; prior approval required for future acquisitions
	2. Terminaling and marketing of light petroleum products on the individual islands of Maui, Hawaii, and Kauai in the state of Hawaii (potential competition)	Unilateral / Coordinated	Not publicly available	As above
Sun/Atlantic[17] (1988)	Terminaling and marketing of light products in Williamsport, PA and Binghamton, NY	Coordinated	Not publicly available	Divestiture of terminal and associated owned retail outlets in each area
Shell/Texaco[18] (1997)	1a. Refining of gasoline for the Puget Sound area	Unilateral / Coordinated	Post-merger 3812 Change 1318	Divestiture of Shell refinery at Anacortes, WA; Shell jobbers and dealers given option to contract with purchaser
	1b. Refining of jet fuel for the Puget Sound area	Unilateral / Coordinated	Post-merger 5248 Change 481	As above
	2a. Refining of gasoline for the Pacific Northwest	Unilateral / Coordinated	Post-merger 2896 Change 561	As above

Table 2-5 *(continued)*

Firms (Year)*	Markets Affected	Theory of Anti-competitive Effects	Concentration (HHI)	FTC Enforcement Action
	2b. Refining of jet fuel for the Pacific Northwest	Unilateral / Coordinated	Post-merger 2503 Change 258	As above
	3. Refining of "CARB" gasoline for California	Unilateral / Coordinated	Post-merger 1635 Change 154	As above
	4. Transportation of undiluted heavy crude oil to San Francisco Bay area for refining of asphalt	Unilateral[19]	Not applicable	Ten year extension of crude oil supply agreement.
	5. Pipeline transportation of refined light products to the inland Southeast U.S.	Coordinated[20]	Pre-merger >1800	Divestiture of either party's pipeline interest
	6. CARB gasoline marketing in San Diego County, California	Coordinated	Post-merger 1815 Change 250	Divestiture to a single entity of retail outlets with specified individual and combined volume
	7. Terminaling and marketing of gasoline and diesel fuel on the island of Oahu, Hawaii	Coordinated	Post-merger 2160 Change 267	Divestiture of either Shell's or Texaco's terminal and associated retail outlets
BP/ Amoco[21] (1998)	1. Terminaling of gasoline and other light products in nine separate metropolitan areas, mostly in the Southeast U.S.	Coordinated	Post-merger range >1500 - >3600 Change >100	Divestiture of a terminal in each geographic market
	2. Wholesale sale of gasoline in thirty cities or metropolitan areas in the Southeast U.S. and parts of Ohio and Pennsylvania	Coordinated	Post-merger range >1400->1800 Change >100	Divestiture of BP's or Amoco's owned retail outlets in eight geographic areas; in all 30 areas jobbers and open dealers given option to cancel without penalty
Exxon/ Mobil[22] (1999)	1. Gasoline marketing in at least 39 metro areas in the Northeast (Maine to New York) and Mid-Atlantic (New Jersey to Virginia) regions of the U.S.	Unilateral / Coordinated	Post-merger range from 1000-1800 Change >100 to Post-merger >1800 Change >50 (all inferred)	Divestiture of all Exxon (Mobil) owned outlets and assignment of agreements in the Northeast (Mid-Atlantic) region
	2. Gasoline marketing in five metro areas of Texas	Unilateral / Coordinated	Post-merger range from 1000-1800 Change >100 to Post-merger >1800 Change >50 (all inferred)	Divestiture of Mobil's retail outlets and supply agreements

Table 2-5 *(continued)*

Firms (Year)*	Markets Affected	Theory of Anti-competitive Effects	Concentration (HHI)	FTC Enforcement Action
	3. Gasoline marketing in Arizona (potential competition)	Coordinated	Not applicable	Termination of Exxon's option to repurchase retail outlets previously sold to Tosco
	4. Refining and marketing of "CARB" gasoline in California	Unilateral / Coordinated	Post-merger 1699 Change 171 (measured by refining capacity)	Divestiture of Exxon's refinery at Benicia, CA, and all of Exxon's marketing assets in CA, including assignment to the refinery buyer of supply agreements for 275 outlets
	5. Refining of Navy jet fuel on the west coast	Unilateral / Coordinated	Post merger >1800 (inferred) Change >50 (inferred)	As above
	6. Terminaling of light products in Boston, MA and Washington, DC areas	Unilateral / Coordinated	Post merger >1800 (inferred) Change >50 (inferred)	Divestiture of a Mobil terminal in each area
	7. Terminaling of light products in Norfolk, VA area.	Unilateral / Coordinated	Post merger >1800 (inferred)	Continuation of competitor access to wharf
	8. Transportation of light products to the Inland Southeast	Coordinated[23]	Post-merger >1800 (inferred)	Divestiture of either party's pipeline interest
	9. Transportation of Crude Oil from the Alaska North Slope	Coordinated[24]	Post-merger >1800 (inferred) Change >50 (inferred)	Divestiture of Mobil's 3% interest in TAPS
	10. Terminaling and gasoline marketing assets on Guam	Unilateral / Coordinated	Post-merger 7400 Change 2800	Divestiture of Exxon's terminal and retail assets on the island
	11. Paraffinic base oil refining and marketing in the U.S. and Canada	Unilateral / Coordinated	Post-merger range 1000 to 1800 (inferred) Change >100 (inferred)	Relinquishment of contractual control over Valero's base oil production; long term supply agreements at formula prices for volume of base oil equal to Mobil's U.S. production

Table 2-5 *(continued)*

Firms (Year)*	Markets Affected	Theory of Anti-competitive Effects	Concentration (HHI)	FTC Enforcement Action
	12. Refining and marketing of jet turbine oil worldwide	Unilateral[25]	Pre-merger >5625	Divestiture of Exxon jet turbine oil manufacturing facility at Bayway, NJ, with related patent licenses and intellectual property
BP/ARCO[26] (2000)	1. Production and sale of Alaska North Slope ("ANS") crude oil	Unilateral[27]	Post-merger >5476 Change 2640	FTC filed in federal District Court, then reached consent; divestiture of all of ARCO's Alaska assets[28]
	2. Bidding for ANS crude oil exploration rights in Alaska	Unilateral[29]	Post-merger >1800 (inferred) Change >50 (inferred)	As above
	3. Transportation of ANS crude oil on the Trans-Alaska Pipeline System	Unilateral / Coordinated[30]	Post-merger >5600 Change 2200	As above
	4. Future commercialization of ANS natural gas (potential competition)	Unilateral / Coordinated[31]	Not applicable	As above
	5. Crude oil transportation and storage services at Cushing, Oklahoma	Unilateral[32]	Post-merger >1849 for storage >2401 for pipelines >9025 for trading services Changes >50 (inferred)	Divestiture of all of ARCO's pipeline interests and storage assets related to Cushing
Chevron/ Texaco[33] (2001)	1. Gasoline marketing in numerous separate markets in 23 western and southern states	Coordinated	Post-merger range from 1000-1800 Change >100 to Post merger >1800 Change >50 (all inferred)	Divestiture (to Shell, the other owner of Equilon) of Texaco's interests in the Equilon and Motiva joint ventures (including Equilon's interests in the Explorer and Delta Pipelines)
	2. Marketing of CARB gasoline in California	Unilateral / Coordinated	Post-merger range >2000 Change >50	As above

Table 2-5 *(continued)*

Firms (Year)*	Markets Affected	Theory of Anti-competitive Effects	Concentration (HHI)	FTC Enforcement Action
	3. Refining and bulk supply of CARB gasoline for California	Unilateral / Coordinated	Post-merger 2000 Change 500	As above
	4. Refining and bulk supply of gasoline and jet fuel in the Pacific Northwest	Coordinated	Post-merger > 2000 Change > 600	As above
	5. Refining and bulk supply of RFG II gasoline for the St. Louis metropolitan area	Coordinated[34]	Post-merger > 5000 Change > 1600	As above
	6. Terminaling of gasoline and other light products in various geographic markets in California, Arizona, Hawaii, Mississippi, and Texas	Unilateral / Coordinated	Post-merger range >2000 Change >300	As above
	7. Crude oil transportation via pipeline from California's San Joaquin Valley	Coordinated	Post-merger > 3300 Change >800	As above
	8. Crude oil transportation from the offshore Eastern Gulf of Mexico	Unilateral[35]	Post-merger >1800 (inferred) Change >50 (inferred)	As above
	9. Natural gas transportation from certain parts of the Central Gulf of Mexico offshore area	Unilateral / Coordinated[36]	Post-merger >1800 (inferred) Change >50 (inferred)	Divestiture of Texaco's 33% interest in the Discovery Gas Transmission System
	10. Fractionation of natural gas liquids at Mont Belvieu, Texas	Unilateral / Coordinated[37]	Not publicly available	Divestiture of Texaco's minority interest in the Enterprise fractionator
	11. Marketing of aviation fuels to general aviation in the Southeast U.S.	Unilateral / Coordinated	Post-merger > 1900 Change > 250	Divestiture of Texaco's general aviation business to an up-front buyer
	12. Marketing of aviation fuels to general aviation in the western U.S.	Unilateral / Coordinated	Post-merger > 3400 Change > 1600	As above
Valero/UDS [38] (2001)	1. Refining and Bulk Supply of CARB 2 gasoline for northern California	Unilateral / Coordinated	Post-merger > 2700 Change > 750	Divestiture of UDS's refinery at Avon, CA, bulk gasoline supply contracts, and 70 owned and operated retail outlets

Table 2-5 *(continued)*

Firms (Year)*	Markets Affected	Theory of Anti-competitive Effects	Concentration (HHI)	FTC Enforcement Action
	2. Refining and Bulk Supply of CARB 3 gasoline for northern California	Unilateral / Coordinated	Post-merger > 3050 Change >1050	As above
	3. Refining and Bulk Supply of CARB 2 gasoline for state of California	Coordinated	Post-merger > 1750 Change > 325	As above
	4. Refining and Bulk Supply of CARB 3 gasoline for state of California	Coordinated	Post-merger >1850 Change > 390	As above
Phillips/ Conoco[39] (2002)	1. Bulk supply (via refining or pipeline) of light petroleum products in eastern Colorado	Coordinated	Post-merger > 2600 Change > 500	Divestiture of Conoco refinery in Denver and all of Phillips marketing assets in eastern Colorado
	2. Bulk supply of light petroleum products in northern Utah	Coordinated	Post-merger > 2100 Change > 300	Divestiture of Phillips refinery in Salt Lake City and all of Phillips marketing assets in northern Utah
	3. Terminaling services in the Spokane, Washington area	Unilateral / Coordinated	Post-merger 5000 Change > 1600	Divestiture of Phillips' terminal at Spokane
	4. Terminaling services for light products in the Wichita, Kansas area	Unilateral / Coordinated	Post-merger > 3600 Change > 750	Terminal throughput agreement with option to buy 50% undivided interest in Phillips terminal
	5. Bulk supply of propane in southern Missouri	Unilateral / Coordinated	Post-merger 3700 Change > 1200	Divestiture of Phillips' propane business at Jefferson City and E. St. Louis; contracts giving buyer nondiscriminatory access to market at Conway, KS
	6. Bulk supply of propane in St. Louis	Unilateral / Coordinated	Post-merger > 7700 Change > 1000	As above
	7. Bulk supply of propane in southern Illinois	Unilateral / Coordinated	Post-merger > 7700 Change > 1000	As above
	8. Natural gas gathering by pipeline in certain parts of western Texas and southeastern New Mexico (Permian Basin)	Unilateral[40]	Not publicly available	Divestiture of Conoco's gas gathering assets in each area

Table 2-5 *(continued)*

Firms (Year)*	Markets Affected	Theory of Anti-competitive Effects	Concentration (HHI)	FTC Enforcement Action
	9. Fractionation of natural gas liquids at Mont Belvieu, Texas	Unilateral / Coordinated[41]	Not publicly available	Prohibitions on transfers of competitive information; voting requirements for capacity expansion
Shell/Pennzoil Quaker State[42] (2002)	Refining and marketing of paraffinic base oil in U.S. and Canada	Unilateral / Coordinated	Post-merger >2300 Change >700	Divestiture of Pennzoil interest in lube oil joint venture; Pennzoil sourcing of lube oil from third party lube oil refiner frozen at current level

Source: Compiled from FTC complaints, orders, and analyses to aid public comment.

Note:
*Table 2-5 chronologically lists enforcement actions, beginning with the FTC's first challenge of a major petroleum merger in 1981. The year cited is the year in which the merger was proposed and most of the FTC activity occurred; in some cases, a consent order was not final until a later calendar year.
[1] Mobil/Marathon (1981), Memorandum of Points and Authorities in Support of the Federal Trade Commission's Complaint for Temporary Restraining Order and for Preliminary Injunction ("Mobil/Marathon Complaint Memorandum") 6, 26-27. 1982 Merger Report.

[2] While the theories of anticompetitive effects were not always clearly articulated in the earliest petroleum merger investigations, a careful reading of the complaint and accompanying materials suggests the type of effects the investigators had in mind. The classifications of theories for these early cases listed in Table 2-5 are therefore based in part on the authors' interpretation of the complaints, court documents, and staff case memoranda. In the case of Mobil and Marathon, the merger would "enhance Mobil's market power" in the relevant markets by "doubling and tripling its share," (Mobil/Marathon Complaint Memorandum 26, 29) suggesting a likelihood of unilateral anticompetitive effects, and that it would increase concentration in already concentrated markets and remove a firm that had tended to act as a maverick, pricing aggressively and selling large volumes to independent retailers (Mobil/Marathon Complaint Memorandum 29-30) – pointing toward a theory of coordinated effects.

[3] The Complaint alleged that the firms' combined shares of wholesale gasoline sales exceeded 24.5% in eighteen SMSAs, reaching 44.0% in one city and 49.4% in another. While HHIs were not calculated at that time, the parties' contribution to HHI (that is, the sum of their squared shares) can be calculated from the market share data given (Mobil/Marathon Complaint Memorandum 27, Table 1). The parties' pre-merger contribution to HHI ranged between 500 and 1,000 for ten of the eighteen SMSAs and exceeded 1,000 for another three.

[4] Gulf/Cities Service (1982), Complaint for a Temporary Restraining Order and Preliminary Injunction Pursuant to Section 13(b) of the FTC Act ("Gulf/Cities Service Complaint"), ¶¶ 19-22. 1982 Merger Report.

[5] Gulf and Cities Service owned 16.78% and 13.98%, respectively, of Colonial Pipeline. Since the merged firm's share would exceed 25%, it would be able to unilaterally block future pipeline expansion under the pipeline's rules. Gulf/Cities Service Complaint ¶ 19.

[6] Texaco/Getty (1984), Complaint ¶¶ 15-59.

[7] At this time pipeline transport from the Gulf Coast was not considered to be in the relevant market for "the manufacture of refined light products." Texaco/Getty (1984), Complaint ¶¶ 19-21.

[8] Texaco owned 14.3% of Colonial Pipeline, "the dominant means of transporting additional refined light products into the Northeast region, supplying approximately 36.9 percent of total consumption . . . in 1982." Getty owned 100% of the Getty Eastern Products Pipeline. Texaco/Getty (1984), Complaint ¶¶ 33-35.

[9] Texaco owned 40% of the Wyco Pipeline, one of four pipelines delivering refined product to Colorado, while Getty owned 50% of the Chase Pipeline. Texaco/Getty (1984), Complaint ¶¶ 29-31.

Table 2-5 *(continued)*

[10] Both Texaco and Getty owned refineries and proprietary pipeline systems in the relevant market. While Texaco produced less heavy crude oil than it could refine, Getty produced more than it could refine on the West Coast. The Complaint alleged that the merger was "likely to increase Texaco's incentives and ability to deny non-integrated refiners heavy crude oil and access to proprietary pipelines." Texaco/Getty (1984), Complaint ¶¶ 50-57.

[11] Chevron/Gulf (1984), Complaint ¶¶ 15-41.

[12] Gulf owned the largest share, 16.78%, of Colonial Pipeline, while Chevron owned the second largest share, 27.13%, of Plantation Pipeline, Colonial's only direct competitor. Chevron/Gulf (1984), Complaint ¶¶ 25-26.

[13] Chevron owned a proprietary pipeline running from the West Texas/New Mexico producing area to El Paso, while Gulf owned the largest share of the West Texas Gulf Pipeline running from the producing area to the Gulf Coast and the MidValley Pipeline at Longview, TX. Chevron/Gulf (1984), Complaint ¶¶ 38-39.

[14] Conoco/Asamera (1986), Complaint that the Commission voted to pursue.

[15] The Preliminary Injunction Complaint in Conoco/Asamera alleged that the merger would create a dominant firm in the relevant markets. Conoco/Asamera (1986), Complaint that the Commission voted to pursue ¶ 15.

[16] PRI/Shell (1987), Complaint ¶¶ 6-12.

[17] Sun/Atlantic (1988), Complaint and Order.

[18] Shell/Texaco (1997), Complaint ¶¶ 10-37; Analysis of Proposed Consent Order to Aid Public Comment.

[19] The Texaco heated pipeline was the only pipeline supplying undiluted heavy crude oil to the San Francisco Bay area, where Shell and a competitor refined asphalt. Shell/Texaco (1997), Complaint ¶ 15.

[20] Shell owned 24% of Plantation Pipeline and Texaco owned 14% of Colonial Pipeline. Shell/Texaco (1997), Complaint ¶ 32.

[21] BP/Amoco (1998), Complaint ¶¶ 8-21; Analysis of Proposed Consent Order to Aid Public Comment.

[22] Exxon/Mobil (1999), Complaint ¶¶ 8-54; Analysis of Proposed Consent Order to Aid Public Comment.

[23] Exxon owned 49% of Plantation Pipeline and Mobil owned 11% of Colonial Pipeline. Exxon/Mobil (1999), Complaint ¶ 13.

[24] Exxon and Mobil owned 20% and 3%, respectively, of the Trans-Alaska Pipeline System (TAPS), the only means of transporting Alaskan North Slope (ANS) crude oil to the port facilities at Valdez, AK. Exxon/Mobil (1999), Complaint ¶ 14.

[25] Exxon and Mobil together accounted for 75% of worldwide sales, and 90% of worldwide sales to commercial airlines. Exxon/Mobil (1999), Analysis of Proposed Consent Order to Aid Public Comment.

[26] BP/ARCO (2000), Complaint ¶¶ 10-66; Analysis of Proposed Consent Order to Aid Public Comment.

[27] BP had a 44% share of ANS crude oil production at that time, while ARCO had a 30% share, implying that their contribution to the HHI was 2,836. Their contribution to the post-merger HHI would have been 5476. BP/ARCO (2000), Analysis of Proposed Consent Order to Aid Public Comment.

[28] The ARCO Alaska assets divested included crude oil exploration and production assets, 22% interest in TAPS, and specialized tanker ships. BP/ARCO (2000), Analysis of Proposed Consent Order to Aid Public Comment.

[29] BP and ARCO together won 60% of the Alaska state lease auctions during the 1990s, while the top four bidders won 75%. BP/ARCO (2000), Analysis of Proposed Consent Order to Aid Public Comment.

Table 2-5 *(continued)*

[30] BP (50%) and ARCO (22%) both held interests in TAPS. Their contribution to the HHI would have been 2,984 pre-merger and 5,184 post-merger. There were five other owners of TAPS; Exxon held 20% (*see* note 24 *supra*), and the four others' shares are not publicly available; including Exxon and assigning the four other firms equal shares yields a lower bound for the HHI of 3,400 pre-merger or of 5,600 post-merger. BP/ARCO (2000), Analysis of Proposed Consent Order to Aid Public Comment.

[31] The FTC alleged that BP Amoco, ARCO, and Exxon Mobil were the only three companies that held "sufficiently large volumes of gas reserves to have the potential to develop those reserves for significant commercial use." BP/ARCO (2000), Analysis of Proposed Consent Order to Aid Public Comment.

[32] BP and ARCO together accounted for 43% of storage capacity, 49% of pipeline capacity, and 95% of trading services at Cushing. BP/ARCO (2000), Analysis of Proposed Consent Order to Aid Public Comment.

[33] Chevron/Texaco (2001), Complaint ¶¶ 12-57; Analysis of Proposed Consent Order to Aid Public Comment.

[34] Chevron held a 17% interest in Explorer Pipeline, and Texaco and Equilon (Texaco's joint venture with Shell) together held 36%. Explorer is the largest pipeline supplying bulk Phase II Reformulated Gasoline (RFG II) to St. Louis; at the time, Equilon also had a long-term contract that gave it control of much of the output of a local St. Louis area refinery. Chevron/Texaco (2001), Analysis of Proposed Consent Order to Aid Public Comment.

[35] Equilon owned 100% of Delta, and Chevron owned 50% of Cypress; these two pipelines were the only means of transporting crude from the Eastern Gulf of Mexico to on-shore terminals. Chevron/Texaco (2001), Analysis of Proposed Consent Order to Aid Public Comment.

[36] Texaco owned 33% of the Discovery Gas Transmission System; Chevron and its affiliate Dynegy together owned 77% of the Venice Gathering System, one of only two other pipeline systems for transporting natural gas from this area. Chevron/Texaco (2001), Analysis of Proposed Consent Order to Aid Public Comment.

[37] Chevron owned 26% of Dynegy, which held large interests in two of the four fractionators in the market, and had representation on Dynegy's Board of Directors; Texaco held a minority interest in a third. The merger might have led to the sharing of competitively sensitive information and might also have permitted the merged firm to exercise unilateral market power. Chevron/Texaco (2001), Analysis of Proposed Consent Order to Aid Public Comment.

[38] Valero/UDS (2001), Complaint ¶¶ 13-21; Analysis of Proposed Consent Order to Aid Public Comment.

[39] Phillips/Conoco (2002), Complaint ¶¶ 8-135; Analysis of Proposed Consent Order to Aid Public Comment.

[40] Phillips owned 30% of Duke Energy Field Services (DEFS); DEFS and Conoco were the only gatherers in the Permian Basin. Phillips/Conoco (2002), Complaint ¶¶ 69-71.

[41] Phillips owned 30% of DEFS, with representation on its Board of Directors; DEFS held an interest in two of the four fractionators in the market. Conoco partially owned and operated a third, Gulf Coast Fractionators. The merger would have given the combined firm veto power over significant expansion projects and might have led to the sharing of competitively sensitive information. Phillips/Conoco (2002), Complaint ¶¶ 76-79.

[42] Shell/Pennzoil-Quaker State (2002), Complaint, Analysis of Proposed Consent Order to Aid Public Comment.

Table 2-6 – FTC Horizontal Merger Investigations Post-Merger HHI and Change in HHI (Delta) for Oil Markets FY 1996 through FY 2003 (Enforced/Closed)

	Change in HHI (Delta)								
Post-Merger HHI	0 - 99	100 - 199	200 - 299	300 - 499	500 - 799	800 - 1,199	1,200 - 2,499	2,500 +	TOTAL
0 - 1,399	0/9	0/8	0/3	0/0	0/0	0/0	0/0	0/0	0/20
1,400 - 1,599	0/3	7/6	8/2	4/0	0/0	0/0	0/0	0/0	19/11
1,600 - 1,799	0/2	10/3	10/1	13/2	3/1	0/0	0/0	0/0	36/9
1,800 - 2,399	1/5	5/5	10/4	27/4	34/4	1/0	0/0	0/0	78/22
2,400 - 2,999	0/0	1/0	0/0	4/0	13/3	12/2	0/0	0/0	30/5
3,000 - 3,999	0/0	1/0	1/0	1/0	3/0	11/1	4/0	0/0	21/1
4,000 - 4,999	0/0	0/0	1/0	0/0	0/0	0/0	0/0	0/0	1/0
5,000 - 6,999	0/0	0/0	2/0	0/0	1/0	0/0	6/0	2/0	11/0
7,000 +	0/0	0/0	0/0	0/0	1/0	2/0	1/0	8/0	12/0
TOTAL	1/19	24/22	32/10	49/6	55/8	26/3	11/0	10/0	208/68

Source: From Table 3.3 in Federal Trade Commission, *Horizontal Merger Investigation Data, Fiscal Years 1996-2003* (Feb. 2, 2004). Additional details for this report were extracted from contemporaneous Commission staff memoranda written at the time of each investigation to advise the Commission on its enforcement decision.

Chapter 3

Industry Overview

The significance of mergers and divestitures in the petroleum industry over the past two decades can be better understood in light of trends in demand for petroleum products, industry expenditures, and financial indicators. This chapter provides an historical overview of these factors, beginning, in Section I, with price and output trends in crude oil and refined products. Section II follows with a review of industry capital expenditures, and Section III reviews indicia of industry profitability and margins. Section IV reviews technological change and productivity trends in the industry.

The following points summarize the findings of this chapter:

- Foreign production of crude oil increased by 36% between 1985 and 2003, while U.S. crude oil production fell by the same percentage over that same period. Nonetheless, the United States remains a major crude oil producer, ranking behind only Saudi Arabia and Russia in national production in 2003. As domestic crude oil production has declined, foreign crude oil has come to represent a greater percentage of all crude oil used by U.S. refiners, increasing from about 25% of all crude oil used in 1985 to 63% in 2003.

- U.S. consumption of refined petroleum products grew on average about 1% per year between 1985 and 2003, or about 27% over the entire period. U.S. refinery production has generally kept pace with increases in demand, meeting 93% of annual U.S. demand on average. Nevertheless, imports of refined petroleum products have increased somewhat in recent years and are expected to become much more important in the future.

- Real prices for crude oil have remained low compared to the peak prices of the late 1970s and early 1980s, although there have been some significant yearly fluctuations. Average annual crude oil prices have increased each year since 2001, and crude oil prices have increased sharply during the first four months of 2004, achieving some of the highest nominal levels ever. Despite these significant increases in nominal crude oil prices during the first four months of 2004, real crude oil prices remain below the record highs reached during the first six years of the 1980s.

- Refined product prices have largely reflected crude oil prices throughout the past two decades. Despite recent large increases in nominal gasoline prices during early 2004 accompanying sharp crude oil price increases, the average real price of gasoline in the United States remains below the peak prices of the early 1980s. Federal and state excise taxes on gasoline have generally increased since the early 1980s.

- Expenditures for crude oil exploration dominate annual capital expenditures by the petroleum industry. Capital expenditures by U.S. firms for domestic crude oil exploration have generally been increasing in recent years from the relatively low levels of the late 1980s and early 1990s.
- Despite improvement in recent years, since the 1980s the average returns on equity for leading domestic oil companies have been below the average returns on equity of other S&P industrial companies. The domestic return on investment for each industry segment has not matched the levels of the 1980s, although (with the exception of pipelines) it has improved in recent years.
- Overall rates of return on investment for leading U.S. petroleum companies generally have been greater on foreign investments than on domestic investments, although these rates of return converged in 1998 and remained approximately equal through 2002 (the last year for which EIA data are available). Domestic refinery and marketing margins both have been relatively low, and marketing margins in particular have been relatively stable.
- The petroleum industry has seen moderate but steady increases in productivity in recent decades. Technological advances in petroleum exploration and extraction contributed to significant decreases in real crude oil finding costs from the late 1970s until the early 1990s; this downward trend gave way to relatively constant (or, in the case of domestic offshore production, somewhat increasing) real finding costs.
- A number of regulatory and policy developments have affected the industry since the mid-1980s. For example, environmental mandates requiring new fuel specifications have sometimes affected the alternative sources of refined product available during supply disruptions.

I. Price and Output Trends

A. Crude Oil

Production. The steady decline in domestic crude oil production over the last 20 years is among the most important industry developments. Figure 3-1 summarizes these trends. Domestic crude oil output fell by 36% between 1985 and 2003, after maintaining more or less steady levels since the late 1970s. U.S. field production of crude oil averaged 8,971 thousand barrels per day ("MBD") in 1985 but slipped each year to an average of 5,752 MBD by 2003. As domestic crude oil production has declined, foreign crude oil has come to represent a greater percentage of all crude oil used by domestic refiners. Foreign crude oil increased from about 25% of all crude oil used in 1985 to 63% of all crude oil used in 2003.[1] Domestic offshore

[1] The Strategic Petroleum Reserve ("SPR") has not accounted for more than about 1% of total imports since 1988, and did not account for any imports during the first 10 months of 2003. *See* EIA, *Petroleum*

production rose from 1,250 MBD in 1985 to 2,028 MBD in 2002, but was not enough to offset the decline in domestic onshore production from 7,722 to 3,789 MBD. Alaskan production fell sharply from its peak of 2,017 MBD in 1988 to 984 MBD by 2002. [2]

Foreign crude oil production increased from 45,011 MBD in 1985 to 63,759 MBD in 2003. Annual total world crude oil production increased approximately 29% between 1985 and 2003. Foreign crude oil production made up about 83% of total world production in 1985 and increased to about 92% of total world production by 2003. The United States nonetheless remains a major crude oil producer, ranking behind only Saudi Arabia and Russia in total national production in 2003.[3]

Prices. From 1986 to 2003, crude oil prices remained below the historically high levels attained in the early 1980s. Figure 3-2 shows average wellhead prices in current (nominal) dollars for domestic crude oil [4] and market prices for two important foreign crude oils. [5]

After increasing sharply between 1978 and 1981, crude oil prices declined gradually during the early 1980s but still maintained historically high levels. In late 1985, world and domestic crude oil prices began to fall sharply. This sharp decline followed a decision by Saudi Arabia and other OPEC members to abandon a policy of propping up prices through curtailed production. [6]

From 1987 until 1999, domestic crude oil prices generally stayed within a narrow range of several dollars centered around $15 per barrel. One exception was 1990, when prices exceeded $20 per barrel as a result of the Gulf War. Another was in 1998, when domestic crude oil fell to under $11 per barrel, due to increases of OPEC and world oil supply generally, coupled with weakened demand due to the Asian economic crisis.

In 2000, OPEC production cuts and stronger world demand for crude oil resulted in domestic crude oil prices of over $26 per barrel, a level not seen since the 1980s. Crude oil prices fell somewhat in 2001 due, in part, to weaker demand, particularly in the United States. Prices leveled out in 2002 under pressure from stronger domestic oil demand, low crude oil inventories, turmoil in the Middle East, and, at the end of the year, labor strikes that

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Supply Monthly (Feb. 2004), Table S2. As of May 5, 2004, the SPR held 658.3 million barrels of crude oil. *See* Department of Energy, *Strategic Petroleum Reserve Inventory for May 5, 2004, available at* http://www.spr.doe.gov/reports/dir.htm.

[2] EIA, *Annual Energy Review 2002*, Table 5.2 .

[3] EIA, *International Petroleum Monthly* (Mar. 2004), Tables 4.1 a, b, and c.

[4] Domestic crude oil prices are largely determined by global supply and demand conditions. As with crude oils from other parts of the world, domestic crude oils from different fields vary in specific gravity and level of impurities. Inasmuch as these properties affect refinery yields and costs, there are price differentials for different crude oil types. However, the prices of different crude oil types are highly correlated over time, and examining an average across all domestic crude oils is instructive on general price trends.

[5] EIA, *International Energy Database April 2002*, Table 7.1.

[6] EIA, *Petroleum Chronology of Events 1970 – 2000, available at* http://ww.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/chronology/petroleumchronology2000.htm.

resulted in the near cessation of oil exports from Venezuela. Domestic prices climbed above $28 per barrel in January 2003, reached almost $32 in February preceding the war in Iraq, and then fell to $25 per barrel by September 2003. From September 2003 through April 2004, domestic crude oil prices increased by roughly one dollar per barrel each month to reach $33.21 in April 2004 .[7]

At the time of this Report's writing, EIA had not released data on average crude oil prices beyond April 2004, but it is clear that the U.S. average wellhead price rose considerably in May 2004 before falling in June. On July 12, 2004, WTI, a light, sweet crude oil, traded at $39.50 per barrel. WTI typically trades at $3 to $4 per barrel higher than the U.S. wellhead average reported by EIA and averaged $3.58 more per barrel during 2002 and 2003. Using the historic relationship between WTI crude oil prices and the average wellhead price produces an estimated average wellhead price on July 12 of about $35.75 per barrel.

Using the this relationship between WTI and the average wellhead price in the United States to estimate the average wellhead prices for May and June, the average wellhead price for the first six months of 2004 is about $33.50 per barrel, or slightly more than $32.50 per barrel in 2002 dollars. If these higher crude oil prices persist throughout 2004, average annual crude oil prices could achieve an annual record high (in nominal terms), exceeding the $31.77 annual average crude oil price mark set in 1981. In real terms, however, an annual average real crude oil price of $32.50 per barrel, while the highest in 19 years, would still fall below the average real crude oil costs experienced between 1980 and 1985, when annual real crude oil costs reached as high as $56 per barrel in 2002 dollars.

Thus, despite the sharp escalation of crude oil prices in 2004, the crude oil prices of recent years remain relatively low when compared to those of the first half of the 1980s (expressed in "real" or inflation-adjusted dollars). Domestic crude oil prices are shown in both current and real dollars in Figure 3-3.

B. Refined Petroleum Products

Production. Output of domestically refined products generally experienced moderate growth since the mid-1980s, as Figure 3-4 shows. This sustained period of relatively steady growth reversed a period of declining domestic refined products output between 1978 and 1983. U.S. refinery production has been by far the primary source for domestic refined petroleum products, meeting on average 93% of domestic demand annually. Increases in domestic refinery production generally have kept pace with increases in demand. Nonetheless, refined product imports have increased somewhat in recent years and are

[7] EIA, *Petroleum Marketing Monthly* (July 2004), Table 1. EIA's monthly Domestic First Purchase crude oil prices for April 2004 are preliminary estimates. At the time of publication, Domestic First Purchase crude oil prices for May and June 2004 had not yet been released. Inspection of crude oil prices for West Texas Intermediate ("WTI"), a heavily traded sweet crude oil, indicates that domestic crude oil prices increased in May by between $3.00 and $3.50 per barrel but subsequently declined by as much as $2.25 per barrel in June.

expected to become much more important in the future.[8]

Consumption. Domestic consumption of refined products declined during the late 1970s and early 1980s, largely in response to the high prices during that time. Domestic consumption has since risen; between 1985 and 2003, average daily U.S. consumption of petroleum products increased on average by 1% per year, from 15,726 MBD to 20,044 MBD, for a total increase of 27%.[9]

Figure 3-5 shows consumption trends by type of refined petroleum product. Motor gasoline has been and is by far the most important product, accounting for 49% to 53% of the daily consumption of all petroleum products since 1982. The decline in consumption of residual fuel oil notably contrasts with the generally increasing consumption of other classes of refined products since the mid-1980s.[10] To a large extent, the decline in residual fuel oil consumption, which began in the late 1970s, is attributable to displacement by natural gas and distillates for electricity generation.

Prices. Figure 3-6 summarizes U.S. average retail prices for motor gasoline (excluding taxes), in current and real dollars, between 1978 and 2003. Reflecting events in crude oil markets, this period began with significant price increases between 1978 and 1981, after which gasoline prices gradually decreased in the early to mid-1980s and fell sharply between 1985 and 1986. Significant back-to-back increases occurred in 1989 and 1990, due in large part to increases in the price of crude oil.[11]

The early to mid-1990s were marked by generally flat or slightly declining gasoline prices. An increase in 1996 preceded a period of increased price volatility, which can be seen more easily in the quarterly price data shown in Figure 3-7. Sharp declines in 1998 were followed by several years of increasing prices, with particularly large increases in 2000 and early 2001. Gasoline prices in the second quarter of 2001 rose to $1.18 per gallon (in current dollars, excluding taxes), the highest price level to that time since 1978.[12]

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8 EIA recently predicted that net imports of all refined products would increase from about 13% of U.S. demand in 2002 to 20% by 2025. *See* EIA, *Annual Energy Outlook 2004 with Projections to 2025*, 7 (2004).

9 EIA, *Petroleum Supply Monthly* (Feb. 2004), Table S1. Consumption is approximately equivalent to EIA's definition of Petroleum Products Supplied.

10 Residual fuel oil includes classes of relatively heavy refined products used in, among other things, electric power generation, space heating, vessel bunkering and other industrial purposes. Distillate fuel oils include several grades of diesel and fuel oil products used in, among other things, highway diesel engines and domestic space heating. Jet fuel is used for commercial and military turbojet and turboprop aircraft engines. Liquefied petroleum gases are a variety of gases produced in the refining of crude oil, such as ethane, ethylene, and propane.

11 While the impact of crude oil prices on gasoline prices is widely recognized, it has been alleged that gasoline prices are "sticky downward" – that is, gas prices "go up like rockets" and "come down like feathers" in response to changes in oil prices. For a review of the empirical literature testing this hypothesis, *see* John Geweke, Issues in the "Rockets and Feathers" Gasoline Price Literature, submitted in conjunction with the Federal Trade Commission Conference, *Factors That Affect the Price of Refined Petroleum Products II* (May 8, 2002). This paper indicates there are serious and sometimes fundamental flaws with the studies purporting to show such asymmetric responses.

12 These prices represent national averages for regular gasoline, excluding taxes. State and local taxes

Even at this peak for current prices, real prices remained below the levels experienced in the late 1970s through mid-1980s.[13] After falling through the second half of 2001, gasoline prices jumped dramatically in the second quarter of 2002, then leveled out in the second half of the year with real prices slightly higher than the levels observed from 1991 to 1997. In the first quarter of 2003, prices jumped again, reaching $1.15 per gallon, the second highest current dollar price seen during the period from 1983 to 2003. Prices fell to $1.07 per gallon in the second quarter of 2003, returned to the previous level of $1.15 per gallon in the third quarter and again fell to around $1.06 per gallon in the last quarter of 2003. Retail gasoline prices for the first two months of 2004 increased to $1.17 per gallon. The increased retail gasoline prices during 2004 are largely attributed to the increase in crude oil prices. Beyond higher crude oil costs, additional factors -- such as the switch to the summer gasoline season, unexpected refinery outages on the West Coast and the Gulf Coast, and the January 2004 MTBE bans in Connecticut and New York -- also likely contributed to the higher retail gasoline prices.

EIA monthly retail gasoline price estimates were not available beyond February 2004 at the time of this writing. Based on daily OPIS retail data across 360 areas in the United States, we estimate the average gasoline price to be about $1.35 per gallon for April 2004; using OPIS-based estimates for March and April implies an average of about $1.25 per gallon for the first four months of 2004.[14] Despite the recent, dramatic gasoline price increases, current gasoline prices in real terms remain below prices of the early 1980s (through 1985) and late 1990. Average gasoline prices over the first four months of 2004 more closely resemble the real gasoline prices from the second quarter of 2001.

The prices of distillates, jet fuel and other refined products have exhibited trends similar to gasoline.

Gasoline Taxes. Federal and state excise tax rates on gasoline generally have increased since the early 1980s. The federal rate on gasoline rose from 9 cents per gallon in 1985 to 18.4 cents per gallon by 2001. [15] Although state excise taxes vary widely from state to state, the American Petroleum Institute ("API") estimates that the average state gasoline tax increased from 13 cents per gallon in

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(which vary widely across state and local jurisdictions) plus federal taxes add on average about 50 cents per gallon to the retail prices that consumers pay. In addition, local and regional differences in the wholesale price of gasoline lead to differences from this national average, with some regions paying higher prices than others.

[13] Quality-adjusted real gasoline prices also would take into account the environmental benefits of cleaner product specifications.

[14] Price estimates based on OPIS data exclude taxes. The four-month average is calculated using published EIA average gasoline price data for the months of January and February and OPIS-based estimated retail data for March and April.

[15] Federal Highway Administration, *Highway Statistics 2000*, Tables FE-101A and MF-205, *available at* http://www.fhwa.dot.gov/ohim/hs00/hf.htm. In recent years the federal government also has levied separate taxes to support various petroleum trust funds. The largest of these programs is the Underground Storage Tank Trust Fund, which is funded with a 0.1-cent-per-gallon motor fuel tax. A 5-cents-per-barrel tax on domestic or imported crude oil to finance the Oil Spill Liability Trust Fund expired at the end of 1994. *See also* EIA, *Federal Financial Interventions and Subsidies in Energy Markets 1999: Primary Energy* (1999), Appendix B, Fact Sheets 25 and 26.

1985 to 23.6 cents per gallon in 2002. [16] In addition to excise taxes, API's estimate of state motor fuel taxes includes other applicable taxes such as sales taxes, gross receipts taxes, inspection fees, underground storage tank fees, and other environmental fees. These estimates largely exclude local county and municipal motor fuel taxes and local sales taxes. Though local taxes on motor fuels vary widely, API estimated that these taxes for 2003 averaged approximately 2 cents per gallon nationally. This amounts to an average state tax per gallon of almost 26% in 2001, compared to 14% in 1985.

II. Industry Capital Expenditures

Trends in industry capital expenditures indicate how firms' investment decisions reflect changing market conditions. When broken down by industry segment, capital expenditures also provide a quantitative sense of the relative importance of different industry segments.

A. Domestic Expenditures

Domestic capital expenditures (expenditures within the United States) by industry segment of the U.S. oil industry between 1977 and 2003 are presented in Figures 3-8a and 3-8b.[17] (Figure 3-8a presents the data in current dollars, while Figure 3-8b gives real values in 2002 dollars. This convention is followed in most figures in this section and the text.)

Upstream investment. Upstream investment, which consists of investment in assets associated with the exploration and production of crude oil,[18] accounted for 78% of all domestic investment between 1977 and 2003. Annual upstream investment peaked at over $57 billion (in current dollars) in 1981 before falling to around $12 billion in the late 1980s and early 1990s; this corresponds to a decline from $102 billion in 1981 to about $15 billion in 1992 in real (2002) dollars. Upstream investment has since increased, and has exceeded $38 billion since 2001.

Upstream expenditure. Upstream expenditure (particularly exploration expenditure) is the largest category of investment and has been the most volatile, responding to changes in crude oil prices. During the period of relatively high crude oil prices from 1977 to 1987, the percentage of all industry investments attributable to upstream activities increased to 82%.[19]

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[16] API, *How Much We Pay for Gasoline*, Table 2 (Oct. 2002), *available at* http://api-ec.api.org/filelibrary/howmuchwepay2002.pdf. *See also* API, *Nationwide and State-by-State Motor Fuel Taxes* (July 2003), *available at* http://api-ep.api.org/filelibrary/ACF235.pdf.

[17] Capital expenditure data are obtained through PennWell's survey of virtually all domestic oil companies (including Shell and British Petroleum). These data do not include merger and acquisition expenditures. The calculations in this section treat the following PennWell categories as the petroleum downstream: Refining, Marketing, Crude Oil and Products Pipelines, and Other Transportation. Transport of natural gas and production of petrochemicals are not included.

[18] Upstream investment includes outer continental shelf lease bonuses, which are lump-sum payments (as opposed to royalties) that exploration companies pay to the government for leases in the OCS.

[19] EIA, *Performance of Profiles of Major Energy Producers 2001*, 83. Other factors also contributed to the surge in domestic upstream investment during the 1970s and the early 1980s. As a result of nationalization of privately held reserves and other policies discouraging foreign investment in some oil-producing states outside the U.S., some major oil

Upstream investment also increased between 1995 and 1997 (a period of moderately rising crude oil prices), fell in 1999 as crude oil prices sharply declined in response to the Asia economic crisis, and has since risen again. Exploration investment during 1977-2003 accounted for an average of almost 80% of all upstream investment, with investment in production accounting for most of the rest (the remainder being outer continental shelf ("OCS") lease bonuses).[20]

The relatively large size of exploration expenditures raises an important point: crude oil is exhaustible, and most of the largest private petroleum producers would deplete their current proved reserves in less than 15 years at current rates of production.[21] Motivated by the expectation that crude oil prices will exceed the costs of developing new production, the search for new reserves is therefore essential to maintaining current output levels as well as satisfying additional demand. The depletion of the "easiest" locations has pushed (and will continue to push) exploration further off-shore and to riskier (for U.S. and other western companies) foreign locations, but the resulting increases in exploration and production costs generally have been offset by improvements in exploration and production technology.[22] Geopolitical issues in some foreign areas, such as the Caspian Basin, present additional risks for crude oil exploration and development.[23]

Downstream investment. Domestic downstream investment peaked in 1981 and again in the early 1990s at approximately $10 billion per year ($17 billion (1981) and $13 billion (1991) in 2002 dollars). Downstream investment varied between $7.5 billion and $9 billion between 1995 and 2003, ending

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companies devoted more effort to developing domestic reserves. The then-current tax laws (and high crude oil prices) also encouraged entry into the development of domestic oil and gas resources by firms other than the major oil companies. Those tax laws also generally favored reinvestment of the cash flows, which were strong during this period of high crude oil prices, rather than payouts as shareholder dividends.

[20] PennWell Corporation, *Worldwide Petroleum Industry Outlook*, 147 (18th ed., 2001); *id.* at 145 (17th ed., 2000); *id.* at 126 (7th ed., 1990); *id.* at 78 (3rd ed., 1986). *See also* PennWell, *Special Report: Capital Spending Outlook,* 71; PennWell, *Petroleum Industry Outlook: 2004-2008.*

[21] Dividing company worldwide proved reserves by company worldwide production rates provides an estimate of reserve lifetimes. Using the reserve and production data presented in Chapter 5, estimated lifetimes of major oil company reserves, based on 2001 levels, are as follows: ExxonMobil, 13.3 years; Shell, 11.7 years; ChevronTexaco, 12.2 years; BP, 11.9 years; and ConocoPhillips, 13.8 years. Reserves are not known with certainty and estimates may be revised, sometimes considerably, upon additional analysis. For example, in January 2004 Shell announced it was reducing by 20% (about 3.9 billion barrels) the estimate of its proved gas and natural gas liquid reserves. *See Shell cuts proved reserves by 20 percent,* PETROLEUM NEWS (Jan. 18, 2004) (press release). Shell re-categorized its reserves as a result of completion of new in-depth studies of its reserves. *See also* Shell Oil Company, *Message to staff from Sir Phillip Watts on the re-categorization of proved hydrocarbon reserves* (Jan. 16, 2004) (press release), *available at*

http://www.shell.com/home/Framework?siteId=investor-en&FC3=/investor-en/html/iwgen/news_and_library/press_releases/2004_other/message_from_sir_philip_watts_16012004.html&FC2=/investor-en/html/iwgen/news_and_library/press_releases/2004_other/zzz_lhn.html.

[22] *See* comments of David Montgomery, transcript of Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products II,* 15-16 (May 8, 2002).

[23] EIA, *World Energy "Areas to Watch"* (July 2003), *available at* http://www.eia.doe.gov/emeu/security/hot.html.

at $9 billion. Refining was the most important category in downstream investment, on average accounting for 50% of downstream investment between 1977 and 2003. Marketing and pipelines accounted for 29% and 13%, respectively.[24] Refining investment was also the most variable among the downstream categories.

Increases in refining investments during the early 1990s were particularly notable and were attributable in large part to new environmental requirements, which had their greatest impact on the refining level of the industry. The API estimated that the industry spent approximately $98 billion (in current dollars) on environmental expenditures between 1992 and 2001. This estimate includes capital expenditures, ongoing expenditures for operations, maintenance, administration, research and development, and expenses relating to cleaning up spills and contamination of soil and groundwater. API estimated that about 53% of the industry's environmental expenditures between 1992 and 2001 were related to refining, 18% were related to exploration and crude oil production, 10% involved transportation, and 6% involved marketing activities, while 10% were used for remediation and spills.[25]

Figure 3-9 shows environmental capital expenditures in current and real dollars. Total environmental capital investments peaked at $4.8 billion in current dollars ($5.7 billion in 2002 dollars) in 1993 with the implementation of new product standards for gasoline, improvements to retail station tankage, and other pollution control measures. Refinery environmental investments, which peaked near $3.3 billion in 1992 ($3.9 billion in 2002 dollars) accounted for slightly over half of all environmental investments during the 1990s and almost two-thirds from 1990 to 1995. Refinery environmental investments accounted for about 25% of total domestic refinery capital investment during the 1990s.[26]

B. International Capital Expenditures

Figures 3-10a and 3-10b present data on international (outside the United States) expenditures by U.S. oil companies. As with domestic expenditures, capital expenditures for exploration and crude oil production are the biggest elements in total international expenditures by U.S. firms. On average, upstream investment accounted for 77% of total international expenditures between 1982 and 2003 and 51% of that upstream investment went toward exploration. Refining accounted for 41% and marketing for

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[24] PennWell Corporation, *Worldwide Petroleum Industry Outlook*, *supra* note 20; PennWell, Special Report: Petroleum Industry Outlook, supra note 20.

[25] API, *U.S. Oil and Natural Gas Industry's Environmental Expenditures 1992 - 2001*, Figure 1 (Feb. 20, 2003), *available at* http://api-ec.api.org/filelibrary/FinalEES01.pdf. *See also* API, *Cumulative Impact of Environmental Regulations on the U.S. Petroleum Refining, Transportation and Marketing Industries* (Oct. 1997), *available at* http://api-ep.api.org/filelibrary/Cumulative%20Impact%20of%20Environmental%20Regulation.doc,

[26] This percentage is calculated using data from two different surveys, one done by PennWell and the other by API; these data may not be fully compatible. *See* PennWell Corporation, *Worldwide Petroleum Industry Outlook*, *supra* note 20. *See also* PennWell, *Special Report*, *supra* note 20; and *Petroleum Industry Outlook: 2004-2008*, *supra* note 20; API, *Environmental Expenditures 1992 – 2001*, *supra* note 25, Table 3 and Figure 4; API, *Environmental Expenditures 1990 -1999*, Table 3 and Figure 4.

48% of international downstream capital expenditures by U.S. firms.[27]

As highlighted in the next section on industry profitability, foreign investments proved to be consistently more profitable than domestic investments from the early 1980s until the late 1990s.

After falling in the early 1980s, international expenditures by U.S. firms increased steadily from 1988 to 1997, when total international expenditures on upstream and downstream investments exceeded $30 billion in current dollars ($32 billion in 2002 dollars). This increase reflected a shift of investment away from the United States toward lower-cost areas.[28] Domestic investment by U.S. companies historically has exceeded their international investment, but this difference has been shrinking rapidly, especially in upstream sectors.

III. Industry Rates of Return and Margins

Various demand, supply, and regulatory factors may affect the realization of profits. Industry competitiveness is among these factors and in turn may itself be affected by structural change, including those changes caused by mergers and acquisitions. This section reviews trends in industry rates of return and trends in various price-cost margins.

A. Overall Return on Equity

Under the Financial Reporting System ("FRS"), EIA collects financial and operating data for a group of about 30 major oil companies (hereinafter "FRS companies").[29] The FRS return on equity data provide one index of overall industry profitability. The FRS companies accounted for 46% of U.S. crude oil and natural gas liquids ("NGL") production and 92% of refining capacity in 2001.[30]

The overall rate of return on stockholders' equity (which includes both domestic and foreign returns) of FRS companies between 1977 and 2002 is presented in Figure 3-11. Figure 3-12 presents the same data as five-year averages between 1977 and 2001. The average rate of return for these companies over this time period was 12.6%. For roughly half of the years presented, the industry rate of return on equity was between 10% and 15%. Returns in excess of 15% were earned in 1974 and in 1978 through 1981 and for several years in the later 1990s and 2000. The peak return occurred in 1980.

The industry experienced returns of less than 10% or less for six of the nine years between 1986 and 1994 (in 1992 returns plummeted to almost zero) and for 1998. Returns for 2002 were

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27 *Id.*

28 PennWell, *Worldwide Petroleum Industry Outlook*, 152 (18th ed., 2001)

29 These companies meet the following selection criteria: "at least 1% of U.S. crude oil or natural gas liquids reserves or production, or at least 1% of U.S. natural gas reserves or production, or at least 1% of U.S. crude oil distillation capacity." Their identity varies from year to year, and can be found at EIA, *Companies Reporting to the Financial Reporting System, 1974-2002, available at* http://www.eia.doe.gov/emeu/perfpro/taba1.html.

30 EIA, *Performance Profiles of Major Energy Producers 2001*, Figure 2.

also below 10% in the face of generally weaker crude oil prices, an economic downturn, and, starting in the later part of 2001, the aftermath of the September 11 attacks. Although there are often multiple successive years of increase or decline, petroleum industry return on equity has not exhibited any clear long-term trend. Five-year averages, as shown in Figure 3-12, indicate an increase in petroleum industry return on equity for the most recent period between 1997 and 2001 compared to the three previous five-year periods, but these returns are below levels earned in the late 1970s and early 1980s.

The FRS companies' rate of return on equity has, on average, been less than that for other S&P Industrial companies, including the average over the most recent five-year period. The average return on equity for the S&P industrials was 13.3% over the period from 1973 to 2001. The return for the FRS companies significantly exceeded that of the S&P in times of relatively high crude oil prices, as in the early 1980s and for 2000 and early 2001. Similarly, during times of historically low crude oil prices, such as the late 1980s, early 1990s and 1998, the FRS companies reported lower returns than other industrial companies.

B. Return on Investment by Line of Business for FRS Companies

FRS companies also report separately returns earned on overall domestic and foreign investments, and domestic returns on investment by industry segment**.** As shown in Figures 3-13 and 3-14, the return on foreign assets was consistently higher than that on domestic assets through the mid-1990s. Overall rate of return on investment was relatively high in the late 1970s and early 1980s, declining to lower levels by the mid-1980s. Overall rate of return on investment was relatively stable until the mid-1990s. Since then, return on investment has become more volatile. The FRS companies earned, on average, 10.0% (8.9% for domestic and 12.6% for foreign) on assets over the entire period from 1977 to 2002, but the return declined to 8% (7.2% domestic and 9.6% foreign), on average, for the years following 1988. Profits from foreign assets accounted for 47% of total FRS profits in 2002.[31]

Figures 3-15 and 3-16 demonstrate that total domestic profitability of the FRS firms is driven mostly by profit contributions from crude oil production, which are large relative to those for other segments.[32] In 2000, for example, crude oil production accounted for roughly two-thirds of total

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[31] EIA, *Financial Reporting System Public Data*, Schedule 5210.

[32] The companies report a contribution margin for a particular industry segment. Returns are calculated by dividing that number by net assets assigned to that segment. The net asset figure is calculated by looking at beginning-of–the-year assets and adding current-year investments.

While domestic profitability of the FRS companies as a group is driven mostly by contributions from crude oil production, it is important to recognize that the effect of crude oil prices upon the profits of any individual company in the petroleum industry will vary, depending upon their position in the production of crude oil. For example, refiners with no crude production will not benefit from an increase in crude oil prices, everything else equal. An increase in crude oil prices increases these refiners' costs, and even though they eventually might be able to pass on much of a crude oil price increase in the form of higher refined product prices, quantity demanded will fall somewhat as a result.

domestic profits. According to the EIA, the average return on production assets during 1977 to 2002 was 10%, while the average return on refining and marketing assets was 5.8%, and for pipelines was 10.8%. Since 1988, the return on crude oil production assets has averaged 7.8%, refining and marketing 5.8%, and pipeline assets 7.9%.

Reflecting the variability in crude oil prices, return on investment from domestic crude oil production has been more volatile than return on investment in domestic refining/marketing and domestic pipelines. The profitability of domestic production generally follows the price of crude oil and recently reached a minimum in 1998, then increased sharply with crude oil price increases in 2000.

Profits from the refining and marketing segments comprised approximately one-fifth of domestic profits for the FRS companies in 2000. Return on investment in refining/marketing generally was lower than that for other industry segments during 1977-2002, exceeding 10% in only three years (1988, 1989, and 2001). Refining/marketing returns were particularly low during the early to mid-1990s, falling to below zero in 1992 and near zero in 1995. However, refining/marketing profitability increased each year since 1996 before dropping dramatically in 2002.[33] In 2002 the FRS companies suffered a $2.2 billion loss on domestic refining and marketing operations, a record loss since the beginning of the FRS survey.

Profits from rate-regulated pipelines account for roughly 14% of domestic profits for FRS companies.[34] Return on investment for domestic pipelines declined from relatively high levels during the early 1980s until the early 1990s. Since then pipeline returns on investment have fluctuated within a fairly narrow range. They generally have exhibited much less short-term volatility than returns on crude oil production and on refining/marketing.

C. Margins

EIA also collects data from the FRS companies that allow the calculation of margins between certain prices and cost elements; these margins provide another perspective on petroleum industry profitability.[35] Real gross and net refinery margins, in 2002 dollars, are presented in Figures 3-17 and 3-18. Reported real gross product margins (finished product sales less crude oil costs) have fallen over time, as have refinery operating and marketing costs.[36] Net refinery margins historically have been relatively small compared to product prices, and changes in product prices generally have been

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33 EIA, *Major Energy Producers 2002*, 37.

34 Profits and assets for proprietary pipelines are included in the refining and marketing segment.

35 Unlike rate of return estimates, margins are not affected by capital expenditures or investment levels. In addition, gross margins typically fail to account for changes in any costs besides the major input, and even net margins may not reflect all relevant costs.

36 "Gross margin" is defined as total product revenue less crude oil input into refineries. "Operating costs" consist of refinery energy costs, other refinery expenses, and marketing expenses. "Net margins" are the difference between gross margin and operating costs. These data are not strictly indicative of refinery margins, as they do not distinguish between the refinery and marketing operations of the FRS companies.

associated with much smaller changes in refinery margins. For example, national average gasoline prices (excluding taxes) increased from 76.5 cents per gallon in 1999 to 109.5 cents per gallon in 2000 (an increase of 33 cents per gallon).[37] At the same time, net refinery margins increased from 2.6 cents per gallon (3.4% of price) to 5.3 cents per gallon (4.8% of price). Note that changes in net refinery margins are reflected in returns on investment for domestic refining/marketing. For example, improving net refining margins for 2000 and 2001 were associated with improving returns on investment in refining/marketing for those years; 2002, on the other hand, saw a collapse in net refinery margins, reflected in a negative rate of return in refining/marketing for that year.

"Crack spreads" provide another measure of profitability at the refinery level. The "crack spread" is the price difference between the finished petroleum products at the refinery gate and the price of crude oil. A "3-2-1 crack spread" refers to a hypothetical refinery making two gallons of gasoline and one gallon of diesel for every three gallons of crude oil consumed. Figure 3-19 shows the monthly 3-2-1 crack spread (in current dollars) between June 1986 and October 2003 based on New York Harbor spot prices and the spot price for WTI, an important benchmark crude oil.[38] The crack spread is roughly equivalent to the concept of gross margin for the FRS companies and does not take account of refinery operating costs. Accordingly, FRS gross refinery margins and these crack margins display very similar trends.

The 3-2-1 crack spread has averaged about 9.5 cents per gallon, or 16% of the New York spot price of gasoline, since 1986. The spread in current prices is variable, with no strong apparent trend. After an historically high spike of over 20 cents per gallon in spring 2001, spreads retreated to more typical levels. The spread tends to increase in the summer, reflecting refinery capacity constraints in the face of higher product demand during the driving season. Consequently, refineries typically schedule turnarounds (planned outages for maintenance) during the off-season.

Figure 3-20 shows five-year-average 3-2-1 crack spreads in real 2002 dollars from 1988 through 2002. The real five-year-average crack spread fell 31.4% from the 1988-1992 period to the 1993-1997 period. Between the 1993-1997 and 1998-2002 periods, there was a decline in the five-year-average crack spreads of just 1.3%.

With regard to final distribution, rough estimates of average margins at wholesale and retail can be inferred by inspecting EIA data on nationwide average terminal rack price, DTW price, and average retail price (excluding taxes). "Rack price" is the price paid for gasoline by branded and unbranded

[37] EIA, *Petroleum Marketing Annual 2002*, Table A1.

[38] Though a 3-2-1 crack spread based on New York Harbor and WTI spot prices will be broadly indicative of national trends and averages, crack spreads at actual refineries may differ since input and output slates and associated input costs and output prices vary somewhat across refineries. ("Spot prices" are bulk sales of crude oil and petroleum products for immediate delivery not subject to a longer-term contract.)

distributors, or "jobbers," at refined product terminals for subsequent delivery by tank wagon trucks to service stations. "Terminal rack price" is an important wholesale price, since most gasoline in the United States is distributed by jobbers. In many cases, jobbers distribute gasoline from product terminals to service stations which they own.

Consequently, average retail price minus average rack price approximates a margin that reflects tank wagon delivery costs, labor costs, inventory holding and other costs, plus profits at the jobber and the retail level combined. Figure 3-21 shows that the average retail to rack margin has been within a range of 12 to 14 cents a gallon over the last 9 years, with a possible a slight downward trend since 1998. [39] Figure 3-22 shows that retail to rack margins for 1994 to 1999 averaged 13.6 cents per gallon; the average for 2000 to 2003 was 12.7 cents per gallon.[40]

[39] Wholesale price data from EIA that disaggregate DTW and rack prices are available only from 1994 onward.

[40] One measure of industry performance is the price/marginal cost margin. While marginal costs are often difficult to measure directly, differences between price and average variable costs -- or even differences between prices in successive, vertically-related levels -- may provide some insight on the magnitude of price/marginal cost margins. In recent years, net refinery margins (gross margins minus operating costs) typically have been around 4 cents per gallon at a time when refinery gate prices have varied from about $.50 to $1.20 per gallon. Retail and wholesale margins generally appear only slightly higher. As discussed above, the DTW margin (retail price minus DTW price), which is a proxy for the retail margin, averaged 7.5 cents per gallon between 2000 and 2003. The rack margin (retail price minus rack price), which is a proxy for retail plus wholesale margins, averaged 12.7 cents per gallon over the same period. These price-to-price margins do not include various costs such as delivery, labor, and inventory holding costs, and therefore are larger than the margins over cost earned by jobbers and retailers. In any event, these data suggest that typically price/cost margins at wholesale and retail are small compared to retail price.

Of course, margins for individual sellers may vary from these nationwide averages. For example, retail stations in some rural areas may have lower sales volumes than stations in more densely-populated areas. As a consequence, these stations must charge a higher markup if they are to cover various fixed costs, such as station rent and utilities, and to cover the higher cost of transporting fuel to the station. To the extent that rural areas present few entry impediments, theory would predict that entry would occur until firms earn roughly no economic profit, or that the entire margin was being used to cover the costs of the station, including a normal return on capital. *See* John Umbeck, *A Report on Retail and Wholesale Gasoline Prices in the Miami/Globe and Phoenix Markets*, in *Anticompetitive Practices in the Retail Gasoline Market*, Hearings before the Subcommittee on Antitrust, Monopolies and Business Rights of the Committee on the Judiciary, U. S. Senate (May 6, 1992).

Economists sometimes measure the size of the margins relative to demand elasticity to provide evidence about the behavior of the firms in an industry. Demand elasticity is a measure of how sensitive consumers are to price. If a firm's demand elasticity is low, consumers are relatively insensitive to price, and a single firm would have room to raise price profitably. This is true because a price increase would cause only a limited decrease in sales. A firm low elasticity would then be associated with a relatively big margin.

Since individual firms face more elastic demands than the market demand due to competition from substitute products in the same market, economists sometimes try to draw inferences about the degree of competition in an industry by comparing a firm's margin to the aggregate, market-level demand elasticity. For example, if firm margins are small relative to the market elasticity, then competition from substitute products is likely strong. In the petroleum industry, Bulow *et al.* calculated that the margin (retail price less crude oil cost, excluding taxes) in the Midwest in 2000 was only one-sixth of what it would have been if there were only a single seller in the market, even at the peak of the supply disruption during the spring of that year. They concluded that the competition among the various firms was keeping the price low relative to marginal cost. *See,* Jeremy I. Bulow, et al., *U.S. Midwest Gasoline Pricing and the Spring 2000 Price Spike*, 24 ENERGY J. 121 (2003).

Margins at the retail level alone can be roughly inferred by inspecting the difference between retail prices and average nationwide DTW prices. The DTW price is the price that independent lessee and open retail dealers pay for gasoline delivered to them by their branded company suppliers. The difference between average retail price and average DTW price reflects only costs plus profits at the retail level.[41] Figure 3-21 shows that the average retail-to-DTW margin usually has been within a range of 6 to 8 cents a gallon during the last nine years, with a slight upward trend since 2000. The average retail margin for 1994 to 1999 was 6.8 cents per gallon, increasing to 7.5 cents per gallon for 2000 to 2003.

IV. Technological Change and Productivity Increases

Technological change has affected all segments of the petroleum industry and generally has resulted in moderate but steady increases in productivity in most industry segments in recent decades. Productivity statistics based on units of output per unit of input provide a standard quantitative measure of technological change. The Bureau of Labor Statistics ("BLS") reports productivity measures for the crude oil production, refining, and retailing segments of the petroleum industry. Figure 3-23 shows the growth in labor productivity (output per labor hour) by industry segment from 1959 to 2000. Labor productivity in crude oil production shows a peak in the early 1970s. This is largely the result of labor inputs' being front-loaded into the production process: the peak "productivity" occurred at a time of maximum domestic production, but much of the labor associated with that production occurred when the reserves were first discovered. A more appropriate measure of labor productivity for exploration would define output as the increase in proved reserves per unit of labor, but such productivity data are not available.

Nonetheless, exploration productivity has increased due to more sophisticated methods of locating potential drilling sites and enhanced recovery methods to take oil out of fields previously considered economically "spent." Figure 3-24 presents data on the finding costs per barrel, in real dollars, of "proved" oil.[42] Three- and four-dimensional seismic exploration techniques, horizontal drilling, and new deepwater off-shore technologies are among the advances that contributed to reductions in finding costs during the 1980s, even as reserves in "easier" locations were depleted.[43] Finding costs appear to have reached a plateau in

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41 Since a lessee dealer also pays rent on its retail location to the branded gasoline company, it is possible that some portion of the DTW price represents a rental payment as well. This is not an issue with open dealers, which own their retail locations.

42 Finding costs are the total of acquisition costs of unproven acreage and exploration and development cost. These are divided by the total barrels of oil equivalent (accounting for the discovery of natural gas) to obtain an average finding cost per barrel. Annual finding costs vary widely over time because one year's exploration costs may lead to additions in later years, so data on three-year moving averages are presented.

43 *See* comments of David Montgomery at the Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products II*, 15-16 (May 8, 2002).

the 1990s, but could begin rising (and, in fact, may already be rising for off-shore exploration and production) as companies are forced to extract oil from more difficult or less voluminous sites, further off-shore or in riskier foreign locations.

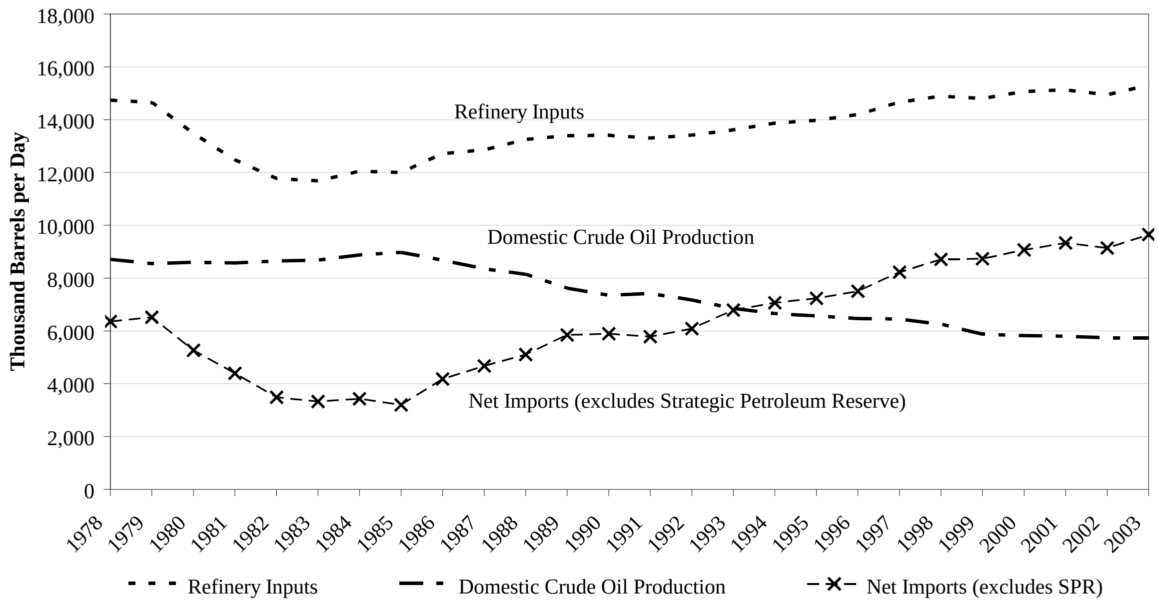
Labor productivity for refining has increased by 4% annually since 1959. Productivity increases have come from increased complexity,[44] the use of more advanced catalysts and refining processes, increased computerization, and larger refineries. The productivity increase is likely underestimated because it does not account for the increased quality of gasoline, resulting in cleaner air and increased protection against other environmental problems such as spills. Much of the increase in labor productivity is the result of the long-term trend toward more capital-intensive refineries that are larger, more complex, and more automated. BLS also calculates multifactor productivity for refining, and these figures show how refineries have become more efficient, taking into account increases in labor, capital, energy, and other material input. As presented in Figure 3-25 below, refinery multifactor productivity has increased at an annual rate of 0.4% since 1949. On average, the multifactor productivity of all manufacturing business has increased at an annual rate of 1.2%.

Labor productivity for gasoline retailing has increased by 3.5% annually, compared with an annual increase of 2% in the productivity in overall non-farm business. Productivity increases likely come from the proliferation of self-serve gas stations, the greater computerization of pumps, and the increase in size of the average service station.[45] As with refining, the productivity increase for gasoline retailing is underestimated because it does not take into account the increased “quality” of stations, such as improvements associated with better tanks to limit environmental contamination.

[44] A more complex refinery contains additional processing units (such as catalytic crackers or alkylation plants) that enable it to obtain higher yields of lighter refined products from any type of crude oil than a less complex refinery.

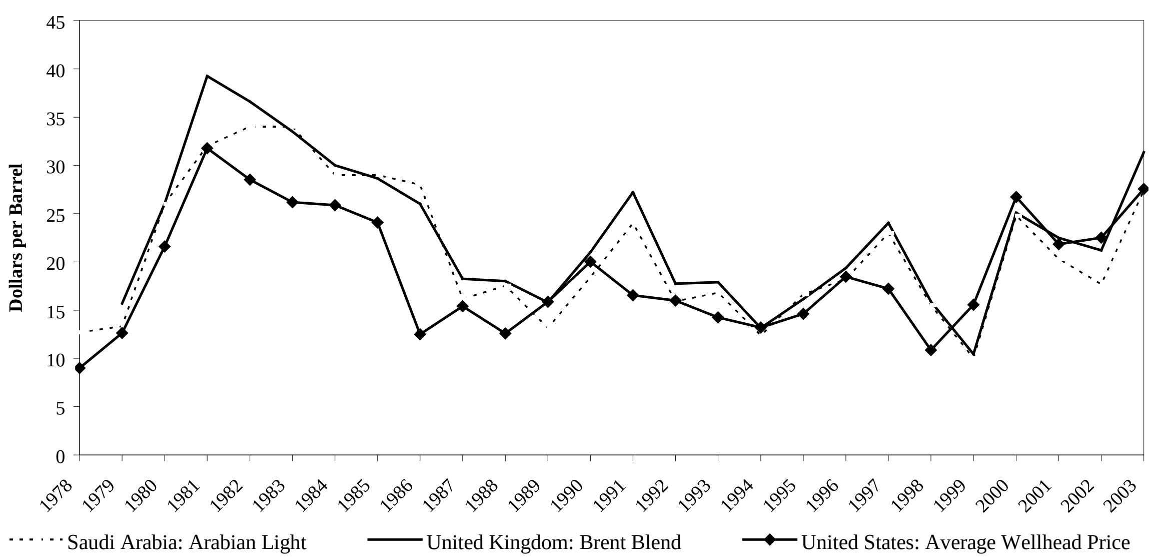
[45] The use of self-serve might be viewed as a reduction in the quality of service at the gas station, resulting in a somewhat lower estimate of productivity. The greater use of computerized pumps and of larger “pumper” stations represents a substitution of capital for labor.

Figure 3-1
Crude Oil Supply and Disposition, 1978-2003



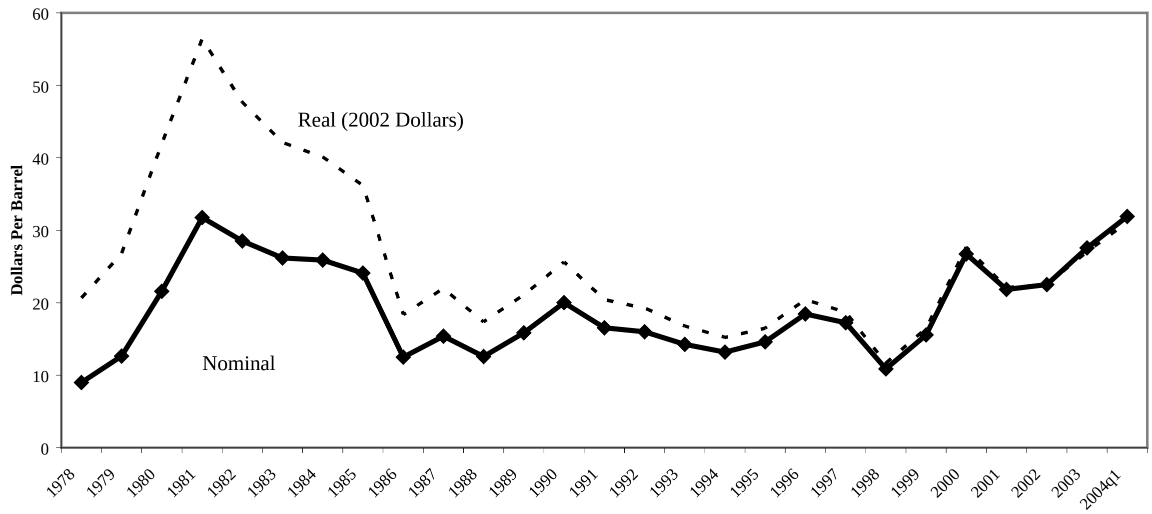
Source: Energy Information Administration, *Petroleum Supply Monthly (February 2004)*, Table S1: Crude Oil and Petroleum Products Overview, 1973 – Present.

Figure 3-2
Selected Crude Oil Prices, Beginning of the Year, 1978-2003



Sources: Energy Information Administration, *Petroleum Marketing Monthly*, Table 1: Crude Oil Prices.
Energy Information Administration, *Annual Energy Review 2002 Files*, Table 11.7: Crude Oil Prices by Selected Type, 1970 -2003.

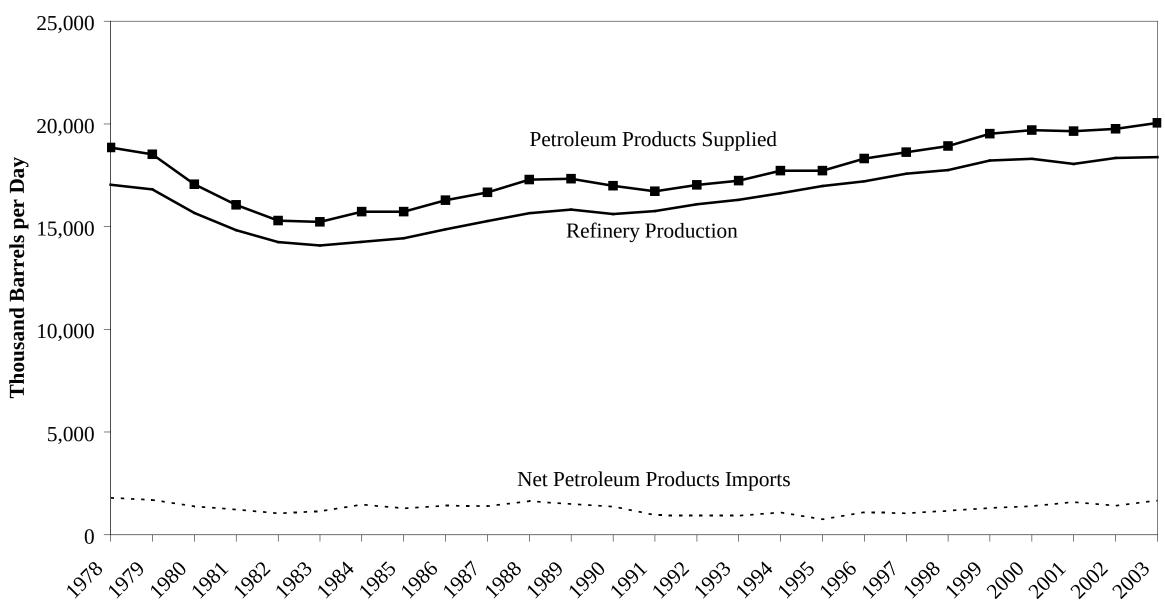
Figure 3-3
United States Average Domestic Crude Oil Prices



Sources: Energy Information Administration, *Petroleum Marketing Monthly March 2004* , Table 1: Crude Oil Prices. Real prices for 1978 2002; Bureau of Economic Analysis, *National Income and Product Accounts Tables* , Table 7.1: Quantity and Price Indexes for Gross Domestic Product.

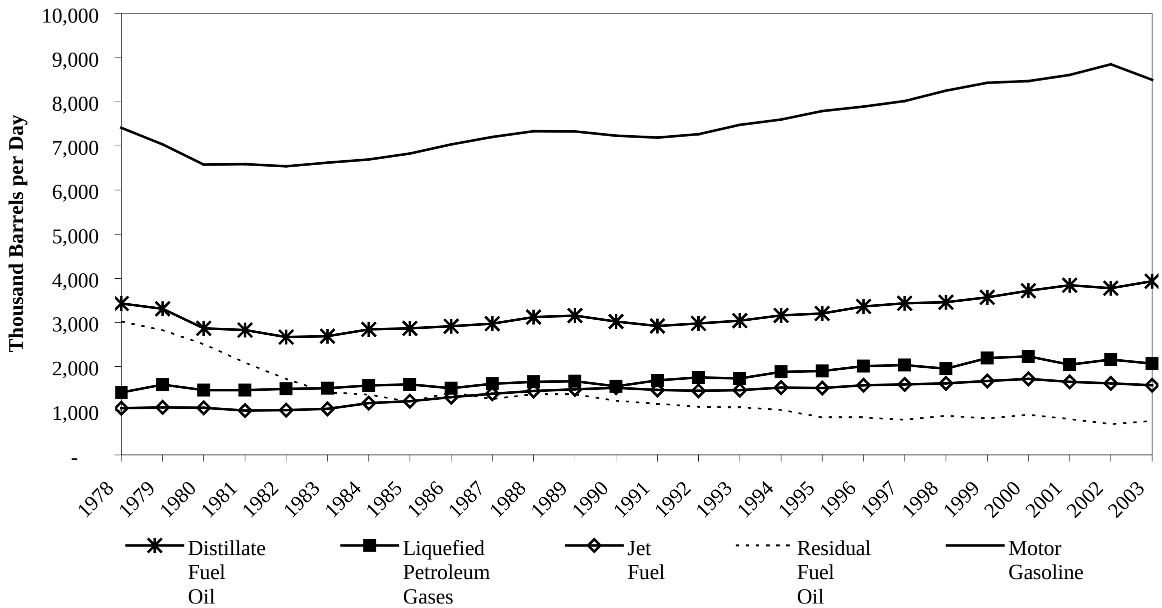
Note: Prices are in chained (2002) dollars, using Gross Domestic Product ("GDP") implicit price deflators. First Quarter 2004 are January and February only.

Figure 3-4
Petroleum Overview, 1978-2003



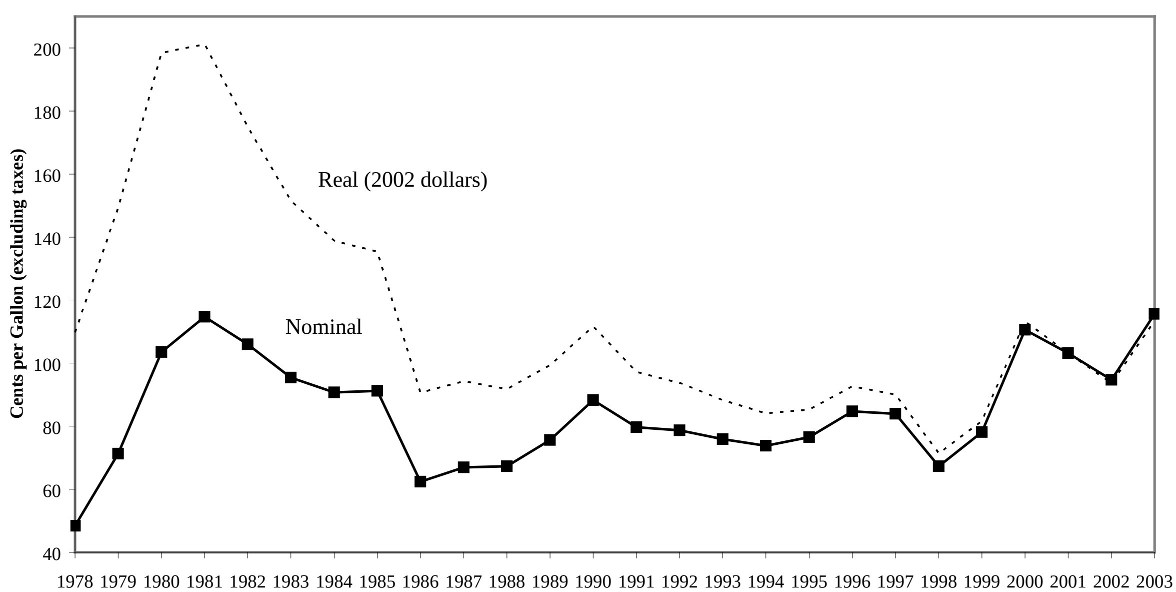
Source: Energy Information Administration, *Petroleum Supply Monthly* , Table S1: Crude Oil and Petroleum Products Overview, 1973 - Present

Figure 3-5
Petroleum Products Supplied (Consumption), 1978 - 2003



Source: Energy Information Administration, *Petroleum Supply Monthly*, Table S4-S7,S9.

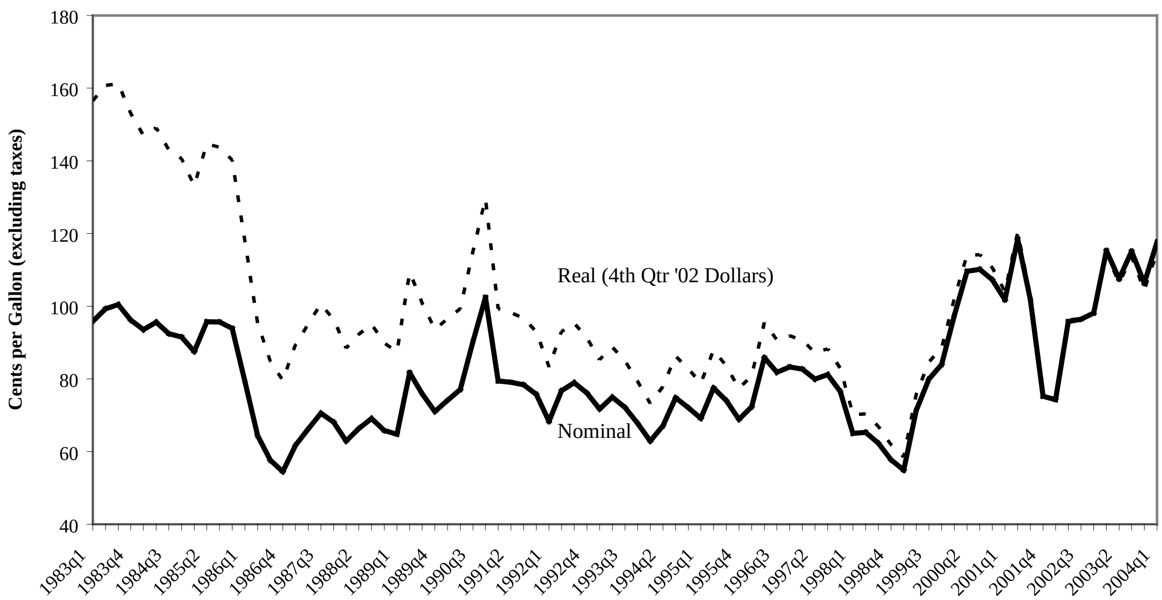
Figure 3-6
U.S. Average Nominal and Real Retail Prices for Motor Gasoline, 1978-2003



Sources: Energy Information Administration, *Petroleum Marketing Monthly February 2004*, Table 2: U.S. Refiner Prices of Petroleum Products to End Users; Bureau of Economic Analysis, *National Income and Product Accounts Tables*, Table 7.1.

Note: Prices are in chained (2002) dollars, using GDP implicit price deflators.

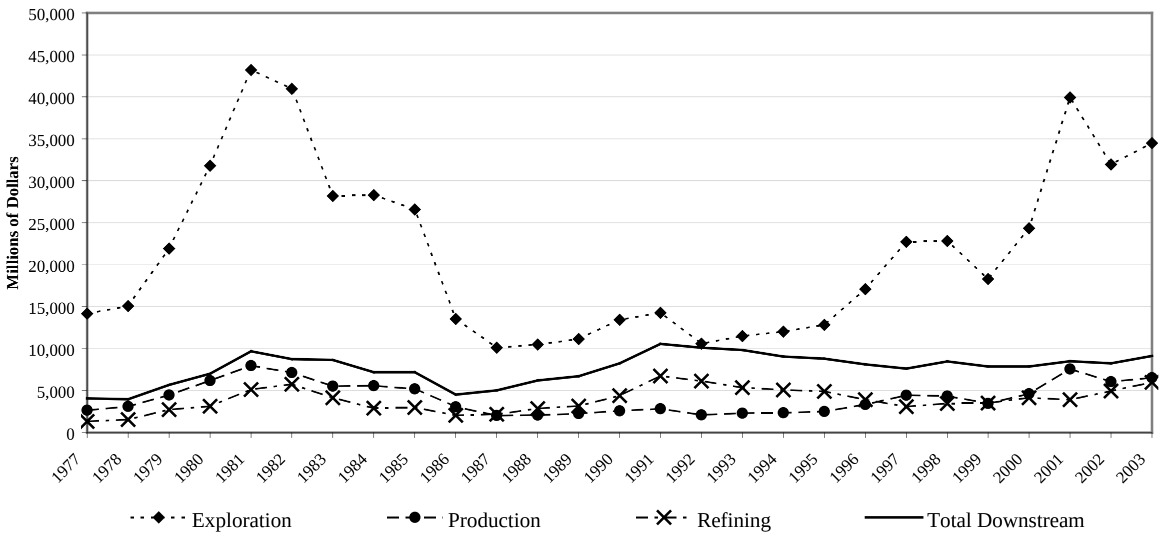
Figure 3-7
U.S. Quarterly Nominal and Real Retail Prices for Motor Gasoline
1983-2004q1



Sources: Energy Information Administration, *Petroleum Marketing Monthly February 2004* , Table 31: Motor Gasoline Prices by Grade, Sales Type, PADD, and State; Bureau of Economic Analysis, *National Income and Product Accounts Tables* , Table 7.1.

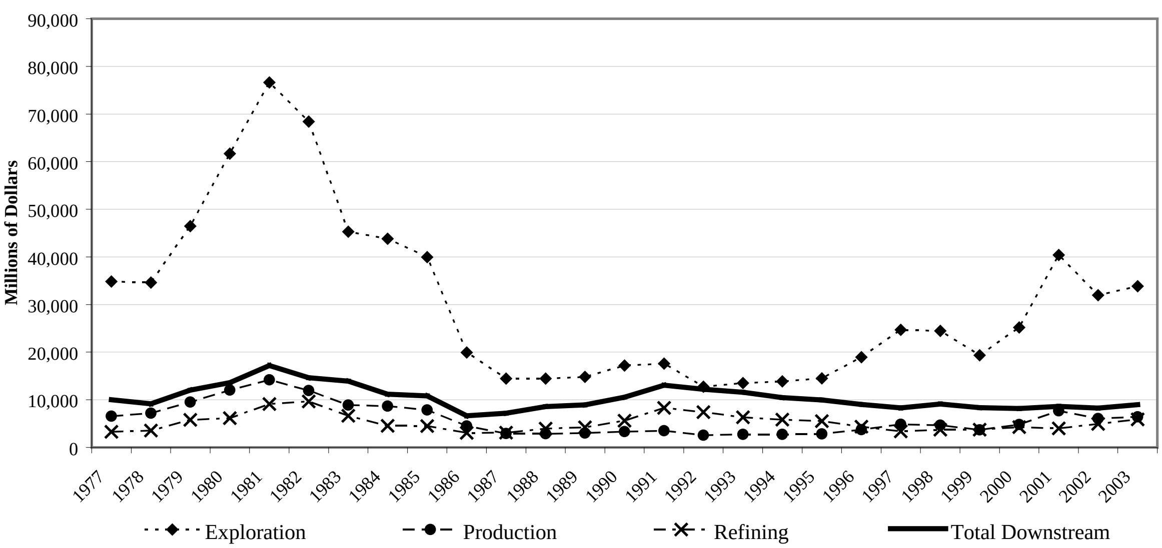
Note: Prices are in chained (4th quarter 2002) dollars, using GDP implicit price deflators. Data following first quarter 2003 are unweighted averages of monthly gasoline price data. First quarter 2004 data include data for January and February only.

Figure 3-8a
Domestic Capital Expenditures



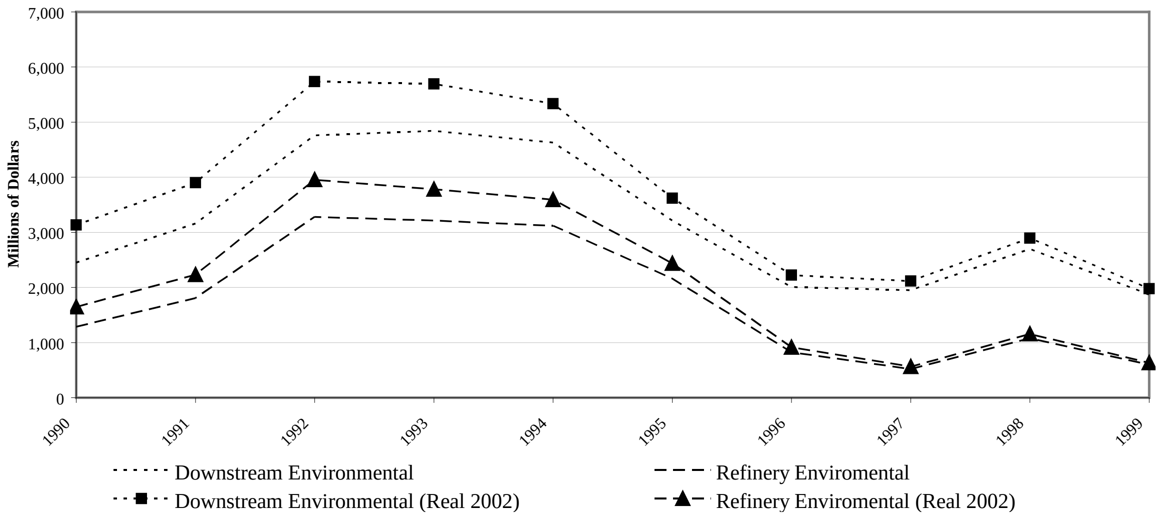
Sources: PennWell Corporation, *Worldwide Petroleum Industry Outlook* , 147 (18th ed. 2001); *Id.* 145 (17th ed. 2000); *Id.* 126 (7th ed. 1990); *Id.* 78 (3rd ed. 1986); PennWell Corporation, "Special Report: Capital Spending Outlook," *Oil & Gas Journal* , 71 (25 March 2002); PennWell Corporation, *Petroleum Industry Outlook: 2004-2008,* (20th ed. 2003).

Figure 3-8b
Domestic Capital Expenditures
2002 Real Dollars



Sources: PennWell Corporation, *Worldwide Petroleum Industry Outlook* , 147 (18th ed. 2001); *Id.* 145 (17th ed. 2000); *Id.* 126 (7th ed. 1990); *Id.* 78 (3rd ed. 1986); PennWell Corporation, "Special Report: Capital Spending Outlook," *Oil & Gas Journal* , 71 (25 March 2002); PennWell Corporation, *Petroleum Industry Outlook: 2004-2008,* (20th ed. 2003).

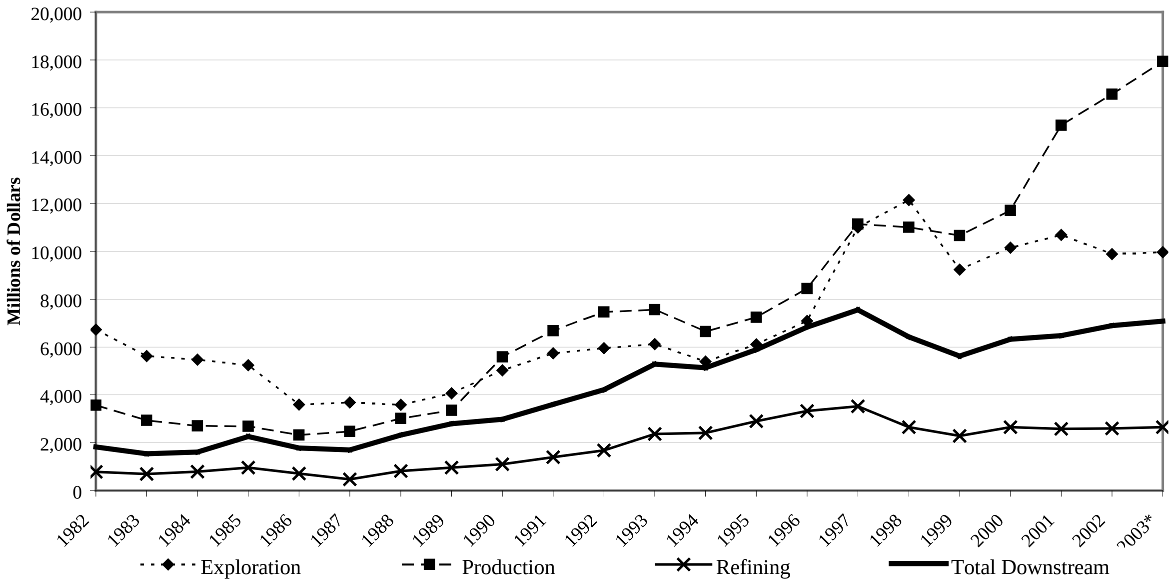
Figure 3-9
Environmental Capital Expenditures



Sources: American Petroleum Institute, *U.S. Petroleum Industry's Environmental Expenditures 1990 -1999* , Table 3 and Figure 4.

Note: API sends surveys to about 800 companies each year, including "all large and mid-size companies, plus a randomly selected group of smaller companies." In 1999, 65 companies completed the survey; see Table 5 of the API report for shares of these participants in various markets. API then extrapolates the data to provide estimates for all domestic firms.

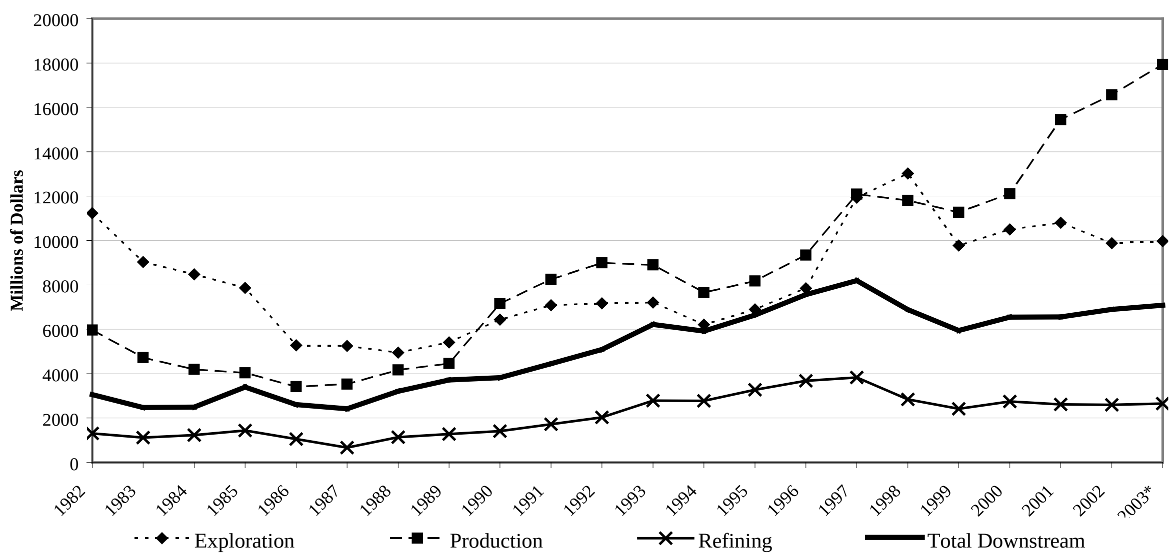
Figure 3-10a
International Capital Expenditures by U.S. Firms



Sources: PennWell Corporation, *Worldwide Petroleum Industry Outlook* , 154 (18th ed. 2001); 128 (17th ed. 2000); 128 (7th ed. 1990); 80 (3d ed. 1986); PennWell Corporation, *Worldwide Petroleum Industry Outlook: 2004-2008 Projection to 2013,* (20th ed. 2003).

Note:Data for 2003 are Pennwell estimates.

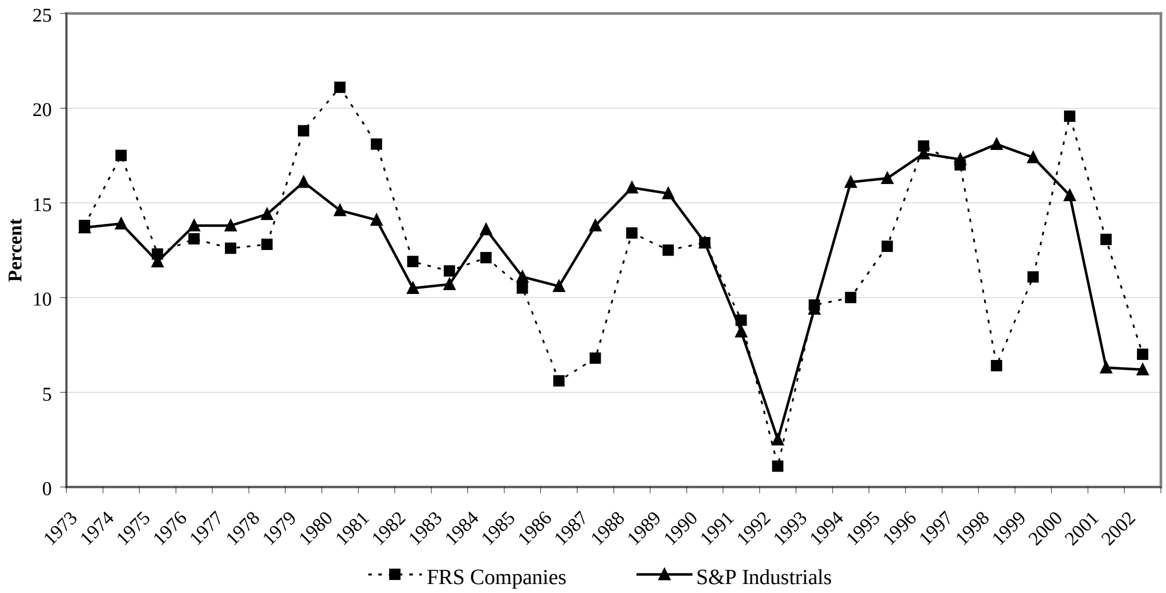
Figure 3-10b
International Capital Expenditures by U.S. Firms
2002 Real Dollars



Sources: PennWell Corporation, *Worldwide Petroleum Industry Outlook* , 154 (18th ed. 2001); 128 (17th ed. 2000); 128 (7th ed. 1990); 80 (3d ed. 1986); PennWell Corporation, *Worldwide Petroleum Industry Outlook: 2004-2008 Projection to 2013,* (20th ed. 2003).

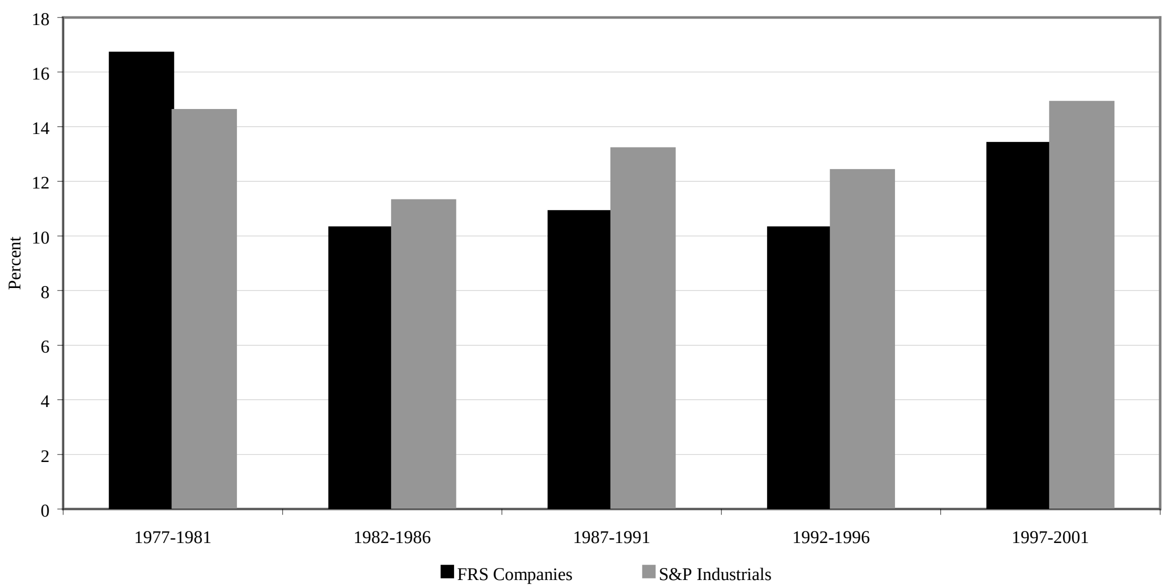
Note: Data for 2003 are Pennwell estimates.

Figure 3-11
Return on Equity for FRS Companies, 1973-2002



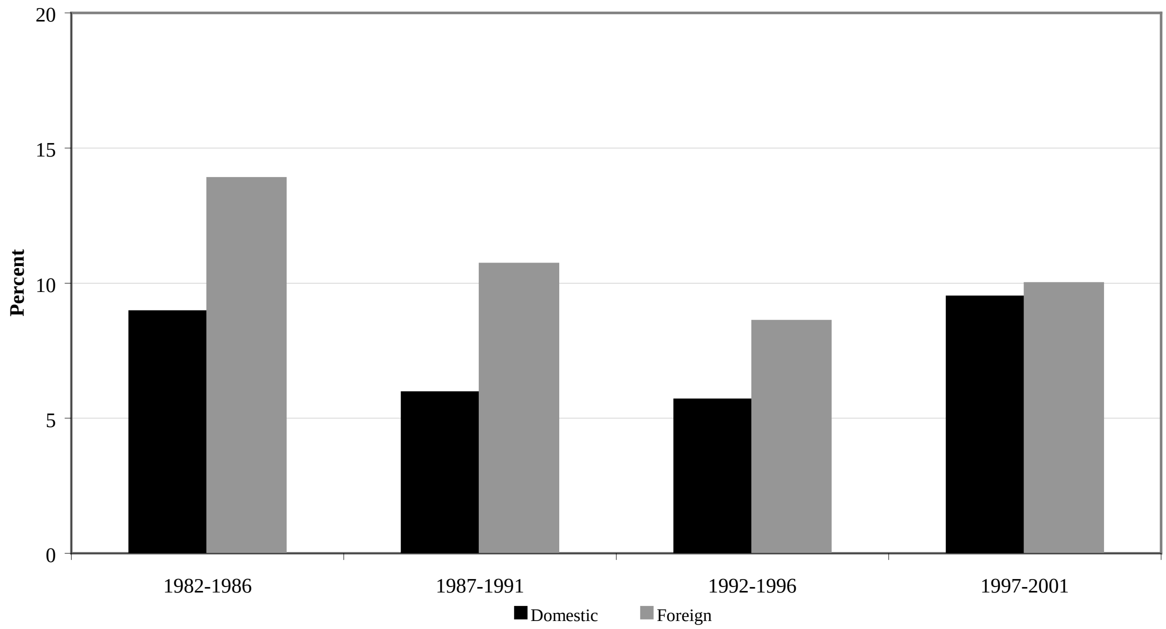
Source: Energy Information Administration, *Performance Profiles of Major Energy Producers 2002* , Figure 3, http://www.eia.doe.gov/emeu/perfpro/perfpro2002.pdf

Figure 3-12
Return on Equity, Five-Year Averages



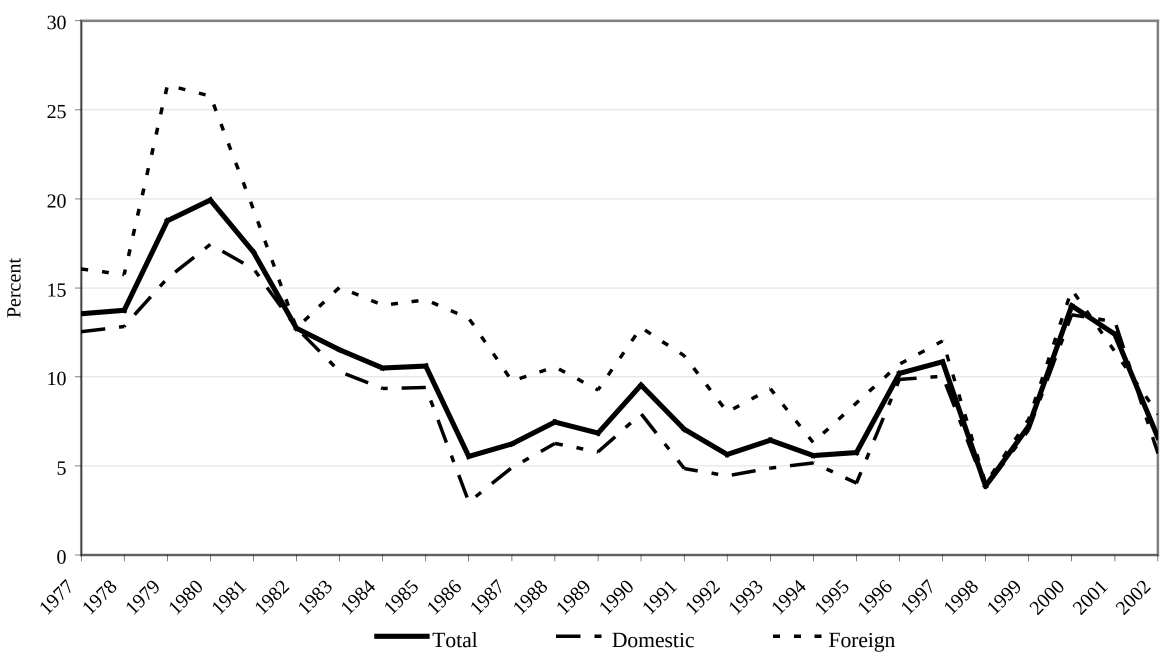
Sources: Energy Information Administration, *Performance Profiles of Major Energy Producers 2002*, Figure 3,http://www.eia.doe.gov/emeu/perfpro/perfpro2002.pdf

Figure 3-13
Return on Investment, Five-Year Averages



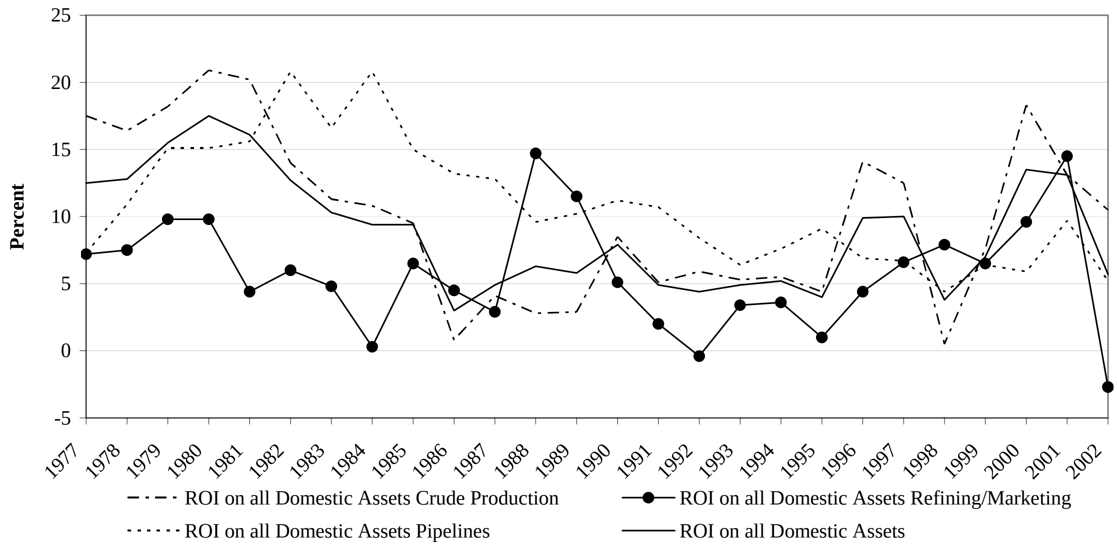
Source: Energy Information Administration, *Financial Reporting System Public Data* , Schedules 5120 and 5210.
http://www.eia.doe.gov/emeu/finance/frsdata.html.

Figure 3-14
Return on Investment



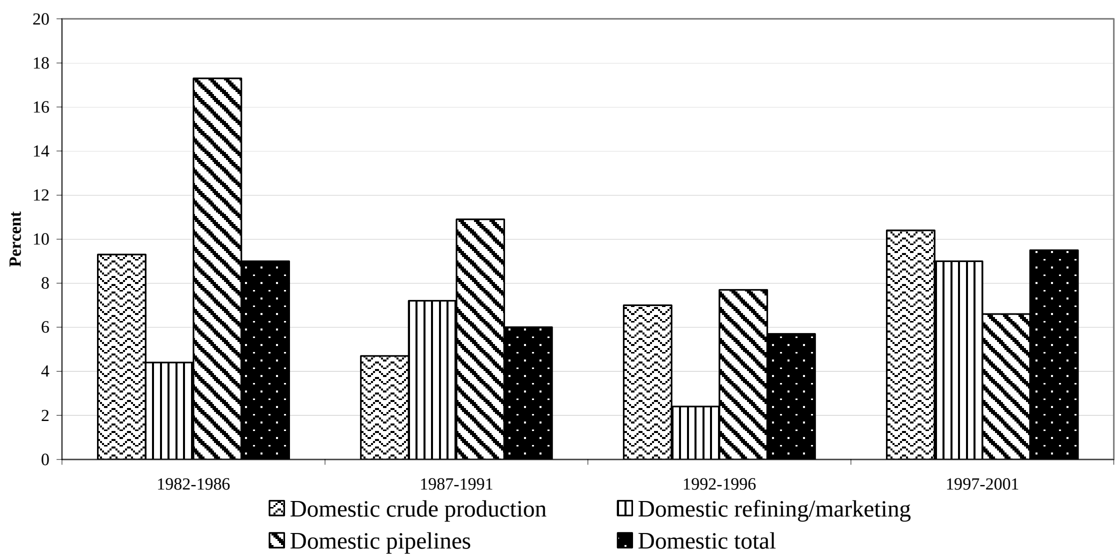
Source: Energy Information Administration, *Financial Reporting System Public Data* , Schedules 5120 and 5210.
http://www.eia.doe.gov/emeu/finance/frsdata.html.

Figure 3-15
Return on Investment by Segment



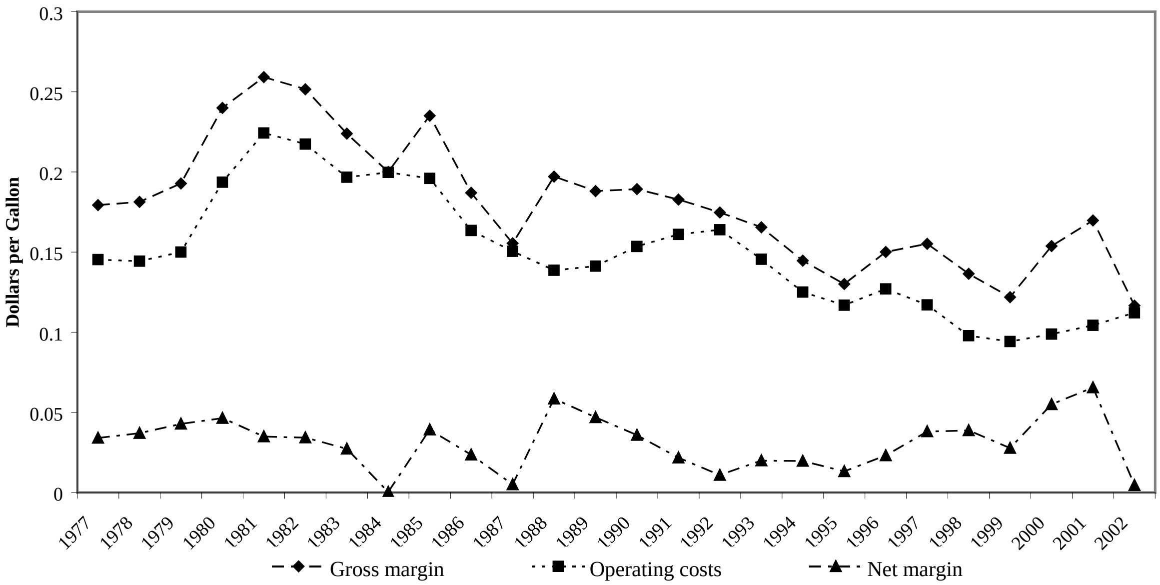
Source: Energy Information Administration, *Financial Reporting System Public Data* , Schedules 5120 and 5210. http://www.eia.doe.gov/emeu/finance/frsdata.html.

Figure 3-16
Return on Investment by Segment, Five-Year Averages



Source: Energy Information Administration, *Financial Reporting System Public Data* , Schedules 5120 and 5210. http://www.eia.doe.gov/emeu/finance/frsdata.html.

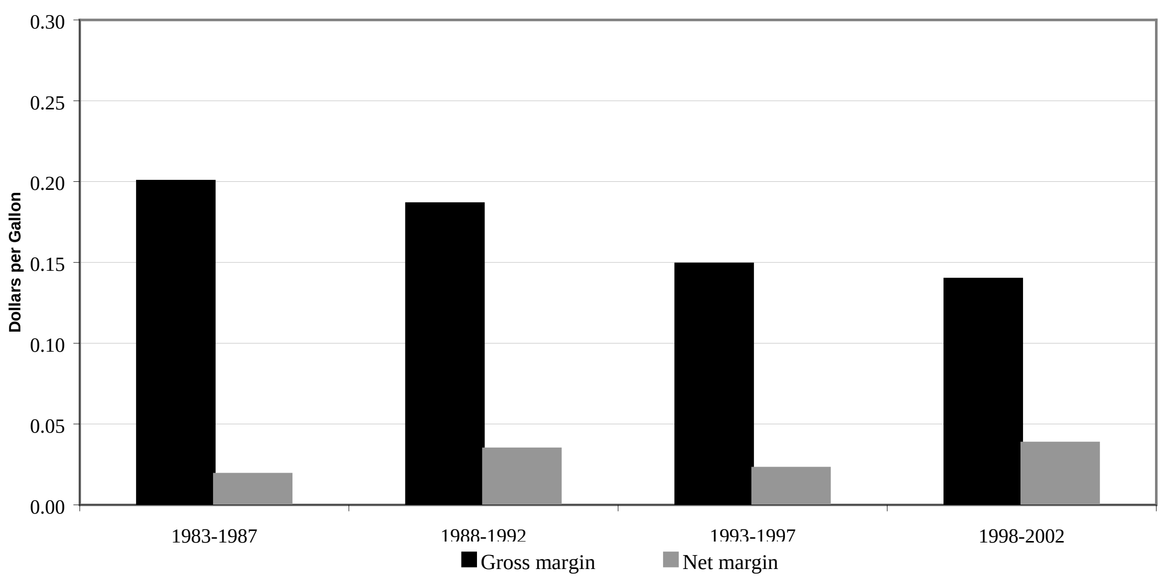
Figure 3-17
U.S. Refined Product Margin
2002 Real Dollars



Source: Energy Information Administration, *Financial Reporting System Public Data*, Schedules 5210, 5211, 5212.

Note: There are no taxes on spot sales, so the margin figures do not include taxes.

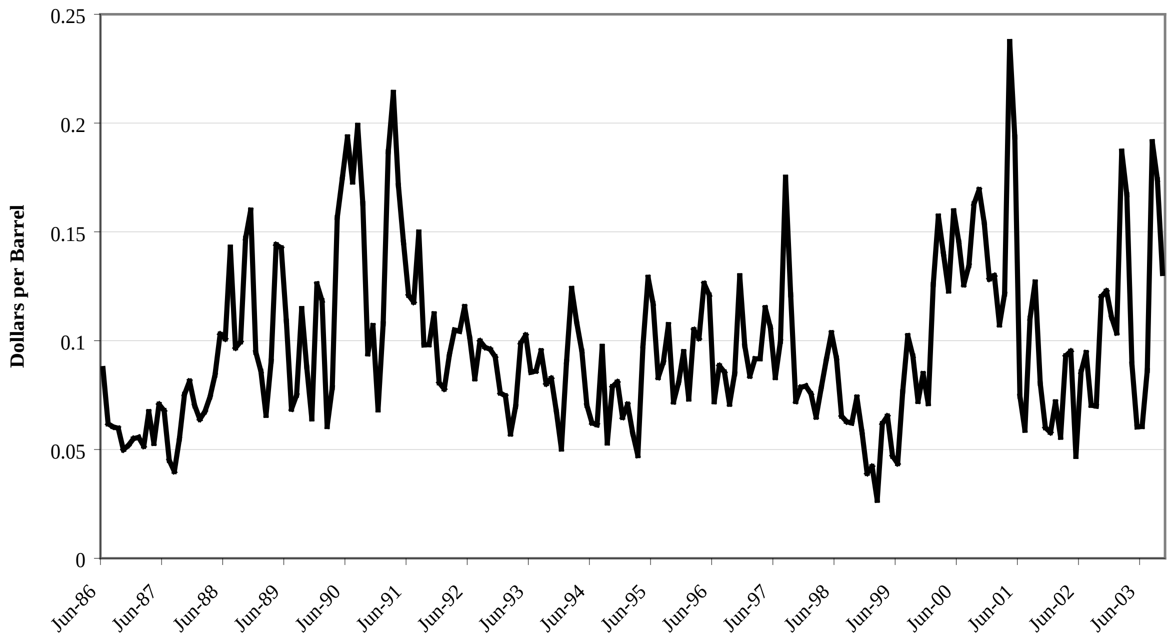
Figure 3-18
U.S. Refined Product Margin, Five-Year Averages
2002 Real Dollars



Source: Energy Information Administration, *Financial Reporting System Public Data*, Schedules 5210, 5211, 5212.

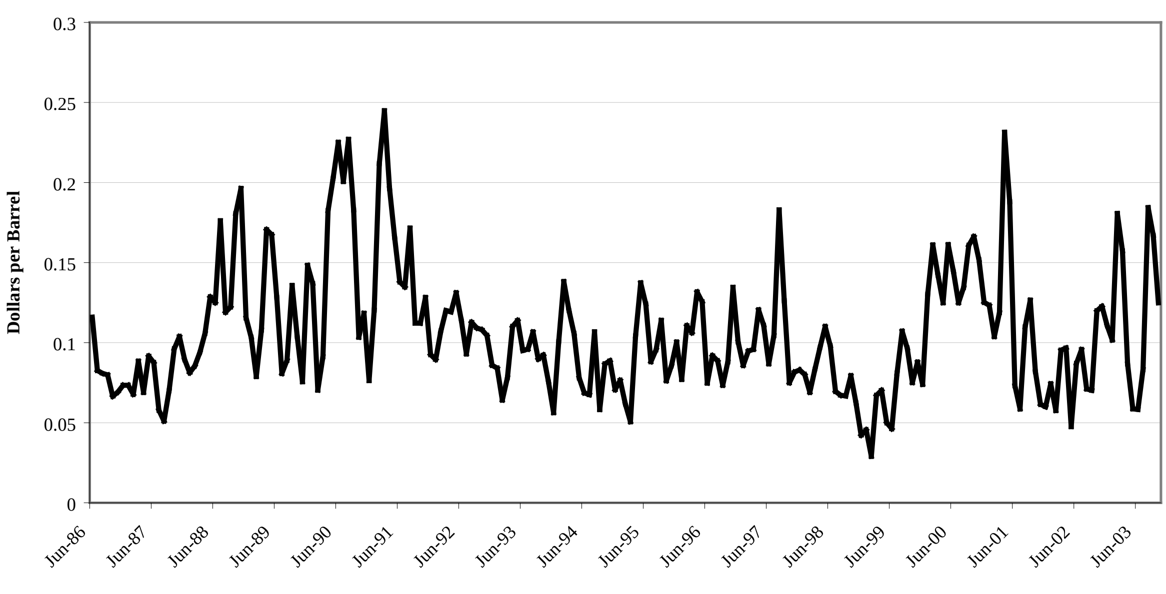
Note: There are no taxes on spot sales, so the margin figures do not include taxes.

Figure 3-19a
3-2-1 Crack Spread



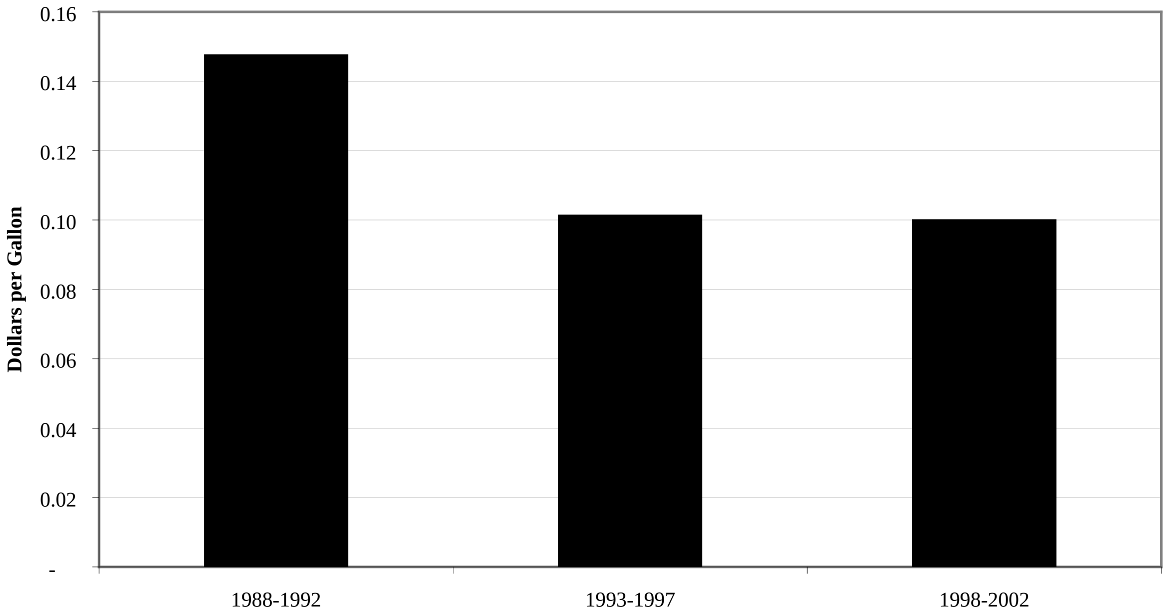
Source: Energy Information Administration, *Historical Petroleum Data* , http://tonto.eia.doe.gov/oog/ftparea/wogirs/xls/psw13vdall.xls.

Figure 3-19b
3-2-1 Crack Spread
2002 Real Dollars



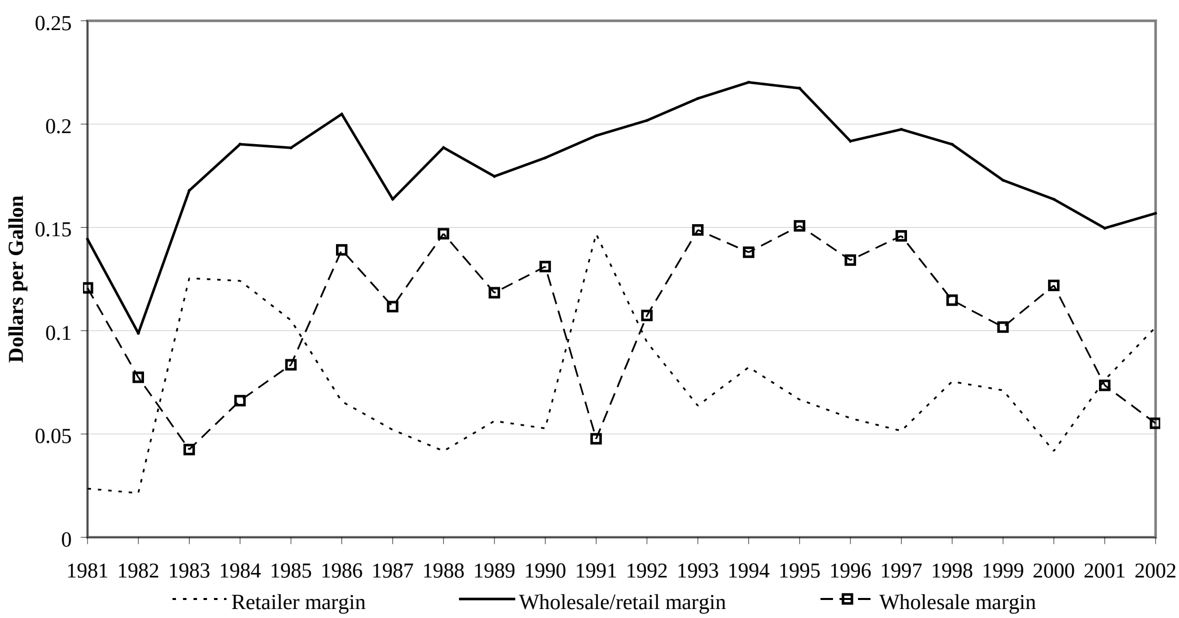
Source: Energy Information Administration, *Historical Petroleum Data* , http://tonto.eia.doe.gov/oog/ftparea/wogirs/xls/psw13vdall.xls.
Data wss deflated using a monthly Producer Price Index for all commodities (U.S. Department of Labor: Bureau of Labor Statistics).

Figure 3-20
3-2-1 Crack Spread, Five-Year Averages
(Real 2002 dollars)



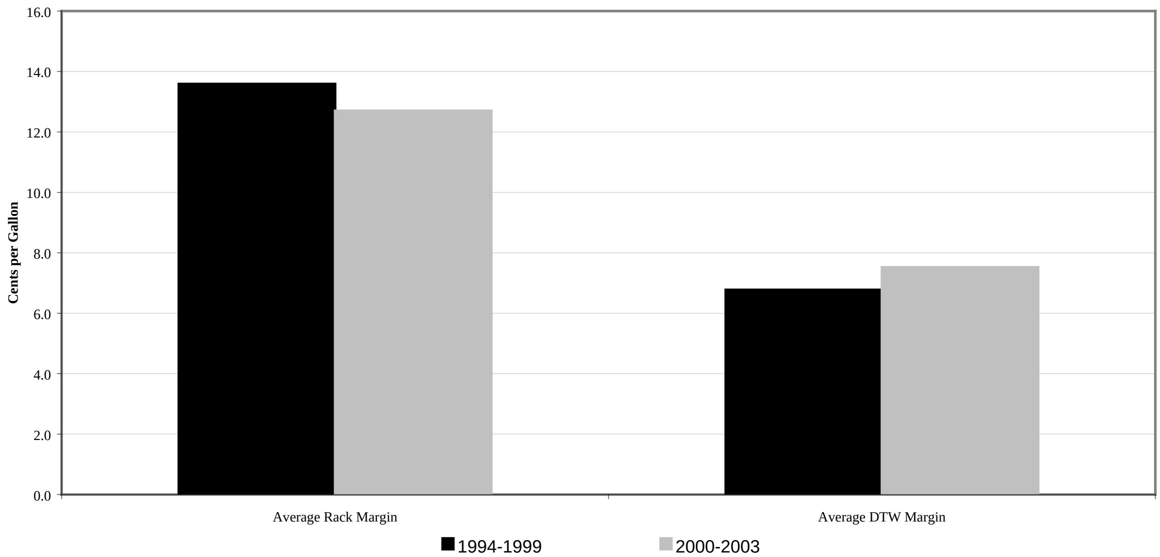
Source: Energy Information Administration, *Historical Petroleum Data* , http://tonto.eia.doe.gov/oog/ftparea/wogirs/xls/psw13vdall.xls.

Figure 3-21
Marketing Margins
2002 Real Dollars



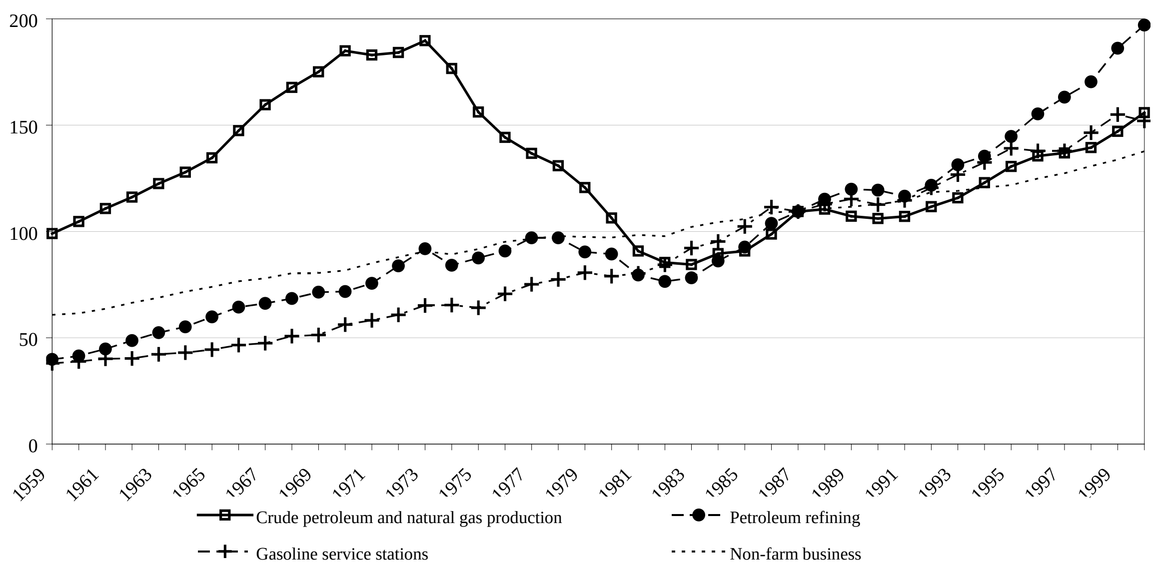
Sources: Energy Information Administration, *Financial Reporting System Public Data*, schedule 5212.

Figure 3-22
Average Marketing Component Margins
Multiyear Averages



Sources: Energy Information Administration, *Petroleum Marketing Monthly* , Table 32: Conventional Motor Gasoline Prices by Grade, Sales Type, PADD, and State, April 30, 2004.

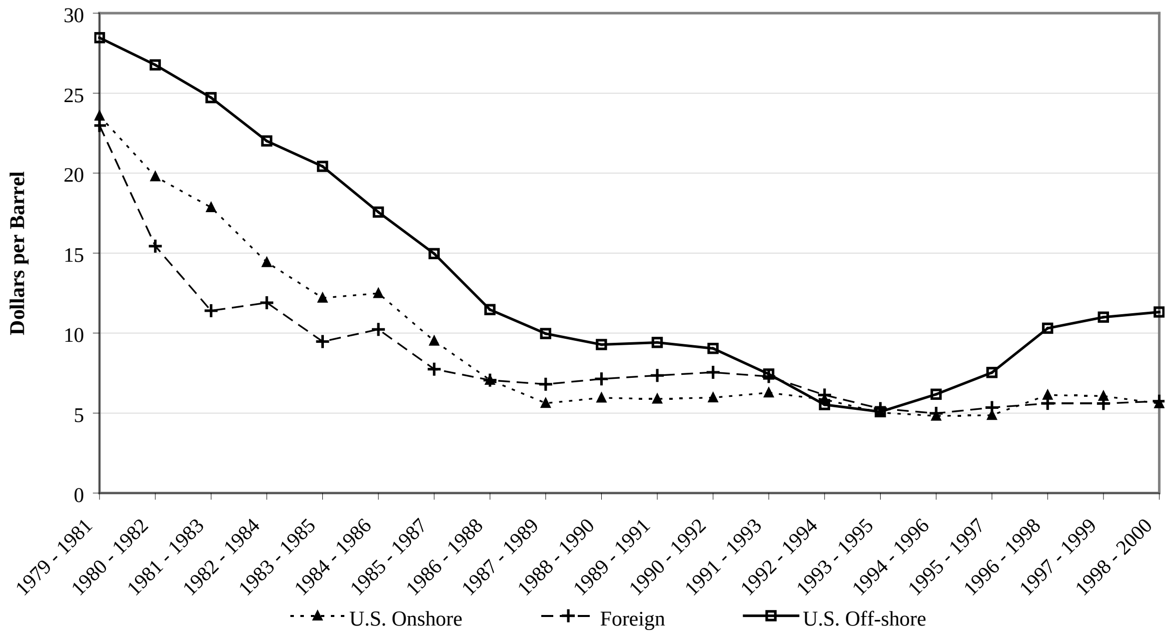
Figure 3-23
Labor Productivity



Sources: Bureau of Labor Statistics, *Data from Industry Productivity Database* , February 10, 2003; Bureau of Labor Statistics, *Industry Labor Productivity Tables* , August 25, 2003.

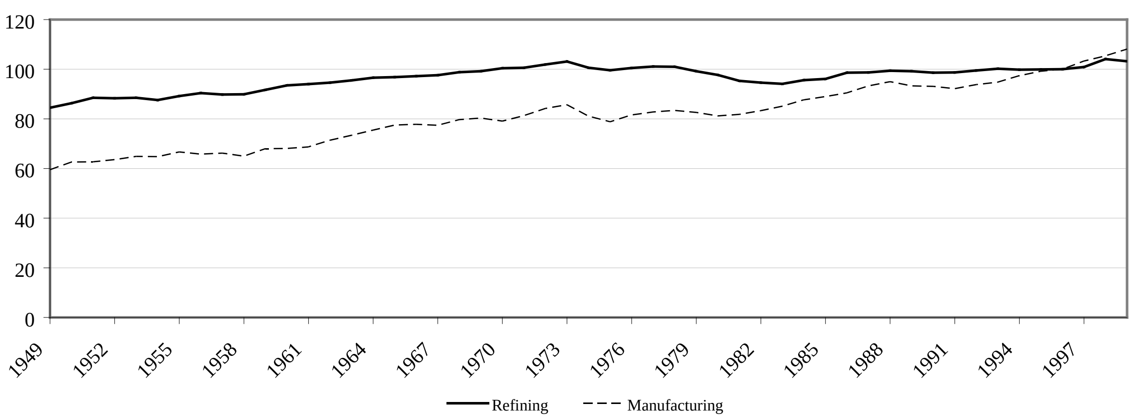
Note: The 3-digit industries codes are 131, 291 and 554. These labor productivity numbers were compared with Non-Farm Business Labor productivity, BLS series number PRS85006093.

Figure 3-24
Finding Costs for FRS Companies, 2002 Real Dollars



Source: Energy Information Administration, *Major Energy Producers 2001* , Figure 26.

Figure 3-25
Multifactor Productivity



Bureau of Labor Statistics, *Major Sector Multifactor Productivity Index* , series MPU 312903 (Petroleum Refining) and MPU 300003 (Manufacturing).

Chapter 4

Mergers and the Petroleum Industry Since 1985: The Empirical Data

The 1982 Merger Report examined mergers by leading petroleum companies ("LPCs") that occurred from 1971 to 1981. The 1989 Merger Report extended this examination to LPC mergers from 1982 to 1984.[1] Following essentially the same methodology as the previous reports, this chapter analyzes merger activity by LPCs from 1985 to 2001. This review concludes that since 1985 there have been three distinct periods of LPC merger activity. In the first period, between 1985 to 1990, LPCs acquired somewhat more assets than they divested. The second period, 1991 through around 1996, saw less overall merger activity, with LPCs divesting more assets than they acquired by a substantial margin. The final period, 1997 to 2001, displayed an extraordinary burst of merger activity, including a number of very large whole-company consolidations among the LPCs.

Section I identifies the LPCs included in our analysis, and describes trends in merger activity for LPCs. Section II examines whether the sharp increase in LPC merger activity after 1996 reflected the overall growth of the economy or simply the growth of the oil industry, and Section III compares measures of LPC merger activity with measures of merger activity across other industries. Section IV concludes with a discussion of the efficiencies that merging firms have claimed in a number of the larger transactions. This section relies only on publicly available data. Appendix A describes the methodology used to define LPCs and transactions, and describes the LPCs included in the analysis.

I. Trends in Merger Activity from 1985 to 2001

This section reports the numbers and values of acquisitions and divestitures by LPCs in each year between 1985 and 2001, distinguishing between "whole-company transactions" and "all transactions." Tables 4-1 through 4-4 identify the LPCs in the four sample periods.

A. Transactions Valued at Greater than $10 Million in Current Dollars

Table 4-5 shows "whole-company" acquisitions and divestitures

[1] The previous Merger Reports explored whether merger activity by LPCs had been increasing and whether LPCs were more likely to undertake acquisitions than were large corporations in other industries. Both Merger Reports found that the apparent increase in LPC merger activity could be attributed to the relative size of the LPCs: that is, acquisitions by petroleum companies were no more numerous than acquisitions by firms of comparable size in other industries. Both Merger Reports also found that LPCs concentrated their acquisitions on energy-related assets while divesting non-energy-related assets.

by the LPCs between 1985-2001.[2] Whole-company acquisitions combine into one firm the operations of two previously independent firms.[3] Whole-company divestitures are transactions in which an LPC is acquired by another firm.[4] The net value of acquisitions, *i.e.*, the value of acquisitions less the value of divestitures, is shown in the last column, labeled "Net." Besides showing the data for each year, Table 4-5 also shows results aggregated over the four sample periods and for 1985-1997, 1998-2001, and the full period 1985-2001.

Between 1985 and 2001 there were 56 whole-company acquisitions, having an average value per transaction of $6.61 billion and a total transaction value of $370.4 billion. There were eight whole-company divestitures over the whole period, for which the average transaction size was $37.0 billion and the total value of all transactions was $295.7 billion. Much of the whole-company acquisition activity, as measured by total dollar value of assets transferred, involved one LPC buying another. Accordingly, the net value of whole-company acquisitions by LPCs as a group was substantially less than the corresponding gross value. For example, the net value of acquisitions in 2001 was $3.21 billion, compared with a gross value of acquisitions of $71.7 billion.

Of the 56 whole-company transactions from 1985 through 2001, 30 occurred in the last four years. The very high incidence of whole-company transactions in recent years is even more striking when measured by the value of assets transferred. During 1985-1997, $32.0 billion in assets changed hands as a result of 26 whole-company acquisitions. This figure was greater by more than a factor of 10 for 1998-2001, amounting to $338.4 billion in transferred assets. The nature of the transactions was also different. In earlier periods, most of the transaction value was accounted for by LPCs buying non-LPCs, while in the last four years the majority of the transaction values were accounted for by LPCs buying each other.

Table 4-6 presents the data on *all* LPC acquisitions and divestitures, including both whole-company and part-company transactions. The number of all acquisitions between 1985 and 2001 is almost eight times greater than the number of whole-company acquisitions alone (445 v. 56). The average value for all transactions is substantially smaller: $1.12 billion for all transactions versus $6.61 billion for whole company transactions. Nonetheless, non-whole-company transactions can be very large, such as Phillips Petroleum's $7.5 billion acquisition of ARCO's Alaskan operations in 2000. A comparison of Table 4-6 with Table 4-5 shows that

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[2] A "whole-company" acquisition is one in which all, or substantially all (at least 90%), of the ownership interest in an independent business organization is transferred to another firm. In a few instances, when the acquired entity had owners that held a substantial portion of the company's ownership interest or were affiliated with companies that had convoluted capital structures, the application of the definition became somewhat problematical. These cases were generally counted among all transactions, not among whole-company transactions.

[3] The column labeled "Count" shows the total number of transactions in each period in which another firm was acquired by an LPC; the next two columns show the average and total value of transactions in millions of current dollars.

[4] The number of "whole-company" divestitures is shown, followed by the average and total value of the divestitures in current dollars.

26% of the value of acquisition activity between 1985 and 2001 was in part-company transactions and that 39% of all divestiture activity was in part-company transactions. Table 4-6 also shows a much higher level of all divestiture activity than whole-company divestiture activity for LPCs. More divestitures than acquisitions occurred over the entire period. In the periods 1990-1994 and 1995-1999, net acquisitions were negative because the LPCs sold more assets than they acquired.

B. Transactions Valued at Greater than $10 Million in 1971 Dollars

The 1982 Merger Report used a transaction threshold of $10 million in current dollars in measuring LPC transaction activity from 1971 onward. A constant threshold in current dollars neglects the effects of inflation on reporting transactions. From 1971 to 2001, the GNP deflator has increased from 100 to about 363: a $10 million transaction in 1971 dollars, all other things equal, would be valued at $36.3 million in 2001. Inflation tends to bias upward the number of included transactions relative to a constant, current dollar threshold. On the other hand, less public information on smaller transactions over time may have reduced the number of transactions that can be identified.[5]

To account for the effect of inflation, Tables 4-7 and 4-8 respectively report on whole-company and all transactions that exceeded $10 million in *1971 dollars*. This inflation-adjusted minimum threshold corresponds to current-dollar-value thresholds of $24.1 million in 1985 and $36.3 million in 2001. This adjustment changes both the criterion for including a transaction in any year and the value of included transactions. Adjusting the threshold causes only a small change in the number of whole-company transactions

[5] Factors other than inflation may bias measuring merger activity over time. First, as companies have become larger, the minimum size of transactions that firms consider to be "material" for purposes of making public accounting disclosures may have risen, especially if "material" refers to a percentage of the firm's total asset value. For example, one LPC made several multi-billion-dollar transactions for which it did not report the transaction values because, relative to its overall assets, the firm considered these transactions as "not material." (The values of these transactions, however, were available from other reliable sources.) Second, energy firms' capital structures have become more complicated over the years. The widespread use of limited partnerships and partial spin-offs of firms' assets into publicly-traded affiliates may make it more difficult to find information about transactions. These arrangements sometimes allow firms to screen many details of these units' operations under the umbrella of equity method accounting, in which reporting obligations are limited to the net income from partially owned entities; in other cases firms may report the acquisitions and divestitures only in the affiliates' financial reports. In some instances, these units have been the vehicles for many of the firms' acquisition activities. To the extent that (1) identification and tracking of affiliates' merger activities are more difficult (or not possible) and (2) more transactions have been occurring through equity affiliates, a downward bias in the reported number of transactions would result over time. The apparent increased complexity of LPC financial structures has not been systematically measured, but two illustrations are suggestive of the trend. In 1987, ARCO issued SEC filings only for the corporation itself and had a relatively straightforward corporate structure. Ten years later, tracking ARCO's merger activity required review of the filings of four affiliated entities: Atlantic Richfield Corp., ARCO Chemical, Vastar, Inc., and Lyondell Chemical. More generally, for the 14 U.S.-based LPCs in both the 1985-1989 and the 1995-1999 samples, their 1987 SEC 10-K filings used the terms "limited partnership" 14 times and "equity method" 67 times. The same firms' 1997 10-K filings used the terms "limited partnership" 26 times and "equity method" 113 times. These counts do not include the filings made by the equity affiliates of these LPCs.

between 1985 and 2001, from a total of 56 when the threshold is measured in current dollars to 49 when the threshold is measured in 1971 dollars. Adjusting for inflation decreases the average transaction value of whole-company acquisitions from $6.61 billion in current dollars to $2.13 billion in 1971 dollars; the total value of all whole-company acquisitions decreases from $370.4 billion in current dollars to $104.3 billion in 1971 dollars. The number of whole-company divestitures does not change because of the large size of these transactions, although adjusting for inflation causes the average value of divestitures to fall.

As Table 4-8 shows, adjusting for inflation for all transactions yields more pronounced effects, consistent with the typically smaller size of the part-company acquisitions and divestitures that comprise most transactions. Between 1985 and 2001, 445 acquisitions and 610 divestitures met the current $10 million threshold, whereas in 1971 dollars only 331 acquisitions and 491 divestitures did so. Similarly, 27% fewer acquisitions meet the higher 1971-dollar minimum threshold for 1985-1997, and 22% fewer acquisitions meet the higher level for 1998-2001. These data are consistent with a real change in the average reported transaction size. For 1985-1997, the average value of acquisitions was $158.5 million, but for 1998-2001 the average value was $978.1 million, both in 1971 dollars. The inflation-adjusted, average value of divestitures also sharply increased, rising from $105.3 million for 1985-1997 to $742.1 million for 1998-2001, both in 1971 dollars. The big increases in transaction activity and transaction values for the 1998 -2001 period were clearly real phenomena and not simply due to inflation.

C. Transactions Greater than $100 Million in 1971 Dollars

As a further check on inflation, data are presented on transactions exceeding $100 million in 1971 dollars, which is equivalent to a current-dollar threshold of $241 million in 1985 and $363 million in 2001. Examining only large transactions also acts as a check on possible reporting biases because information on large transactions is more likely than information on small transactions to be consistently disclosed in corporate financial filings or in reliable press reports.

Table 4-9 reports that 30 whole-company acquisitions meet the $100 million threshold in 1971 dollars. The total value of whole-company transactions is only slightly lower using the $100 million threshold than using the $10 million threshold: $103.6 billion compared to $104.3 billion, all in 1971 dollars. The number of whole-company divestitures is the same under the $10 million and $100 million thresholds in 1971 dollars because these transactions were large.

As Table 4-10 shows for all transactions, 125 acquisitions between 1985 and 2001 exceeded $100 million in 1971 dollars. Overall, the acquisitions exceeding $100 million accounted for 38% of the number of all acquisitions exceeding $10 million and 95% of the value of all such acquisitions, all in 1971 dollars. Many divestitures that meet the $10 million threshold do not meet the $100 million threshold, both in 1971 dollars. The number of divestitures falls from 491 exceeding $10 million to 122 exceeding $100 million, and the total value of divestitures falls from $139.6 billion to $125.8 billion, all in 1971 dollars. Table 4-10 also shows that, with a $100 million 1971 dollar threshold, the net value of transactions (the value of acquisitions less the value of divestitures) is $9.56 billion for the entire period, $2.93 billion for 1985-1997, and $6.62 billion for 1998-2001. This contrasts with $3.03 billion for 1985-2001, -$2.15 billion for 1985-1997, and $5.18 billion for 1998-2001, under the $10 million 1971 dollar minimum. The net value of LPC transactions under the higher threshold is larger because the share of all divestitures that were valued between $10 million and $100 million in 1971 dollars is significantly greater than the share of all acquisitions within this size range.

Table 4-11 lists and provides some detail on all transactions (both acquisitions and divestitures) occurring between 1985 and 2001 which exceeded $1 billion in 1971 dollars. There were 24 such transactions. Ten involved LPCs based outside the U.S. Two (Amoco/Dome and Conoco/Gulf Canada) involved a domestic LPC purchasing assets located primarily outside the U.S. Two involved joint ventures outside crude oil and refined petroleum products, while two others were conglomerate spin-offs in public stock offerings. Of these large transactions 58% were whole-company deals, compared with 6% in the sample as a whole. A substantially greater proportion of these transactions was between LPCs: 54% for the billion-dollar transactions, compared to 12% in the overall sample.

In sum, LPC merger activity in inflation-adjusted dollars has fluctuated greatly between 1985 and 2001. During the last four years of the survey, however, the number and size of mergers were substantially higher than during the preceding years. Total (gross) acquisitions by LPC in each of those four years from 1998 to 2001 exceeded $20 billion in 1971 dollars, far outpacing yearly totals for earlier years back to 1985; net acquisitions were at much lower levels, mostly because several of the largest transactions involved whole-company consolidations among the LPCs themselves.

The high level of LPC merger activity in recent years was also significantly greater in real terms than that of the earlier merger wave of the late 1970s and early 1980s. For example, the peak in this earlier merger wave, 1984, was a year with a number of major consolidations, including the Texaco/Getty and Chevron/Gulf mergers. The 1989 Merger Report estimated the (gross) value of LPC acquisitions in 1984 at $14.9 billion in inflation-adjusted dollars; gross acquisition values for 1979 through 1981, the other relatively active years during this earlier merger wave, ranged between $2.2 billion and $4.1 billion in inflation-adjusted dollars.[6]

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[6] 1989 Merger Report, Table 5. The figure for 1984 value of acquisitions reported in the text above reflects an adjustment for changes in group size; unadjusted for group size, the real value of transactions reported in the 1989 Merger Report was $13.1 billion. Slight differences in the 1989 Merger Report's and the present report's indices for adjusting for inflation, together with possible systematic differences in identifying relevant transactions, caution against making a strict comparison of the merger data series in the two reports. However, these factors are not significant enough to affect the

II. Relationship Between LPC Merger Activity and LPC Group Size

The level of merger activity may be related to industry size as measured by dollar revenues or value of assets. This section examines on an aggregated level whether LPC merger activity is related to LPC group or industry size. Table 4-12 presents total annual revenues and year-end assets of the LPCs for 1984-2001, in both current dollars and 1971 dollars.[7] In current dollars, total revenue grew from $538 billion in 1985 to $833.3 billion in 2001, with periods of substantial fluctuation that correspond to changes in crude oil and refined products prices. Assets, measured in current dollars, grew from $435.9 billion in 1984 to $689.1 billion in 2001, with less dramatic year-to-year variations. In constant 1971 dollars, both total revenues and total assets for all LPCs remained approximately constant: 1984 revenue was $229.8 billion and 2001 revenue was $232.4 billion; 1984 assets were $186.2 billion and 2001 assets were $192.2 billion. As the data on net acquisitions suggest, acquisition and divestiture activity of the LPCs has resulted in little, if any, net growth in the size of the group. Because the economy has grown substantially since 1984, these data imply that the LPCs as a group have declined in relative importance in the economy. For example, LPCs accounted for 30.6% of the revenue and 30.9% of the assets of the *Fortune 500* in 1984, but by 2001 they accounted for only 11.2% of the sales and 3.6% of the assets.[8] Consequently, the observed surge in LPC merger activity in recent years cannot be attributed to their growth as a group.

Even though the real revenue and asset values of the LPCs as a group have remained relatively constant, fluctuations in their merger activity could be driven by other factors related to LPC financial conditions. For example, in times of high oil prices, LPCs with crude holdings have increased revenue, net cash flows and asset values. In times of low oil prices, LPCs with relatively strong financial positions may find opportunities for acquisitions at "bargain" prices.

Table 4-13, which examines these hypotheses, presents the annual value of acquisitions, divestitures, and net acquisitions by the LPCs relative to their sales and book asset values the previous year.[9] If the cash or asset positions of the firms are important in driving LPC mergers, a strong correlation might be observed between

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conclusion that recent LPC merger activity in real terms widely exceeded the levels seen in the late 1970s and early 1980s.

[7] Sales (or revenue) and assets were taken as reported by the parent LPCs. Unlike with regard to the compilation of merger transactions, no attempt to incorporate revenues and assets of unconsolidated subsidiaries and equity interests of the LPCs beyond what the LPCs elected to do in their application of usual accounting standards was made.

[8] Fortune 500 for 1984, FORTUNE (Apr. 29, 1985); Fortune 500: Largest U.S. Corporations, FORTUNE (Apr. 15, 2002).

[9] The prior year's revenue and asset values were used because the measured transactions affected the values for the current year. For example, if in 2000 company A bought company B, which was equally-sized, it would be appropriate to reflect that acquisition by showing a value of 100% as the ratio of the acquisition to A's sales. However, using A's sales in 2000 would include B's sales as well, and the figure calculated would be only 50% = (B's value)/(A's original value + B's value). The correct calculation requires using A's 1999 figures, to show the size of the transaction relative to A's original value: (B's value)/(A's original value) = 100%.

LPC revenues or assets and the value of acquisitions and divestitures, with merger activity in relatively constant proportion to sales or assets. This is not the case. Acquisition values, for example, equaled only 0.2 % of all LPC revenue in 1994, but reached 18.2% of revenue in 1999 and 2000. Similarly, divestitures as a percentage of revenue show a considerable variation.

III. Comparison of LPC and Merger Activity Generally

How have trends in LPC merger activity levels compared with merger trends in the general economy? Table 4-14 presents yearly data from *Mergerstat* on aggregate dollar values of transactions involving at least one U.S. company for 1985 to 2002 for which transaction prices were announced.[10] In Table 4-14, "Oil & Gas Mergers" refers to transactions where the seller is in the oil and gas industry, while "Total Mergers" refers to all merger transactions involving a U.S. company.

Yearly transaction activity for all industries remained fairly stable until 1996, when the number increased by 67% and the total dollar value increased by 39% compared to 1995. The number of mergers announced also increased dramatically in 1997 and 1999. In 1998, the number of mergers announced was virtually unchanged from 1997, but the aggregate real value of the transactions increased by 81% from 1997. In 2000, while the number of mergers announced increased slightly, the dollar value fell by 7%. The end of the stock market boom and the recession caused a dramatic drop in economy-wide merger activity in 2001 and 2002, especially in transaction value.

Mergers in the oil and gas industry generally followed the same pattern. According to the *Mergerstat* data, 1998 stands out as a blockbuster year in terms of transaction value. Several mergers were announced or consummated among the largest oil companies: BP and Amoco merged, Exxon and Mobil announced their

[10] According to *Mergerstat*, it "tracks formal transfers of ownership of at least 10% of a company's common equity where the purchase price is at least $1 million (or £500k and equivalent values in other currencies) and where at least one of the parties (the buyer or seller parent company) is a U.S., Canadian, or European entity. Open market stock purchases, new equity investments, private placements, new joint ventures, asset swaps, and real property (land, pipelines, transmission towers, oil rigs, buildings, shopping centers, office buildings and cable systems) are not recorded. For sellers in the database with pending competing bids, only the highest offer is included in *Mergerstat* trend analysis statistics. Also, *Mergerstat* records transactions as they are announced, not as they are completed.

"Unless otherwise noted, all Merger & Acquisition statistics contained in *Mergerstat's* database reflect completed or pending transactions, as of the end of the applicable period. To determine whether the transactions meet the *Mergerstat* requirements, the research analysts conduct company interviews and consult company press releases, source documents, SEC filings, company Web site information, and other various sources of corporate financial disclosure." *Mergerstat Company Overview, available at* http://www.mergerstat.com/new/company.asp.

Mergerstat data differ from those presented earlier in this chapter in several respects. First, *Mergerstat* may classify the date of transaction as of the announcement date, whereas our earlier analysis classifies them as of the consummation date. This may change the year in which a transaction shows up in the database, particularly for large transactions that undergo extensive antitrust review. Second, *Mergerstat* reports on companies by SIC classification, whereas this report uses a sample of companies selected under a more specific set of criteria. Finally, *Mergerstat* may treat certain types of transactions, such as corporate reorganizations, differently than this report does.

planned merger, and Marathon and Ashland formed a joint venture combining downstream operations. The oil and gas industry accounted for only 0.8% of the total number of transactions in 1998 but 12.9% of the total transaction value.[11] Although the recent recession does not appear to have affected the number of mergers in the oil and gas industry as greatly as in other industries, its effects are clearly reflected in the much lower value of oil and gas industry transactions in 2002.

IV. Business Rationales and Efficiency Claims in Petroleum Mergers

Changes in demand, cost, and regulatory conditions can induce horizontal or vertical restructuring of an industry. Mergers, acquisitions, and joint ventures can play an important role in efficient industry restructuring, inasmuch as they affect firm scale, vertical integration, or the diffusion of technological advances. This section reviews the publicly available record on claimed efficiencies and business rationales for specific petroleum mergers.[12] Some important transactions reversed longstanding integration between upstream and downstream levels, suggesting that firms perceived a reduction in the benefits of integration compared to contractual alternatives. Other transactions have maintained integration between upstream and downstream levels, indicating different or more complex motivations for these transactions.[13]

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[11] The year 1985 was also a high point for *Mergerstat* asset sales by oil and gas firms. The oil and gas industry accounted for 2.9% of the total number of transactions and 12.9% of total transaction value. The volume of transactions shown by *Mergerstat* for 1985, unlike several other years, is significantly higher than that in our sample. The divestiture activity listed in Table 4-5 indicates that about 51.2% of the *Mergerstat* transactions may have been by LPCs and that about 46.3% of the *Mergerstat* transaction value might be attributed to LPC transactions. Many of the 1985 LPC divestitures are accounted for by Chevron's sale of various parts of Gulf to satisfy FTC antitrust concerns. A significant number of non-LPC transactions occurred in 1985, including Allied Chemical's purchase of Signal Oil and Occidental Petroleum's acquisition of the Midcon pipeline.

[12] The transactions are: the Shell/Texaco joint venture; BP's acquisitions of Amoco, ARCO, and Burmah Castrol; Exxon/Mobil; Chevron/Texaco; Phillips/Tosco; Conoco/Phillips; Tosco's refinery acquisitions in the mid-1990s and its acquisition of the refining and marketing assets of Unocal; the Marathon/Ashland joint venture and Marathon Ashland's acquisition of the Michigan assets of Ultramar Diamond Shamrock; Valero's acquisition of the remainder of Ultramar Diamond Shamrock and earlier refinery acquisitions; Sunoco's acquisition of several Philadelphia-area refineries from ARCO, Chevron and El Paso; and Kerr-McGee's acquisition of Oryx. Also examined were a series of crude oil mergers and acquisitions involving several major independent crude producers – Kerr-McGee, Devon Energy, and Pioneer Natural Resources.

Most of these transactions involved firms that had both upstream (exploration and production) and downstream (refining and marketing) businesses, or that had only downstream businesses. Several transactions involving firms primarily active in domestic crude oil production were also quite large, however, and the available information for these transactions was examined as well.

Few data exist to corroborate company claims or expectations of efficiencies. In antitrust analyses, company claims are not always substantiated, nor can the analyst always differentiate between merger-specific cost savings and those improvements that would have occurred in any event. Nevertheless, it is reasonable to use these estimates to understand the types of cost savings that the firms have identified as arising from consolidations (in light of publicly traded firms' legal obligations not to exaggerate efficiency claims).

[13] While mergers and acquisitions have tended to increase the size of the largest petroleum companies, a substantial number of divestitures accompanied this growth, as firms restructured their portfolios of assets. The FTC mandated some of these divestitures to resolve competitive concerns raised by mergers and acquisitions, but many divestitures were voluntary.

It is difficult to make strong generalizations about efficiencies and business rationales from recent industry mergers. The transactions involved different mixes of assets, and firm-specific factors are likely to have been important in determining efficiencies from consolidations. Moreover, public information on sources of efficiencies is often sketchy.

Table 4-15 summarizes our findings. The most commonly cited source of efficiencies involved general "operating synergies" or "organizational efficiencies." Statements made regarding the three BP acquisitions, Exxon's merger with Mobil, the Shell/Texaco joint ventures, the subsequent Chevron/Texaco combination, Phillips/Tosco, Conoco/Phillips, and the Marathon Ashland joint venture all mentioned some form of cost savings from reorganizing the combined business.[14] These savings claims appear to be related to administrative and corporate overhead functions. Most of the firms mentioned reductions in staff as an important factor in cost savings. The president of the Petroleum Industry Research Foundation, Larry Goldstein, noted that "[t]he hidden value in mergers

[14] Shell Oil Company, *Downstream Gas and Power Generation*, *available at* http://www.shellus.com/SAR00/oil.html; *Oil Megamergers are Producing Unexpected Results, Moody's Report Says*, PETROLEUM FINANCE WEEK (Nov. 20, 2000); BP p.l.c., *BP and AMOCO Merge to Enter Global Top Trio of Oil Majors* (Aug. 11, 1998) (press release), *available at* http://www.bp.com/genericarticle.do?categoryId=120&contentId=2006699; Peter Davies (V.P. and Chief Economist of BP), *The Changing World Petroleum Industry - Bigger Fish in a Larger Pond* (paper presented to the British Institute of Energy Economics Conference, St. John's College, Oxford, Sept. 21, 1999), *available at* http://ww.dundee.ac.uk/cepmlp/journal/html/article6-14.html.; BP p.l.c., *BP Amoco and ARCO in $26.8 Billion Deal Agreed by Boards of Both Companies* (Apr. 1, 1999) (press release), *available at* http://www.bp.com/genericarticle.do?categoryId=120&contentId=2001262; BP p.l.c., *Burmah Castrol Strategy Presentation* (Mar. 14, 2000), *available at* http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/B/Burmah_Castrol_BP_Strategy_Presentation.pdf; ExxonMobil Corporation, *ExxonMobil-The Premier Petroleum and Petrochemical Company* 36-37 (Investor/Media Presentation by L.R. Raymond, Chairman and CEO of ExxonMobil) (Aug. 1, 2000); ExxonMobil Corporation, *2001 Financial and Operating Review* 68, *available at* http://www2.exxonmobil.com/corporate/newsroom/publications/c_fo_01/pdfs/downstream_refine.pdf; ExxonMobil Corporation, *ExxonMobil Provides Merger Update; Benefits Greater Than Previously Forecast* (Dec. 15, 1999) (press release), *available at* http://www2.exxonmobil.com/Corporate/Newsroom/Newsreleases/corp_xom_nr_151299.asp; ChevronTexaco Corporation, *Chevron and Texaco Agree to $100 Billion Merger Creating Top-Tier Integrated Energy Company* (Oct. 16, 2000), *available at* http://www.chevrontexaco.com/news/archive/chevron_press/2000/2000-10-16.asp; ChevronTexaco Corp. *2001 Annual Report*; ChevronTexaco Corp., *Presentation by David O'Reilly, Chairman and Chief Executive Officer of Chevron Corp. and Peter Bijur, Chairman and Chief Executive Officer of Texaco, Inc.*, *available at* http://www.chevrontexaco.com/news/spotlight/docs/chevrontexaco.pdf; ChevronTexaco Corp., *Investment and Opportunity 2001: The View From Chevron*\fs24fs24 (speech by David J. O'Reilly, Chairman and CEO of ChevronTexaco Corp.) (Mar. 26, 2001), *available at* http://www.chevrontexaco.com/news/archive/chevron_speech/2001/2001-03-26.asp; Phillips Petroleum Co., *2001 Annual Report*; Conoco Inc., *2001 Annual Report*; ConocoPhillips Company, *ConocoPhillips to Improve Return on Capital Employed* (Nov. 22, 2002) (press release), *available at* http://www.conocophillips.com/news/nr/112202_analyst.asp; ConocoPhillips Company, *Conoco Chairman–Proposed Merger of Equals with Phillips an "Excellent Strategic Fit"* (Apr. 23, 2002) (press release), *available at* http://www.conocophillips.com/news/nr/rel_con_02_38.asp; Mike Sobczyk, *Marathon, Ashland Joining Forces*, THE COURIER.COM (May 16, 1997), *available at* http://www.thecourier.com; Marathon Ashland Petroleum, *About Us-Refineries*, *available at* http://www/mapplc.com/about/refineries.html.

is that you cut people and inventory."[15] These merger-related cuts would be in addition to significant staffing reductions that had already been made prior to the mid-1990s: Weston *et al.* report that employment at eight major oil companies fell from 800,000 to 300,000 between 1980 and 1992.[16]

Another common source of claimed efficiencies was integration of refinery systems, pipeline systems, or other distribution systems. Documents, speeches and other statements regarding Exxon/Mobil, Phillips/Tosco, Marathon/Ashland, Valero/Ultramar Diamond Shamrock, Valero's other refinery acquisitions, and Sunoco's refinery acquisitions all mentioned such integration as an important source of efficiencies.[17] Specifically, these firms sometimes noted that a larger refinery system allowed for movements of feedstocks and blending stocks across refineries and therefore more efficient use of capacity at each refinery. Valero claimed that a larger, more extensive distribution system would allow the firm more timely access to markets when arbitrage opportunities arose.

The most common efficiency claim involved greater economies of scale.[18] At the upstream level, consolidations among the smaller, independent producers are consistent with gains to scale in exploration and production ("E&P"). Examples of such consolidations where size-related synergies appeared important include Kerr-McGee's acquisition of Oryx, Devon's acquisition of Santa Fe Snyder and other firms, and the merger of Mesa and Parker & Parsley, which created Pioneer Natural Resources.[19] In addition

[15] Neela Banerjee, An Oil Merger That Assumes That Bigger Is Not Just Better, It's Necessary, N.Y. TIMES , Oct. 16, 2000, at A-22.

[16] J. Fred Weston, Brian Johnson, and Juan A. Siu, *Mergers and Restructuring in the World Oil Industry* 13 (2004), *available at* http://www.anderson.ucla.edu/faculty/john.weston/papers/oilindustry.pdf. Generally, the authors conclude that gains from internal corporate restructuring (such as decentralization of organizational control, selling of unrelated businesses, and increased attention by firms to industry segments where they appeared to have superior performance) and investment in new technologies began to level off in the 1990s, and, under continuing downward price pressures particularly since 1995, petroleum firms increasingly considered mergers and acquisitions as a means of further increasing efficiencies. *Id.* at 12-16.

This suggested turn to increased mergers relative to internal restructuring, including the sale of unrelated businesses, is broadly consistent with the data presented in this chapter showing LPCs divesting more assets than they acquired by a substantial margin during the first half of the 1990s, with consolidations among the LPCs becoming more important afterwards.

[17] *See* Valero Energy Corp., *2000 Annual Report;* Valero Energy Corp., *2001 Annual Report*; Valero Energy Corp., *Mergers and Acquisitions, available at* http://www.valero.com; Valero Energy Corp., *Texas City Refinery*, *available at* http://www.valero/com/con1.php?p=16 ; Sunoco, Inc., *Sunoco's History*, *available at* http://www.sunoil.com/aboutsunoco/sunhistory.htm; Sunoco, Inc., *Sunoco Closes Eagle Point Refinery Acquisition; Provides Fourth Quarter Guidance* (Jan. 13, 2004) (press release), *available at* http://www.sunocoinc.com/aboutsunoco/newsandspeeches/3992.htm.
See also company documents cited in note 14, *supra*.

[18] Achieving additional scale economies was also seen by industry analysts as an important motivation for many recent mergers and joint ventures in the petroleum industry. *See, e.g.*, Oil and Gas Journal Research Center, *Profit Slump Strengthens Merger, Joint Venture Activity, available at* http://www.orc.pennnet.com/Articles/Article_Display.cfm?Section=Articles&ARTICLE_ID=114884.

[19] Kerr-McGee Corp., *1999 Annual Report* (Mar. 2000); Kerr-McGee Corp., *History*, *available at* http://www.kerr-mcgee.com/history.html. (Nov. 11, 2002); Kathy Shirley, *Strategic Visions, Merger Actions: Kerr-McGee Oil and Gas Defines Attributes*, EXPLORER (Nov. 2001); Devon Energy Corp., 2000 Annual Report (Mar. 2001); Devon Energy Corp., *Company History*, *available at* http://www.devonenergy.com/about_history.cfm; Richard McCaffery, *Devon Lands Santa Fe*, THE

to creating a critical mass said to permit the undertaking of larger scale projects, some of these mergers were associated with combining relatively nearby producing properties in "core" geographic areas with resulting operating cost savings and gains in regional E&P expertise.

Some observers have suggested somewhat different motivations for the "mega-mergers," such as Exxon/Mobil and BP/Amoco/ARCO. Verleger argues that exploration and production has become increasingly risky and that a larger firm is required to manage this risk efficiently.[20] Other industry analysts suggest that firms previously focused on exploration and production needed to become larger to manage more efficiently the larger risks that had arisen in the search for new oil fields in remote or politically inhospitable areas. One analyst believed that petroleum company "mega-mergers" are attractive because they "form companies with the power to undertake large capital and political risks in remote, high-cost environments" and have better negotiating strength vis-à-vis national companies.[21] Another analyst believed that deregulation, privatization and the opening of formerly closed markets were trends that had increased the size of the market, but that the resources required to compete in this more global market challenged even the largest petroleum firms.[22]

Downstream scale advantages at the plant level in refining and marketing probably also have provided impetus to some mergers. For example, as noted above, Sunoco acquired the ARCO and Chevron refineries to integrate them into Sun's existing refinery system. ExxonMobil integrated its refining system to purchase crude oil more efficiently, transfer feedstock and intermediate products among refineries, and transport refined products. Marathon and Ashland hoped to achieve similar efficiencies through their joint venture, and Valero had similar aims in integrating the refineries it acquired. Tesoro noted that the fluid catalytic cracking unit at its Anacortes, Washington, refinery can upgrade heavy vacuum gas oils from Tesoro's other refineries.[23] Other downstream cost savings may come through scale advantages in marketing. For example, BP plans to phase out the Amoco brand, suggesting economies in brand promotion.

MOTLEY FOOL (May 26, 2000); *Pioneer Natural Resources Co.*, OIL AND GAS INVESTOR (Oct. 1999); Pioneer Natural Resources Co., 2001 Annual Report; Pioneer Natural Resources Co., *Pioneer Seeks Limited Partners' Approval to Merge Parker & Parsely Limited Partnerships* (Oct. 19, 2001) (press release), *available at* http://www.pioneernrc.com/about_us/our_history.html http://www.pioneernrc.com/about_us/profile.html http://www.pioneerrc.com/news_room/index.html.

20 Subcommittee on Antitrust, Business Rights, and Competition of the Senate Judiciary Committee, *Hearings on Petroleum Industry Competition*, 105th Cong., 2d Sess., (Sept. 22, 1998) (prepared statement of Philip K. Verleger, Jr.). Verleger claims there are significant economies of scale in exploration and production, and that increased capitalization helps companies take very large exploration risks and better weather industry downturns. According to Verleger, the advantages of size are particularly apparent with respect to deep-water exploration.

21 Oil Megamergers Are Producing Unexpected Results, Moody's Report Says, PETROLEUM FINANCE WEEK (Nov. 20, 2000).

22 PennWell Corp., *Profit Slump Strengthens Merger, Joint Venture Activity*, OIL & GAS J. (1999), *available at* http://orc.pennnet.com/Articles/Article_Display.cfm?Section=Articles&ARTICLE_ID=114884.

23 Tesoro Petroleum Corp., *Anacortes, Washington* (2004), *available at* http://www.tesoropetroleum.com/anacortes.html.

One feature of public announcements of efficiency gains is that the amounts claimed often increased between the time the transaction was first announced and the time the deal was consummated. For example, Exxon estimated in December 1998 that its merger with Mobil would yield $2.8 billion in annual savings; by August 2000, this figure had increased to $4.6 billion. Similarly, the joint ventures between Shell and Texaco initially identified $800 million in annual savings by 1999; by November 2000, estimates of annual savings had increased to $3 billion. This increase in claims is perhaps not unusual because initial estimates are made when the acquiring firm has little knowledge of the details of the target firm's business, so any projected benefits from the deal are somewhat speculative. Firms may have an incentive to make conservative estimates of likely efficiencies because overestimates may lead to overpaying for the acquired firm.

Several transactions were notable in partially reversing the trend from earlier decades of vertical integration between upstream and downstream levels. Unocal exited the downstream market entirely, selling its refining and marketing business to Tosco in 1997. Sunoco and Ashland exited the upstream market, while BP, ExxonMobil, the Shell/Texaco joint venture, and Chevron all divested some refining assets. These transactions suggest that the benefits of vertical integration between upstream and downstream levels had fallen. A trend toward less vertical integration is also reflected in EIA's list of major energy companies which are obligated to report under EIA's Financial Reporting System ("FRS"). Between 1990 and 2000, the number of large, vertically integrated energy companies reporting to the EIA fell from 19 to 10, and the vertically integrated companies' share of FRS companies' total assets fell from 90% in 1990 to 59% in 2000.[24]

[24] EIA, *Performance Profiles of Major Energy Producers 2000*, 73-78. To be a FRS reporting company, a firm must be a U.S.-based corporation that has 1% or more of U.S. production or reserves of crude oil or natural gas *or* 1% or more of U.S. refining capacity or refined product sales volume. Six firms – Amoco, ARCO, Ashland, Coastal, Mobil, and Total (N. America) – left the FRS list as the result of consolidations, while the remaining three – Kerr-McGee, Sunoco, and Unocal – divested either upstream operations (Sunoco) or refining operations (Kerr-McGee and Unocal) and remain on the FRS list as non-integrated firms. Other firms not on the 1990 list were counted among the FRS companies in 2000, including non-integrated refiners such as Valero, Premcor and Tesoro.

Table 4-1 – Oil Merger Sample Companies' Basic Financial and Petroleum Information 1985-1989

Common or Trade Name	Parent(s)	1/1/1985 U.S. Refining Capacity (b/cd)	1984 U.S. Crude Oil Production (mmbbls)	1985 *Fortune* 500 Rank or Rank Equivalent [1]	1984 Sales ($ Mill.)	1984 Assets ($ Mill.)
Amerada Hess/ Hess	Amerada Hess Corp.	643,000[2]	26	41	8,277	6,353
Amoco	Amoco Corp.	986,000	149	10	26,949	25,734
ARCO	Atlantic Richfield Corp.	768,000	240	12	24,686	22,130
Ashland Oil	Ashland Oil, Inc.	353,343	1	42	8,253	4,037
BP / Sohio	British Petroleum Co. p.l.c.	456,000	232	5[3]	50,662	39,620
Chevron	Chevron Corp.	1,484,700	115	11	26,798	36,358
Citgo [4]	Southland Corp.	320,000	0	23[3]	12,035	3,340
Coastal	Coastal Corp.	171,300	3	55	6,225	3,296
Conoco Inc. [5]	E I du Pont de Nemours & Co.	429,774	44	7	35,915	24,098
Exxon	Exxon Corp.	1,200,000	285	1	90,854	63,278
Mobil	Mobil Corp.	750,000	113	3	56,047	41,851
Phillips Petroleum	Phillips Petroleum Co.	300,000	62	17	15,537	16,965
Shell Oil	Royal Dutch/ Shell Transport & Trading	1,005,000	195	2[3]	84,865	69,071
Texaco	Texaco, Inc.	1,199,000	210	5	47,334	37,744
Sunoco	Sun Co. Inc.	443,000[2]	71	20	14,466	12,789
Unocal	Unocal Corp.	490,000	59	27	10,838	10,203
Marathon Oil	United States Steel Corp.	588,000	60	15	18,274	18,989

Source: Rankings, Assets and Revenue: U.S. Industrial Corporations: *Fortune,* "The *Fortune* 500 Largest U.S. Corporations" (Apr. 29, 1985); Southland Corporation: *Fortune,* "The *Fortune* Service 500" (Jun. 10, 1985); Foreign Corporations: *Fortune*, "The International 500" (Aug. 19, 1985) ; Production: *Oil & Gas Journal*, "OGJ 400" (Sep. 9, 1985). Refining: Refining within the states: EIA, *Petroleum Supply Annual,* Table 33. "Refiners' Operable Atmospheric Crude Distillation Capacity as of January 1, 1985"; Refining within U.S. Territories: EIA, *Petroleum Supply Annual*, Table 32, "Capacity of Operable Petroleum Refineries by State as of January 1, 1985". Data from *Fortune* and *Oil & Gas Journal* used by permission.

Note:

[1] *Fortune* ranking based on prior year's sales.

[2] Amerada Hess and Sunoco both have refineries in U.S. territories, which are included in the table.

[3] *Fortune* includes only U.S.-based industrial companies in the *Fortune 500* ranking. Foreign and Service companies' ranks are projections based on where their revenues would have placed them in the *Fortune 500* had they been included in that list. Foreign companies were listed in the "The International 500". Their rankings are as follows: BP (2), and Royal Dutch/Shell (1). Southland Corporation, the only service company in the sample, was listed in "The *Fortune* Service 500," where it ranked 7th.

[4] The revenues and assets for Southland Corporation's "Gasoline retailing and supply" are $5,427 million and $1,246 million, respectively. Southland Corporation, *Form 10-K,* 326 (1985).

[5] The combined revenues and assets for du Pont's "Petroleum Exploration and Production" and "Petroleum Refining, Marketing and Transportation" are $22,300 million and $9,452 million, respectively. E I du Pont de Nemours, *Form 10-K*, 37-38 (1984).

Table 4-2 – Oil Merger Sample Companies' Basic Financial and Petroleum Information 1990-1994

Common or Trade Name	Parent(s)	1/1/1990 U.S. Refining Capacity (b/cd)	1989 U.S. Crude Oil Production (mmbbls)	1990 *Fortune* 500 Rank or Rank Equivalent [1]	1989 Sales ($ Mill.)	1989 Assets ($ Mill.)
Amerada Hess/Hess	Amerada Hess Corp.	575,000	26	89	5,589	6,867
Amoco	Amoco Corp.	984,000	142	12	24,214	30,430
ARCO	Atlantic Richfield Corp.	704,000[2]	241	22	15,905	22,261
Ashland Oil	Ashland Oil Inc.	346,500	1	58	8,017	4,456
BP	British Petroleum Co. p.l.c..	756,640	286	7[3]	49,484	51,042
Chevron	Chevron Corp.	1,621,000	176	11	29,443	33,884
Citgo and	Petroleos de Venezuela SA	344,500[5]	0	27[3]	13,677	8,907
	Southland Corp	141,000[6]	0	56[3]	8,421	3,439
Coastal	Coastal Corp.	275,300	3	54	8,686	8,773
Conoco [7]	E I du Pont de Nemours & Co.	406,500	41	9	35,209	34,715
Exxon	Exxon Corp.	1,147,000	253	3	86,656	83,219
Mobil	Mobil Corp.	838,000	107	6	50,976	39,080
Phillips Petroleum	Phillips Petroleum Co.	305,000	48	30	12,492	11,526
Shell Oil	Royal Dutch/Shell	1,078,600	180	4[3]	85,528	91,011
Sunoco	Sun Co. Inc.	595,000	0	46	9,927	8,699
Texaco	Texaco, Inc.	607,500[8]	175	10	32,416	25,636
Unocal	Unocal Corp.	295,600[9]	63	40	10,417	9,257
Marathon	USX Corp.	603,000	52	19	17,755	17,500

Source: Rankings, Assets and Revenue: U.S. Industrial Corporations: *Fortune,* "The *Fortune* 500 Largest U.S. Corporations" (Apr. 23, 1990); Southland Corporation: *Fortune*, "The Service 500" (Jun. 4, 1990); Foreign Corporations: *Fortune,* "The Global 500 List" (Jul. 30, 1990); Production: *Oil & Gas Journal*, "OGJ 300" (Oct. 10, 1990). Refining: Refining within the states: EIA, *Petroleum Supply Annual*, Table 39, "Refiners' Operable Atmospheric Crude Distillation Capacity as of January 1, 1990"; Refining within U.S. Territories: EIA, *Petroleum Supply Annual*, Table 38, "Capacity of Operable Petroleum Refineries by State as of January 1, 1990". Data from *Fortune* and *Oil & Gas Journal* used by permission.

Note:

[1] *Fortune* ranking based on prior year's sales.

[2] Capacity represents ARCO's direct capacity (414,000) plus its controlling interest (50%) in Lyondell Petrochemical (290,000). ARCO was attributed the entirety of Lyondell's capacity consistent with the 1982 Merger Report.

[3] *Fortune* includes only U.S.-based industrial companies in its *Fortune 500* ranking. Foreign and Service companies' ranks are projections based on where their revenues would have placed them in the *Fortune 500* had they been included in that list. Foreign companies were listed in the "The Global 500 List". Their rankings are: BP (10), PDVSA (76), and Royal Dutch/Shell (4). Southland Corporation, the only service company in the sample, was listed in "The Service 500", where it ranked 13th.

[4] The revenues and assets for Citgo, according to Southland's 1989 10-K, is $4,979 million and $1,060 million, respectively. Southland Corporation *Form 10-K*, 133-35 (1989).

[5] Capacity represents PDVSA various interests. PDVSA directly owns Champlin Refining & Chemical Inc. (130,000). PDVSA has 50% interest in Citgo (282,000) and is engaged in a 50/50 joint venture with Unocal, Uno-Ven Company (147,000), half of each's capacity is attributed to PDVSA.

[6] Capacity represents Southland Corporation's 50% interest in Citgo (282,000). Southland sold its interest in Citgo on January 31, 1990, and ceased to be an Oil Merger Sample firm.

[7] The revenues and assets for du Pont's "Petroleum" segment are $12,682 million and $10,392 million, respectively. E I du Pont de Nemours *Form 10-K*, 38 (1989).

[8] Capacity represents Texaco's direct refinery holdings (300,000) plus its interest in Star Enterprise. Star Enterprise (615,000) is 50/50 joint venture with the Saudi Aramco; Texaco is attributed with its 50% interest.

[9] Capacity represents Unocal's direct refinery holdings (222,100) plus its interest in Uno-Ven. Uno-Ven (147,000) is a 50/50 joint venture between Unocal and PDVSA; each is attributed half of the capacity.

Table 4-3 – Oil Merger Sample Companies' Basic Financial and Petroleum Information 1995-1999

Common or Trade Name	Parent(s)	1/1/1995 U.S. Refining Capacity (b/cd)	1994 U.S. Crude Oil Production (mmbbls)	1995 *Fortune* 500 Rank or Rank Equivalent [1]	1994 Sales ($ Mill.)	1994 Assets ($ Mill.)
Amerada Hess	Amerada Hess Corp.	505,000	25	172	6,699	8,338
Amoco	Amoco Corp.	998,000	93	21	26,953	29,316
Ashland Oil	Ashland Inc.	346,500	0	115	9,505	5,815
ARCO	Atlantic Richfield Corp.	683,550[2]	216	53	15,682	24,563
BP	British Petroleum Co. P.L.C.	700,500	221	12[3]	50,737	48,699
Chevron	Chevron Corp.	1,206,000	134	18	31,064	34,407
Citgo and affiliates	Petroleos de Venezuela SA	610,950[4]	0	29[3]	22,157	36,078
Coastal	Coastal Corp.	236,500	4	110	10,013	10,535
Conoco [5]	E I du Pont de Nemours & Co. Conoco Inc. [5]	438,000	33	14	34,968	36,892
Exxon	Exxon Corp.	992,000	206	3	101,459	87,862
FINA	Petrofina S.A.	230,000	5	92[3]	11,399	10,868
Mobil	Mobil Corp.	929,000	110	8	59,621	41,542
Phillips Petroleum	Phillips Petroleum Co.	320,000	45	79	12,367	11,436
Shell Oil	Royal Dutch/Shell	868,950[6]	151	4[3]	94,881	108,300
Sunoco	Sun Co., Inc.	785,000	0	151	7,792	6,465
Texaco	Texaco Inc.	650,600[7]	148	16	33,768	25,505
Unocal	Unocal Corp.	294,200[8]	50	163	7,072	9,337
Marathon Group	USX Corp.	570,000	40	45	16,799	17,517

Source: Rankings, Assets and Revenue: U.S. Corporations: *Fortune*, "The *Fortune* 500 Largest U.S. Corporations" (May 15, 1995); Foreign Corporations: *Fortune*, "The Global 500 List" (Aug. 17, 1995); Production: *Oil & Gas Journal*, "OGJ 200" (Sep. 9, 1995). Refining: Refining within the states: EIA, *Petroleum Supply Annual*, Table 34. "Refiners' Operable Atmospheric Crude Distillation Capacity as of January 1, 1995"; Refining in U.S. territories: EIA, *Petroleum Supply Annual*, Table 38, "Capacity of Operable Petroleum Refineries by State as of January 1, 1995". Data from *Fortune* and *Oil & Gas Journal* used by permission.

Note:

[1] *Fortune* ranking based on prior year's sales.

[2] Capacity represents ARCO's direct capacity (453,000) plus its controlling interest (50%) in Lyondell Petrochemical. Lyondell Petrochemical is engaged in a joint venture with Citgo, Lyondell-Citgo (265,000), of which Lyondell has a 87% interest. Due to ARCO's controlling interest in Lyondell it has been attributed the entirety of Lyondell's interest (87%) in the Lyondell-Citgo venture.

[3] *Fortune* includes only U.S. based companies in its *Fortune* 500 ranking. Foreign companies' ranks are projections based on where their revenues would have placed them in the *Fortune 500* had they been included in that list. These companies were included in "The Global 500 List". Their rank within the list is: BP (31), PDVSA (113), Fina (318), and Royal Dutch/Shell (10).

[4] Capacity represents PDVSA various interests. PDVSA directly owns Citgo (503,000). Citgo is engaged in a joint venture with Lyondell, Lyondell-Citgo (265,000). Citgo is attributed its 13% interest of Lyondell-Citgo. In addition, PDVSA is engaged in a 50/50 joint venture with Unocal, Uno-Ven Company (147,000); half of the capacity is attributed to PDVSA.

Table 4-3 *(continued)*

[5] The revenues and assets for du Pont's "Petroleum" segment is $17,203 million and $11,961 million, respectively. Source: E I du Pont de Nemours, *Form 10-K*, 64-65 (1994). On August 6, 1999, du Pont divested its remaining ownership interests in Conoco; from that date, Conoco was treated as an Oil Merger Sample firm and du Pont's transactions ceased to be included in the sample. On August 6, 1999 Du Pont completed divestiture of Conoco and ceased to be an Oil Merger Sample firm.

[6] Capacity represents Shell's direct capacity (761,000), plus its various interests. Shell has a 50/50 joint venture with Pemex, Deer Park Partnership (215,900); half of the capacity is attributed to Shell.

[7] Capacity represents Texaco's direct refinery holdings (350,600) plus its interest in Star Enterprise. Star Enterprise (600,000) is 50/50 joint venture with the Saudi Aramco; Texaco is attributed with its 50% interest.

[8] Capacity represents Unocal's direct refinery holdings (220,700) plus its interest in Uno-Ven. Uno-Ven (147,000) is a 50/50 joint venture between Unocal and PDVSA; each is attributed half of the capacity. In March 1997, Unocal sold its interest in Uno-Ven to PDVSA and the remainder of its refining and marketing assets to Tosco Corp. and ceased to be an Oil Merger Sample company.

Table 4-4 – Oil Merger Sample Companies' Basic Financial and Petroleum Information 2000-2001

Common or Trade Name	Parent(s)	1/1/2000 U.S. Refining Capacity (b/cd)	1999 U.S. Crude Oil Production (mmbbls)	2000 *Fortune* 500 Rank or Rank Equivalent [1]	1999 Sales ($ Mill.)	1999 Assets ($ Mill.)
ARCO	Atlantic Richfield Corp.	511,720	169	136	13,176	26,272
BP Amoco	BP Amoco P.L.C.	1,429,500	275	7[2]	83,566	89,561
Chevron	Chevron Corp.	1,049,000	115	35	32,676	40,668
Citgo and affiliates	Petroleos de Venezuela (PDVSA)	1,158,553[3]	0	36[2]	32,648	49,990
Conoco	Conoco Inc.	523,000	27	74	20,817	16,375
Exxon Mobil	Exxon Mobil Corp.	2,007,940[4]	213	3	163,881	144,521
Marathon-Ashland Petroleum [5]	USX Corp.	935,000	53	51	25,610	22,962
Phillips Petroleum	Phillips Petroleum Co.	355,000	27	126	13,852	15,201
Shell Oil	Royal Dutch/Shell Company	989,320[6]	184	6[2]	105,366	113,883
Texaco	Texaco Inc.	606,150[7]	144	28	35,690	28,972
Tosco	Tosco Corp.	920,000	0	119	14,362	6,212
TotalFinaElf [8]	TotalFinaElf S.A.	237,000	0	15[2]	44,990	81,168
Ultramar Diamond Shamrock	Ultramar Diamond Shamrock Corp.	418,689	0	157	11,079	4,936

Source: Rankings, Assets, and Revenue: U.S. Corporations: *Fortune*, "*Fortune* 500 Largest U.S. Corporations" (Apr. 17, 2000); Foreign Corporations: *Fortune*,"*Fortune* Global 5 Hundred" (Jul. 2, 2000); Production: *Oil & Gas Journal*, "OGJ200" (Oct. 16, 2000). Refining: Refining within the states: EIA, *Petroleum Supply Annual*, Table 40, "Refiners' Operable Atmospheric Crude Distillation Capacity as of January 1, 2000"; Refining in U.S. territories: EIA, *Petroleum Supply Annual*, Table 38, "Capacity of Operable Petroleum Refineries by State as of January 1, 2000". Data from *Fortune* and *Oil & Gas Journal* used by permission.

Note:

[1] *Fortune* ranking based on prior year's sales.

[2] *Fortune* includes only U.S.-based companies in its *Fortune 500* ranking. Foreign companies' ranks are projections based on where their revenues would have placed them in the *Fortune 500* had they been included in that list. The companies were listed in the "*Fortune* Global 5 Hundred". Their rankings within that index are: BP Amoco (17), PDVSA (102), Royal Dutch/Shell (11), and TotalFinaElf (50).

[3] Capacity represents PDVSA's directly held refining capacity (164,700), plus its various interests. Citgo is a direct subsidiary of PDVSA; all its refinery capacity is attributed to the parent (541,000). Citgo owns 42% of Lyondell-Citgo (262,650) and PDVSA (owner of Citgo) is attributed its 42% interest in the capacity of the partnership. PDVSA also has a 50% interest in Hovensa LLC (495,000), a refinery in the Virgin Islands. In addition, PDVSA has a 50% interest in Chalmette Refining LLC (190,080) which is attributed to its capacity.

[4] Capacity represents ExxonMobil direct refinery capacity (1,912,900) plus its 50% interest in Chalmette Refining LLC. ExxonMobil is attributed 50% of the refinery's capacity (190,080).

[5] Ashland, Inc. owned 38% of Marathon-Ashland, LLC in 2000. On March 19, 2004, Marathon and Ashland announced that Marathon would acquire all of Ashland's interests in the venture.

[6] Capacity represents Shell's direct capacity (135,000), plus its various interests. Shell has interests in Equilon (748,000) and Motiva (852,400); Shell was attributed its interest of 56% and 35% respectively. In addition Shell has a 50% interest in the Deer Park Partnership (274,200) with Pemex.

[7] Capacity represents Texaco's interest in joint ventures, as Texaco has no direct refinery holdings. Texaco has 44% interest in Equilon (748,000) and a 32.5% interest in Motiva (852,400).

[8] TotalFinaElf sold a substantial part of its U.S. refinery capacity in August 2000 and ceased to be an Oil Merger Sample company.

Table 4-5 – Whole-Company Transactions $10 Million or More (Current Dollars) 1985-2001 (Transaction Values in Millions of Dollars)

	Acquisitions			Divestitures			
Year	Count	Average Value	Total	Count	Average Value	Total	Net
1985	1	2,451.9	2,451.9	0	0.0	0.0	2,451.9
1986	4	1,110.2	4,444.0	0	0.0	0.0	4,440.8
1987	2	3,875.0	7,750.0	1	7,600.0	7,600.0	150.0
1988	6	1,663.0	9,977.7	0	0.0	0.0	9,977.7
1989	4	186.6	746.5	0	0.0	0.0	746.5
1985-1989	17	1,492.2	25,366.9	1	7,600.0	7,600.0	17,766.9
1991	2	428.9	857.7	0	0.0	0.0	857.7
1992	1	242.0	242.0	0	0.0	0.0	242.0
1990-1994	3	366.6	1,099.7	0	0.0	0.0	1,099.7
1995	1	W	W	0	0.0	0.0	W
1996	1	W	W	0	0.0	0.0	W
1997	4	W	W	0	0.0	0.0	W
1998	6	13,430.0	80,579.8	1	73,077.0	73,077.0	7,502.8
1999	9	11,241.7	101,175.1	2	58,631.4	117,262.7	(16,087.6)
1995-1999	21	8,918.7	187,292.9	3	63,446.6	190,339.7	(3,046.8)
2000	9	9,435.7	84,921.2	1	29,300.0	29,300.0	55,621.2
2001	6	11,950.9	71,705.4	3	22,832.0	68,496.0	3,209.4
2000-2001	15	10,441.8	156,626.6	4	24,449.0	97,796.0	58,830.6
1985-2001	56	6,614.0	370,386.1	8	36,967.0	295,735.7	74,650.4
1985-1997	26	1,230.9	32,004.6	1	7,600.0	7,600.0	24,404.6
1998- 2001	30	11,279.4	338,381.5	7	41,162.2	288,135.7	50,245.8

Source: Compiled from FTC Oil Merger Study Database.

Note: ‘W’ denotes data withheld due to FTC confidentiality rules for HSR data.

**Table 4-6 – All Transactions $10 Million or More (Current Dollars)
1985-2001
(Transaction Values in Millions of Dollars)**

	Acquisitions			Divestitures			
Year	Count	Average Value	Total	Count	Average Value	Total	Net
1985	21	263.6	5,535.6	38	225.9	8,583.7	(3,048.1)
1986	19	358.8	6,817.4	38	166.2	6,314.5	502.9
1987	24	529.7	12,712.6	22	440.8	9,698.7	3,014.0
1988	33	545.1	17,989.6	27	370.1	9,991.7	7,997.9
1989	26	422.6	10,986.5	21	608.7	12,783.6	(1,797.1)
1985-1989	123	439.4	54,041.7	146	324.5	47,372.2	6,669.6
1990	26	125.6	3,264.4	27	185.2	5,001.5	(1,737.1)
1991	16	178.6	2,857.2	20	213.1	4,261.3	(1,404.1)
1992	17	156.3	2,657.1	37	134.8	4,987.5	(2,330.4)
1993	24	81.5	1,955.6	59	120.3	7,098.4	(5,142.8)
1994	10	92.8	928.0	33	169.2	5,583.1	(4,655.1)
1990-1994	93	125.4	11,662.3	176	153.0	26,931.8	(15,269.5)
1995	20	149.7	2,994.5	25	180.7	4,518.3	(1,523.8)
1996	27	460.2	12,425.9	49	327.5	16,046.8	(3,620.9)
1997	41	636.6	26,102.4	52	388.1	20,182.7	5,919.7
1998	44	2,264.5	99,639.6	44	2,283.4	100,468.6	(829.0)
1999	35	3,052.9	106,850.0	47	2,926.9	137,562.6	(30,712.6)
1995-1999	167	1,485.1	248,012.4	217	1,284.7	278,779.0	(30,766.6)
2000	41	2,653.2	108,780.1	52	1,208.6	62,847.9	45,932.2
2001	21	3,678.3	77,243.9	19	3,762.9	71,495.0	5,748.9
2000-2001	62	3,000.4	186,024.0	71	1,892.2	134,342.9	51,681.1
1985-2001	445	1,123.0	499,740.4	610	799.1	487,425.9	12,314.5
1985-1997	304	352.7	107,226.8	448	256.8	115,051.8	(7,824.9)
1998-2001	141	2,783.8	392,513.6	162	2,298.6	372,374.1	20,139.5

Source: Compiled from FTC Oil Merger Study Database.

Table 4-7 – Whole-Company Transactions $10 Million or More (1971 Dollars) 1985-2001 (Transaction Values in Millions of Dollars)

	Acquisitions			Divestitures			
Year	Count	Average Value	Total	Count	Average Value	Total	Net
1985	1	966.9	966.9	0	0.0	0.0	966.9
1986	2	848.9	1,697.8	0	0.0	0.0	1,697.8
1987	2	1,451.5	2,903.0	1	2,846.8	2,846.8	56.2
1988	6	602.5	3,614.9	0	0.0	0.0	3,614.9
1989	4	65.1	260.5	0	0.0	0.0	260.5
1985-1989	15	629.5	9,443.1	1	2,846.8	2,846.8	6,596.3
1991	2	139.0	278.0	0	0.0	0.0	278.0
1992	1	76.6	76.6	0	0.0	0.0	76.6
1990-1994	3	118.2	354.6	0	0.0	0.0	354.6
1995	1	W	W	0	0.0	0.0	W
1996	1	W	W	0	0.0	0.0	W
1997	4	W	W	0	0.0	0.0	W
1998	6	3,781.7	22,690.4	1	20,577.7	20,577.7	2,112.7
1999	5	5,610.5	28,052.7	2	16,275.0	32,549.9	(4,497.3)
1995-1999	17	3,078.2	52,329.8	3	17,709.2	53,127.6	(797.8)
2000	8	2,885.4	23,083.0	1	7,965.7	7,965.7	15,117.2
2001	6	3,173.9	19,043.7	3	6,063.8	18,191.3	852.4
2000-2001	14	3,009.0	42,126.7	4	6,539.3	26,157.1	15,969.6
1985-2001	49	2,127.6	104,254.1	8	10,266.4	82,131.5	22,122.6
1985-1997	24	474.4	11,384.4	1	2,846.8	2,846.8	8,537.6
1998- 2001	25	3,714.8	92,869.7	7	11,326.4	79,284.7	13,585.0

Source: Compiled from FTC Oil Merger Study Database.

Note: ‘W’ denotes data withheld due to FTC confidentiality rules for HSR data.

Table 4-8 – All Transactions $10 Million or More (1971 Dollars)
1985-2001
(Transaction Values in Millions of Dollars)

	Acquisitions			Divestitures			
Year	Count	Average Value	Total	Count	Average Value	Total	Net
1985	17	127.0	2,159.3	35	96.2	3,365.5	(1,206.2)
1986	11	234.1	2,575.0	29	82.0	2,377.9	197.2
1987	19	248.9	4,728.7	16	224.8	3,596.3	1,132.4
1988	27	239.3	6,462.4	20	178.5	3,570.9	2,891.5
1989	20	189.8	3,796.7	17	260.6	4,430.0	(633.3)
1985-1989	94	209.8	19,722.1	117	148.2	17,340.5	2,381.5
1990	19	54.8	1,042.1	19	85.7	1,628.9	(586.7)
1991	11	80.1	880.7	16	84.7	1,355.3	(474.6)
1992	16	52.2	835.7	30	51.2	1,536.9	(701.2)
1993	13	40.8	530.2	42	49.2	2,064.4	(1,534.2)
1994	5	50.1	250.3	27	61.5	1,660.5	(1,410.1)
1990-1994	64	55.3	3,539.1	134	61.5	8,245.9	(4,706.8)
1995	14	60.7	849.3	18	72.1	1,297.0	(447.7)
1996	15	235.5	3,532.5	39	117.9	4,596.9	(1,064.3)
1997	34	217.4	7,391.0	45	126.8	5,707.6	1,683.4
1998	36	777.7	27,999.0	36	784.5	28,243.3	(244.3)
1999	21	1,407.3	29,554.0	37	1,030.3	38,122.6	(8,568.7)
1995-1999	120	577.7	69,325.8	175	445.5	77,967.4	(8,641.6)
2000	34	868.8	29,537.6	51	334.9	17,079.0	12,458.6
2001	19	1,078.9	20,499.8	14	1,354.4	18,961.5	1,538.4
2000-2001	53	944.1	50,037.5	65	554.5	36,040.5	13,997.0
1985-2001	331	430.9	142,624.4	491	284.3	139,594.3	3,030.1
1985-1997	221	158.5	35,034.0	353	105.3	37,187.9	(2,153.9)
1998-2001	110	978.1	107,590.4	138	742.1	102,406.4	5,184.0

Source: Compiled from FTC Oil Merger Study Database.

Table 4-9 – Whole-Company Transactions $100 Million or More (1971 Dollars) 1985-2001 (Transaction Values in Millions of Dollars)

	Acquisitions			Divestitures			
Year	Count	Average Value	Total	Count	Average Value	Total	Net
1985	1	966.9	966.9	0	0.0	0.0	966.9
1986	1	1,684.5	1,684.5	0	0.0	0.0	1,684.5
1987	1	2,846.8	2,846.8	1	2,846.8	2,846.8	0.0
1988	4	875.3	3,501.1	0	0.0	0.0	3,501.1
1989	1	166.30	166.30	0	0.0	0.0	166.3
1985-1989	8	1,145.7	9,165.7	1	2,846.8	2,846.8	6,318.9
1991	1	261.5	261.5	0	0.0	0.0	261.5
1990-1994	1	261.5	261.5	0	0.0	0.0	261.5
1996	1	405.1	405.1	0	0.0	0.0	405.1
1997	3	386.3	1,159.0	0	0.0	0.0	1,159.0
1998	4	5,662.2	22,648.8	1	20,577.7	20,577.7	2,071.1
1999	4	7,005.2	28,020.7	2	16,275.0	32,549.9	(4,529.2)
1995-1999	12	4,352.8	52,233.6	3	17,709.2	53,127.6	(894.0)
2000	5	4,596.1	22,980.5	1	7,965.7	7,965.7	15,014.7
2001	4	4,741.0	18,964.0	3	6,063.8	18,191.3	772.7
2000-2001	9	4,660.5	41,944.5	4	6,539.3	26,157.1	15,787.4
1985-2001	30	3,453.5	103,605.3	8	10,266.4	82,131.5	21,473.8
1985-1997	13	845.5	10,991.3	1	2,846.8	2,846.8	8,144.5
1998- 2001	17	5,447.9	92,614.0	7	11,326.4	79,284.7	13,329.3

Source: Compiled from FTC Oil Merger Study Database.

Table 4-10 – All Transactions $100 Million or More (1971 Dollars) 1985-2001 (Transaction Values in Millions of Dollars)

	Acquisitions			Divestitures			
Year	Count	Average Value	Total	Count	Average Value	Total	Net
1985	5	360.8	1,804.1	9	256.2	2,306.1	(502.0)
1986	5	474.4	2,372.0	5	281.0	1,405.0	967.0
1987	6	677.3	4,063.5	4	836.5	3,346.1	717.5
1988	11	540.1	5,941.2	5	609.2	3,045.8	2,895.4
1989	9	382.5	3,442.1	6	672.2	4,033.4	(591.3)
1985-1989	36	489.5	17,623.0	29	487.5	14,136.3	3,486.6
1990	3	145.7	437.2	3	350.4	1,051.1	(613.9)
1991	3	198.8	596.5	4	226.5	906.1	(309.6)
1992	2	188.9	377.8	2	304.6	609.1	(231.3)
1993	2	143.4	286.9	6	124.5	747.3	(460.4)
1994	0	0.0	0.0	5	205.5	1,027.4	(1,027.4)
1990-1994	10	169.8	1,698.4	20	217.0	4,341.0	(2,642.6)
1995	4	144.3	577.1	4	219.3	877.1	(300.1)
1996	9	377.1	3,393.9	8	416.6	3,332.7	61.2
1997	17	391.8	6,660.3	13	333.2	4,331.3	2,329.0
1998	15	1,828.1	27,422.1	15	1,825.9	27,388.2	33.9
1999	7	4,140.9	28,986.4	11	3,368.8	37,056.5	(8,070.1)
1995-1999	52	1,289.2	67,039.8	51	1,431.1	72,985.9	(5,946.1)
2000	17	1,697.8	28,862.6	16	981.1	15,697.1	13,165.4
2001	10	2,013.5	20,134.7	6	3,107.0	18,641.7	1,492.9
2000-2001	27	1,814.7	48,997.2	22	1,560.9	34,338.8	14,658.4
1985-2001	125	1,082.9	135,358.4	122	1,031.2	125,802.1	9,556.3
1985-1997	76	394.1	29,952.6	74	365.1	27,018.5	2,934.1
1998-2001	49	2,151.1	105,405.8	48	2,058.0	98,783.6	6,622.2

Source: Compiled from FTC Oil Merger Study Database.

Table 4-11 – Billion-Dollar* Transactions by Large Petroleum Companies 1985-2001 (Transaction Values in Millions of Dollars)

Year	Value (Current Dollars)	Value (1971 Dollars)	Buyer	Seller	Assets Category	Transaction Description
1986	4,365.5	1,684.5	USX-Marathon	Texas Oil Gas Corp.	Upstream Petroleum	The merger of TXO and the Marathon subsidiary of USX
1987	7,600.0	2,846.8	BP	Standard Oil Co. minority public shareholders	Integrated Petroleum	Complete control of the remaining 45% of BP's U.S. associate, Standard Oil. Co.
1988	4,200.0	1,521.7	AMOCO	Dome Petroleum Ltd.	Upstream Petroleum	All the outstanding stock and certain indebtedness of Dome
1988	4,159.7	1,507.1	BP	Britoil	Upstream Petroleum	The remaining shares of Britoil not previously owned by BP
1988	3,900.0	1,413.0	Management LBO	Mobil	Non-Energy	Montgomery Ward & CO. department store chain
1989	4,311.5	1,504.6	RTZ Corp.	BP	Non-Energy	Most of BP's minerals interests
1989	4,150.0	1,448.3	Exxon	Texaco	Integrated Petroleum	Imperial Oil Ltd. (Exxon affiliate) acquired the outstanding stock of Texaco Canada
1996	5,000.0	1,453.0	BP	Mobil	Downstream Petroleum	Joint venture combining BP and Mobil's European fuels and lubricants operations
1997	4,908.0	1,399.0	AMOCO	Shell Oil Co.	Upstream Petroleum	Altura Energy Ltd. was established to operate the combined oil and gas producing properties of Amoco and Shell Oil Company in west Texas and southeast New Mexico
1998	3,945.0	1,110.9	ARCO	Union Texas Petroleum Holdings, Inc.	Upstream Petroleum	ARCO purchased the outstanding common stock of Union Texas
1998	5,900.0	1,661.4	Lyondell	ARCO	Non-Energy	ARCO tendered its entire interest of 80 million shares of ARCO Chemical common stock to Lyondell
1998	73,077.0	20,577.7	BP	Amoco	Integrated Petroleum	BP merged with AMOCO, which became a wholly-owned subsidiary of BP

Table 4-11 *(continued)*

Year	Value (Current Dollars)	Value (1971 Dollars)	Buyer	Seller	Assets Category	Transaction Description
1998 - 1999	15,477.0	4,517.7	Conoco (public stock offering, spin-off)	du Pont	Integrated Petroleum	In 1998, 191,456,427 shares of Class A common stock were sold in an initial public offering, which represented about 30% of Conoco. In 1999, the balance of Conoco was spun-off to du Pont's shareholders..
1998	3,812.0	1,073.4	Shell Oil Co.	Texaco Inc.	Downstream Petroleum	Joint venture between Texaco and Shell that combined their U.S. refining and marketing businesses
1999	98,296.0	27,285.1	Exxon	Mobil	Integrated Petroleum	All the outstanding shares of Mobil common stock
1999	18,966.7	5,264.8	Total Petroleum SA	PetroFina	Integrated Petroleum	Total acquired all of PetroFina
2000	29,300.0	7,965.7	BP Amoco	Atlantic Richfield	Integrated Petroleum	BP acquired all of Atlantic Richfield
2000	4,800.0	1,305.0	BP Amoco	Burmah-Castrol	Downstream Petroleum	Burmah Castrol, a global marketer of specialized lubricant and chemical products and services
2000	6,000.0	1,631.2	Phillips	Chevron	Non-Energy	Joint venture to combine the worldwide olefin and polyethylene production of Phillips and Chevron
2000	7,479.0	2,033.3	Phillips	ARCO	Upstream Petroleum	ARCO's exploration and production assets in Alaska
2000	48,322.0	13,139.9	TotalFina	Elf Aquitaine	Integrated Petroleum	TotalFina acquired all of Elf Aquitaine
2001	59,396.0	15,774.5	Chevron Corp.	Texaco Inc.	Integrated Petroleum	Chevron and Texaco merged their entire firms
2001	4,571.0	1,214.0	Conoco	Gulf Canada Resources	Upstream Petroleum	Gulf Canada is a Canadian-based independent exploration and production company, with primary operations in western Canada, Indonesia, the Netherlands, and Ecuador
2001	7,000.0	1,859.1	Phillips	Tosco Corp.	Downstream Petroleum	Phillips acquired all of Tosco Corp.

Source: Compiled from FTC Oil Merger Study Database.

Note: *Selection criteria based on transactions valued at $1 billion or more (1971 dollars).

Table 4-12 – Total Revenues and Assets of Leading Petroleum Companies Included in Oil Merger Sample 1985-2001 (Values in Millions of Dollars)

	Current Dollars		1971 Dollars	
Year	Revenues	Assets	Revenues	Assets
1984	538,015	435,855	229,846	186,202
1985	538,701	455,030	223,113	188,458
1986	414,081	463,918	155,407	178,648
1987	455,687	486,291	164,745	176,347
1988	464,505	479,137	176,745	182,312
1989	504,812	490,703	185,023	179,852
1990	603,672	535,738	212,970	189,004
1991	577,140	529,584	196,457	180,269
1992	567,625	532,587	188,632	208,729
1993	534,992	522,901	173,609	169,686
1994	552,936	553,475	175,769	175,941
1995	624,339	587,050	194,239	182,621
1996	721,427	626,185	220,179	190,961
1997	688,255	602,049	211,702	184,958
1998	543,600	610,415	173,374	191,024
1999	597,713	640,722	174,250	186,788
2000	894,496	704,123	255,403	201,046
2001	833,296	689,126	232,427	192,215

Source: *Fortune 500* (1985-2002). Data from *Fortune* used by permission.

Table 4-13 – Value of Acquisitions, Divestitures, and Net Acquisitions (Acquisitions less Divestitures) of Leading Petroleum Companies as a Percentage of Their Prior Year Sales and Assets 1985-2001

	Acquisitions		Divestitures		Net Acquisitions	
Year	Sales	Assets	Sales	Assets	Sales	Assets
1985	1.0	1.3	1.6	2.0	-0.6	-0.7
1986	1.3	1.5	1.2	1.4	0.1	0.1
1987	3.2	2.8	2.5	2.2	0.7	0.6
1988	4.3	4.0	2.4	2.2	1.9	1.8
1989	2.4	2.3	2.8	2.7	-0.4	-0.4
1990	0.6	0.7	1.0	1.0	-0.3	-0.4
1991	0.5	0.5	0.7	0.8	-0.2	-0.3
1992	0.5	0.5	0.9	0.9	-0.4	-0.4
1993	0.3	0.3	1.2	1.1	-0.9	-0.8
1994	0.2	0.2	1.0	1.1	-0.9	-0.9
1995	0.5	0.5	0.8	0.8	-0.3	-0.3
1996	2.0	2.1	2.6	2.7	-0.6	-0.6
1997	3.6	4.2	2.8	3.2	0.8	0.9
1998	14.1	16.1	14.2	16.3	-0.1	-0.1
1999	18.2	16.5	21.5	19.6	-3.3	-3.0
2000	18.2	17.0	10.5	9.8	7.7	7.2
2001	8.6	11.0	8.0	10.2	0.6	0.8

Source: FTC Oil Merger Study Database; *Fortune 500* (1985-2002). Data from *Fortune* used by permission.

Table 4-14 – Measures of Merger Activity for All Industries and for Oil and Gas Industry 1985-2003

Year	Oil & Gas Mergers	Total Mergers	Value of Oil & Gas Mergers ($ millions)	Total Value of Mergers ($ millions)	Percentage of All Mergers Accounted for by Oil & Gas Industry	Percentage of Total Value of All Mergers Accounted for by Oil & Gas Industry	Size Ratio of Average Oil and Gas Transaction Relative to All Transactions
1985	86	3,001	23,160	179,768	2.9	12.9	4.5
1986	58	3,336	3,247	173,137	1.7	1.9	1.1
1987	30	2,032	15,442	163,686	1.5	9.4	6.4
1988	39	2,258	5,607	246,875	1.7	2.3	1.3
1989	42	2,366	9,370	221,085	1.8	4.2	2.4
1990	23	2,074	2,540	108,152	1.1	2.3	2.1
1991	47	1,877	4,487	71,164	2.5	6.3	2.5
1992	47	2,574	3,063	96,688	1.8	3.2	1.7
1993	38	2,663	2,027	176,400	1.4	1.1	0.8
1994	42	2,997	3,551	226,671	1.4	1.6	1.1
1995	52	3,510	5,476	356,016	1.5	1.5	1.0
1996	56	5,848	9,274	494,962	1.0	1.9	2.0
1997	85	7,800	16,152	657,063	1.1	2.5	2.3
1998	62	7,809	154,125	1,191,861	0.8	12.9	16.3
1999	69	9,278	37,349	1,425,885	0.7	2.6	3.5
2000	92	9,566	67,202	1,325,734	1.0	5.1	5.3
2001	118	8,290	51,264	699,398	1.4	7.3	5.1
2002	96	7,303	10,339	440,701	1.3	2.3	1.8
2003	83	7,983	11,715	504,596	1.0	2.3	2.2

Source: Count of Oil & Gas Mergers: *Mergerstat Review*, “Ranking of Industry Classifications: Number of Transactions” (1986-2004); Value of Oil & Gas Mergers: *Mergerstat Review*, “Ranking of Industry Classifications: Dollar Value Paid” (1986-2004); Count of All Mergers: *Mergerstat Review*, Table 1-1, “Net Merger And Acquisition Announcements: 1963-2003” (2004); Value of All Mergers: *Mergerstat Review*, Table 1-4, “Purchase Price ($ in Millions): 1984-2003” (2004). Data from *MergerStat Review* used by permission of FactSet Mergerstat LLC.

Table 4-15 Categorization of Claimed Efficiencies in Selected Transactions

Category of Efficiency	Transaction Claiming Efficiency	Transaction Type	Comments
Operating Synergies	BP/Amoco	Upstream and Downstream	Total efficiency claim of $2 billion. Unspecified reductions in staff. Phase out Amoco brand.
	BP/ARCO	Upstream and Downstream	Total efficiency claim of $800 million: $510 million from E&P, $110 million from refining & marketing, $180 million from corporate costs. 2,000 job cuts.
	BP/Castrol	Upstream and Downstream	$260 million claimed. 1,700 job cuts.
	Chevron/ Texaco	Upstream	Total efficiency claim of $1.8 billion: $700 million from E&P, $300 million from corporate costs. 4,500 job cuts.
	Conoco/ Phillips	Upstream and Downstream	$1.25 billion claimed, including $400 million E&P, $200 million corporate & supply chain.
	Marathon/ Ashland	Downstream	
	Shell/ Texaco	Downstream	Total efficiency claim of $3 billion.
Refinery or Distribution Integration	Exxon/ Mobil	Upstream and Downstream	$1.4 billion in improved capacity utilization, optimization of feedstocks in integrated refinery & pipeline system. Total efficiency claim of $4.6 billion, including $1.4 billion E&P, $2.4 billion refining & marketing. 16,500 job cuts.
	Marathon/ Ashland	Downstream	
	Phillips/ Tosco	Upstream and Downstream	Total efficiency claim of $280 million.
	Valero refinery acquisitions	Downstream	Total efficiency claim of $400 million. From UDS acquisition, $55 million. From other refinery acquisitions.
Crude Oil Scale Economies	Kerr-McGee/ Oryx	Upstream	Total efficiency claim of $100 million.
	Devon acquisitions	Upstream	
	Pioneer Natural Resources	Upstream	

Sources: Company statements and reports.

Appendix to Chapter 4: Mergers and the Petroleum Industry Since 1985: The Empirical Data

I. Methodology

A. Definition of "Large Petroleum Company"

The 1982 and 1989 Merger Reports measured merger activity for the 16 LPCs that met certain selection criteria.[1] These Merger Reports followed the same LPCs throughout their study periods, making adjustments as necessary to compensate for changes in ownership. Because of substantial structural change within the industry over the much longer period of 1985 to 2001, using a fixed set of LPCs would not be appropriate for the present Report. Therefore, in the current study a new set of LPCs is defined every five years, with the selected firms serving as the LPCs for merger activity analysis over the next five-year interval. Thus, there are four time periods: 1985-1989, 1990-1994, 1995-1999, and 2000-2001, with a slightly different group of companies for each period. The criteria for selecting LPCs are similar to those of the earlier Merger Reports, with a few differences dictated by changes in the domestic petroleum industry. Each company is still required to possess at least 200 MBD of refining capacity in the U.S. or its territories. While the earlier Merger Reports required companies to be listed in the *Fortune* 100, the current Report requires that companies be "*Fortune*-100-equivalent." This change was made because of changes in industry structure and in the criteria for inclusion in the *Fortune* listing of firms.

For 1985-1994, a *Fortune*-100-equivalent firm was defined as any firm with at least 200 MBD of refining capacity in the U.S. or its territories and with revenues as great as any of the largest 100 publicly-held U.S.-based industrial firms. The scope of the *Fortune* list changed in 1994 from just domestically based, publicly-held

[1] Firms qualified for inclusion as LPCs in the 1982 and 1989 Merger Reports if they (1) were listed among the *Fortune* 100 and (2) had both large domestic crude oil production and large refining activities relative to total firm operations. The Merger Reports excluded "seven *Fortune* 100 [firms] which possessed significant crude production or refining operations but . . . [whose] petroleum related activities were small relative to their other activities." 1982 Merger Report 20. Since the *Fortune* 100 included only U.S.-based firms, the Merger Reports excluded companies headquartered abroad. An examination of the companies labeled "LPCs" and those labeled "petroleum-related" in the 1982 Merger Report indicates that LPCs had to be integrated into both crude oil production and refining and marketing. The 1982 Merger Report's implied requirements were that a firm have at least 200 MBD of domestic refining capacity and be included among the top 50 domestic crude oil and natural gas producers. Finally, the absence of financial reporting requirements at the divisional level and an assumption that merger activity by a conglomerate that acquired an LPC might be different from that of a more traditional oil company (even though these firms might be diversified into non-petroleum activities) led the 1982 Merger Report to exclude transactions by conglomerates subsequent to their acquisitions of LPCs.

industrial companies to include *all* domestically based, publicly-held companies. As a result, only about half the industrial companies that had been on the *Fortune* 100 list remained there. Starting in 1995, the minimum revenue required to be a *Fortune*-100-equivalent company was adjusted. For 1995 and 2000, the revenue of the 200th company on the *Fortune* list was used as the minimum revenue required to be a *Fortune*-100-equivalent company.

Using the definition of *Fortune*-100-equivalent companies has two principal effects on the set of LPCs compared to the earlier Merger Reports: inclusion of foreign firms with U.S. refining assets and inclusion of Southland Corporation, a domestically based, non-industrial firm. The earlier Merger Reports included only U.S.-based firms, but the increasing globalization of the petroleum industry over the past two decades has caused some firms headquartered in foreign countries to have significant shares in U.S. petroleum markets. Therefore, British Petroleum ("BP"), Petroleos de Venezuela ("PDVSA," the Venezuelan state petroleum company), Royal Dutch/Shell, and TotalFinaElf (previously Fina or Petrofina) are included in some sample periods of the current Report, which requires only that an LPC have significant refining capacity located in the U.S. or its territories. The change to the *Fortune*-100-equivalent criteria also admits Southland, the parent corporation of Citgo until January 1990, which prior to 1994 was listed in the *Fortune* Service 500 and therefore not considered an industrial firm.

This Report also drops the requirement of the earlier Merger Reports that LPCs be among the top 50 U.S. crude oil and natural gas producers. This change reflects the diminishing importance of domestic crude oil production and the increasing importance of large, nonintegrated oil companies.[2] Removal of this requirement allowed Southland and PDVSA (parents of Citgo) and Coastal (primarily a refiner) into this study's samples for the earlier periods, and Tosco (exclusively a refiner) into samples for the later periods.[3] The requirement that firms' activities be publicly reported was retained.[4]

Another difference from the earlier Merger Reports in the selection criteria for LPCs is that the present Report includes LPC conglomerate firms as long as they were *Fortune*-100-equivalent and owned sufficient domestic refining assets. The 1989 Merger Report had dropped Conoco

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2 EIA also ceased publishing this information on a regular basis, making consistent selection of the sample more difficult.

3 When Occidental Petroleum purchased Cities Service in 1982, Occidental promptly separated the acquired firm into two entities: crude oil production, and refining and marketing. Occidental retained the crude production but sold the refining and marketing operations to Southland Corporation, operators of the 7-Eleven convenience stores. Because Cities Service was no longer an integrated petroleum company, it no longer qualified as an LPC in the earlier Merger Reports. PDVSA is heavily integrated into crude oil production in Venezuela but not in the U.S.

4 PDVSA's public reporting has varied from time to time, depending in part on the policies of the Venezuelan government. However, to the extent that its transactions involved U.S.-based entities, they have been widely reported. Koch Industries, Inc., a privately held firm, apparently would have qualified as a LPC in all periods had it been a publicly-reported firm. (Koch appears to be the only such privately held firm.)

from its sample due to its purchase by DuPont in 1981; the 1989 Merger Report also deleted Cities Service because of its acquisition by Occidental Petroleum in 1982. The present Report includes among its selected LPCs DuPont (parent of Conoco), USX (parent of Marathon), and PDVSA and Southland (parents of Citgo). [5] Including LPC conglomerates provides more complete coverage of transactions among oil-related entities.[6]

B. Definition of "Merger Activity"

The 1982 and 1989 Merger Reports differentiated between "whole-company acquisitions," which eliminate independent business entities, and "all acquisitions," which include both whole-company transactions and acquisitions of some part of another firm's assets. Following the earlier Merger Reports, the current study includes a partial acquisition if it involves the acquisition of a division or set of business operations – a "going concern" – but excludes an "asset-only transaction."[7] Acquisitions of crude oil exploration concessions and new leases were also excluded, but include crude oil asset acquisitions involving current production. Finally, only transactions with known prices over $10 million are included. This threshold is consistent with the earlier Merger Reports and allows us to include transactions that might be significant in smaller regional or emerging markets, whereas indexing the minimum value for a "material" transaction would eliminate some small transactions over time.[8]

Formation of joint ventures and alliances was analyzed for inclusion on a case-by-case basis. The data include joint ventures that appeared to combine existing business operations, *i.e.*, those that effectively merged going concerns. Joint ventures to develop new lines of business or conduct exploration and development activities beyond exploiting still substantially-producing fields were excluded. Corporate reorganizations and financing vehicles, including the creation of subsidiaries that were partly owned by outsiders,

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5 A concern that the motivations for acquisitions by the new conglomerate parents of LPCs would be qualitatively different from those of traditional oil companies prompted the exclusion from the earlier Merger Reports of the post-acquisition activities of those entities. Another reason why the earlier Merger Reports did not include mergers and acquisitions by conglomerates was that the earlier Reports computed a number of financial ratios about the transactions, such as the value of acquisitions relative to funds from operations and relative to balance sheet or income statement items of the acquiring firm. The authors believed that exclusion of conglomerate parents from the sample would increase the comparability of their data series. 1989 Merger Report 33-34. Because of the much longer time period covered by the present Report, those financial series were not compiled.

6 At the same time, this change causes us to include transactions by conglomerate parent companies that are seemingly unrelated to their oil activities. Nevertheless, several traditional petroleum companies also engaged in non-oil-related transactions. For example, BP acquired several animal nutrition firms, Amoco invested in microelectronics firms, and Ashland made multiple purchases of paving contractors and chemical distributors.

7 Types of assets excluded under this limitation included ordinary-course-of-business sales and purchases of commercial real estate, oil tankers, drilling rigs, undeveloped acreage, geologic data and other intellectual property, and refinery equipment.

8 Approximately 1,500 transactions were identified where no value of the transaction was publicly announced. These transactions were probably relatively small in value. Based on the description of the assets conveyed and valuations in similar contemporary transactions, however, it is likely that they would have qualified for inclusion in the data set had their values been publicly available. The analysis here thus understates merger activity.

were not included. To the extent that such entities appeared to continue to act in concert with the originator, however, subsequent acquisitions and divestitures by those entities were included in the sample.[9] For example, ARCO created Vastar in 1994 to operate ARCO's natural gas properties and sold approximately 18% of Vastar's stock to the public. The creation of Vastar was not treated as a divestiture by ARCO. Acquisitions and divestitures by Vastar were included because it was judged that ARCO was likely to have retained substantial influence over Vastar's major decisions, such as engaging in acquisitions or divestitures.

C. Sources of Information

As with the earlier Merger Reports, the primary data sources for merger transactions were company financial filings with the Securities and Exchange Commission (principally Forms 10-K or 20-F and Annual Reports to Shareholders) and merger and divestiture actions reported in Moody's *Industrial Manual*. For nearly all transactions that were identified in these two sources, the Lexis/Nexis news database was searched for press releases issued by the parties and contemporaneous news accounts in major financial publications to obtain additional transaction details. When multiple conflicting accounts of the same transaction were encountered, the company's SEC filings were given precedence.[10] The Lexis/Nexis database for press releases (all years), as well as S&P News (1990-1999) and *Bloomberg News* (2000-2001), were also searched for articles that referenced the sample companies and terms that were synonyms for "merger" and "joint venture."[11] Data from *MergerStat* acted as a further check on the completeness of the search.[12] Reports of proposed transactions or negotiations were not included unless confirmation that the transactions were consummated was located.

To confirm information from other sources, to help focus searches for publicly-announced transactions, and to provide transaction values for a limited number of transactions when such values were not announced publicly, we reviewed information in the FTC's HSR database. Because of statutory restrictions on releasing information derived from firms' filings under the HSR Act, such information is not disclosed in this Report on a transaction-specific basis or in a disaggregated form that might allow identification of

9 To the extent possible, transactions of any non-consolidated, publicly-reported entity in which an LPC held a 20% or greater interest are included. Use of various limited partnership arrangements, which were treated under the equity method of accounting, may have prevented inclusion of a number of significant transactions that would have met our criteria but were not required to be publicly reported under these arrangements. Use of these partnership arrangements became widespread beginning in the late 1990s.

10 On occasion, annual financial filings contain blanket statements of a type such as "the company sold operating properties in the Western states . . .," in which case transaction-specific reports were given precedence.

11 For 1985 and 1986, a broader search in the Lexis/Nexis database was conducted using the same search terms because computer-searchable data for SEC filings and the FTC's Hart-Scott-Rodino ("HSR") databases (see discussion in the following paragraph) were not available for those years.

12 Mergerstat, *Mergerstat Review* (FactSet Mergerstat, LLC, Annual), 1984-2000.

transaction-specific data. About 450 (mainly small) transactions in the HSR database apparently were not specifically announced publicly by the parties.[13] In keeping with the earlier Merger Reports, which covered only publicly-reported transactions, these transactions were not included in the present study.

II. Descriptions of LPCs Included in the Analysis

Tables 4-1 through 4-4 identify the LPCs in the four sample periods. Several firms remained on the list of LPCs throughout the entire period. These include BP, ARCO,[14] Shell, Chevron, Texaco,[15] Exxon/Mobil,[16] Conoco, Phillips,[17] Citgo, and Marathon.[18] Substantial turnover occurred, however, and the number of firms dropped from 18 for each of the first three sample periods to 13 for the final period. Seven firms in the 1985-1989 sample had disappeared as independent entities by 2000. Amoco was acquired by BP, and Mobil merged with Exxon. Marathon and Ashland formed the Marathon Ashland joint venture in late 1999, with Ashland putting all of its downstream assets into the joint venture and simultaneously selling off its upstream assets. Unocal sold its domestic refining and marketing operations to Tosco. Amerada Hess, Ashland, Coastal, and Sunoco were dropped because they were no longer *Fortune*-100-equivalent firms, reflecting in part the decline in petroleum industry sales revenues relative to the overall economy. Tosco and Ultramar Diamond Shamrock, domestically based companies not integrated into oil and gas production, were added in 2000.

Several other LPCs underwent significant ownership changes. Conoco became independent again in 1998 when DuPont sold its shares in one of the largest public stock offerings as of that date. Southland transferred ownership of Citgo to PDVSA in a two-step transaction: PDVSA bought a 50% interest in Citgo in 1986 and the remainder in 1990. The Belgium-based firm, Fina, joined the list in 1995 after expanding its U.S. refining capacity in

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[13] Matching descriptions among various sources was not always straightforward. The financial disclosures of the buyers and sellers often did not mention the name of the opposite party to the transaction and often used differing names to describe the same asset. For example, one company reported buying facilities in central Wyoming, without naming the seller, and another reported selling a Riverton, Wyoming gas plant, without naming the buyer; whether these firms were reporting the same transaction was unclear. As noted above, the financial disclosure documents often contained blanket statements to the effect that, e.g., the company had acquired marketing properties in the Western states. Whether this referred in part to a specific HSR transaction that described markets in both the South Central and Southwestern regions was an inference that we were cautious in making, absent other confirmation.

[14] BP acquired ARCO during 2000. Prior to the acquisition, each was an independent LPC.

[15] Chevron and Texaco merged in 2001. Prior to the acquisition, each was an independent LPC.

[16] Exxon and Mobil merged in 1999. Prior to this, Exxon and Mobil were each independent LPCs.

[17] Conoco and Phillips merged in 2002; this transaction is not included in our database, which ends in 2001.

[18] Royal Dutch/Shell and PDVSA are multinationals headquartered abroad and, as noted earlier, were not included under the criteria of the earlier Merger Reports. The earlier Reports included Shell Oil Company (U.S.), which until 1983 was a separate, publicly traded U.S. firm with a minority public ownership. The Royal Dutch/Shell parents bought out publicly traded interests in 1983.

the early 1990s through internal growth. In early 1999 Total Petroleum, SA, acquired Fina's Belgian parent, Petrofina, and later that year acquired the other major French oil firm, Elf Aquitaine, thus becoming TotalFinaElf on the 2000 list.[19]

For the LPCs that were integrated into crude oil production over the entire period, per-firm average domestic crude oil production declined until the late 1990s, when the per-firm average increased at least in part due to consolidation. Even so, per-firm average domestic crude oil production remained well below that of the 1970s. Per-firm average domestic crude oil production was 116 MBD in 1984 (down from 394 MBD for the 1970 LPCs), 120 MBD in 1989, 93 MBD in 1994, and 134 MBD in 1999.[20] The number of nonintegrated firms increased from one (Citgo) in the 1985-1989 period to four (Citgo, Tosco, TotalFinaElf and Ultramar Diamond Shamrock) in the 2000-2001 period. Per-firm domestic refining capacity averaged 676 MBD in 1985 (up from 636 MBD in 1971), 680 MBD in 1990, 631 MBD in 1995, and 776 MBD in 2000.[21] A series of mergers among large refiners resulted in the increase in average per-firm capacity in the last interval.

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[19] TotalFinaElf sold its principal U.S. refinery in August 2000 and ceased to meet the criteria for being a LPC. Subsequent transactions by this firm are therefore not included in the sample.

[20] If all LPCs were included in the sample, including those without any crude production, average crude oil production was 110 MBD in 1984 (down from 394 MBD for the 1970 LPCs), 106 MBD in 1989, 82 MBD in 1994, and 93 MBD in 1999.

[21] All capacities measured at the beginning of the reported calendar year.

Chapter 5

Structural Change in Crude Oil Production and Reserves

Crude oil is the primary input into the production of gasoline and other refined petroleum products. Changes in supply conditions and prices for crude oil explain most movements in gasoline prices. This chapter analyzes the structure of the crude oil industry and its impact on crude oil pricing to U.S. refiners. Section I discusses the relevant market for crude oil in merger investigations and examines trends in the sources of crude oil used by U.S. refiners. Sections II and III provide information on worldwide concentration in ownership of crude oil production, and discuss the ability of OPEC to affect world crude prices. Section IV provides an analysis of domestic concentration in crude oil production and reserves. Finally, Section V discusses the expansion of the spot and futures markets for crude oil and refined products since the late 1970s, and its effect on the form and size of firm structure.

I. The Market for Crude Oil

Crude oil demand derives from the demand for refined products. Refined petroleum products are used primarily as transportation fuels, for which substitutes are limited. Inelastic refined product demands imply an inelastic demand for crude oil. A hypothetical monopolist controlling all crude oil could no doubt profitably impose at least a small but significant, non-transitory price increase, easily satisfying the Merger Guidelines criterion for delineating a relevant antitrust market.[1] The relevant market for assessing the effects of mergers on crude oil competition is thus no broader than crude oil.

Crude oils from different fields typically have different chemical characteristics and are most importantly distinguished by density and sulphur content. These differences render economic substitution between crude oil types imperfect. Heavy and sour (high sulphur) crude oils generally sell at lower prices because, compared to lighter and sweeter crudes, they yield smaller amounts of high value products such as gasoline and jet fuel. Some refineries run most efficiently on certain types of crude oils and have little flexibility in using other crude oils without costly and time-consuming

[1] At some point, of course, a sufficiently large and sustained increase in the price of crude oil would significantly depress demand. The 150% increase in world crude oil prices from about $14 per barrel in 1979 to as much as $35 per barrel by the early 1980s was sufficiently large and sustained to depress significantly the demand for crude oil through energy conservation and fuel switching in non-transportation uses. *See* EIA, *Petroleum Chronology of Events: 1970-2000*, *available at* http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/chronology/petroleumchronology2000.htm. Definition of relevant markets for antitrust purposes is premised on price increases that may be much smaller: although the standard benchmark is an increase of 5%, in petroleum matters an increase of 1 cent per gallon (42 cents per barrel) is typically used. *See* Chapter 2, *supra*, at II.B.1.

upgrades. This can limit the ability of refiners to switch among different types of crudes should their relative prices change.

Limitations on refiners' ability to substitute among types of crude oil may warrant delineating relatively narrow product markets for antitrust analysis of some mergers. In BP/ARCO, for example, the Commission alleged that ANS crude oil was a distinct product market because of limitations on some West Coast refineries' ability to switch crude oil types in response to price changes.[2] No anticompetitive effect, however, was alleged regarding world crude oil prices generally, or crude oil prices paid by refineries elsewhere in the United States that did not rely on ANS crude. BP/ARCO argued that ANS did not constitute a relevant market and that the merging firms would be unable to raise the price of ANS profitably.[3] The case settled before the court decided this issue.

Generally speaking, important facts in identifying a relevant antitrust market for crude oil in a merger include the specific product characteristics and locations of the crudes that the merging parties would control and the willingness of refiners using those crudes to switch to other crude oil types. Refiners' willingness to switch to alternative crudes will depend on the technical flexibility of their refineries and the relative delivered prices and qualities of alternative crude oils.[4] It also may be important to assess whether crude oil producers can price discriminate against refiners. If crude oil producers cannot price discriminate, alternative crudes may have to be included in the relevant market even if only some refiners can substitute to them.

Although the Merger Guidelines' market definition test might under certain circumstances suggest otherwise, two facts suggest that broad relevant antitrust markets, embracing multiple crude oil types produced at widely separated locations, are likely to be appropriate in many merger contexts. First, crude oil is traded throughout the world, with large flows from countries with surplus production (such as OPEC countries) to industrial countries (such as the United States). Although the United State is a large crude oil producer, its imports have increased significantly since 1985. Table 5-1 shows that the share of U.S. refinery runs accounted for by imports of crude oil has more than doubled from 27% in 1985 to 63% in 2003. Second, many refineries in the United States have upgraded their facilities to become more flexible in running different types of crude, allowing increased use of imported

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2 BP/ARCO, Complaint ¶¶ 23-25, 38. In addition to an ANS crude oil market, the FTC alleged a relevant product market for "crude oil used by targeted West Coast refiners" and a product market for "all crude oil used by refiners on the West Coast."

3 *See* Answer of Defendants BP Amoco and Atlantic Richfield Co. ¶¶ 19, 20, 25, *FTC v. BP Amoco*, Case No. 00-00416 SI (N.D. Calif. Mar. 1, 2000). *See also* Jeremy Bulow & Carl Shapiro, *The BP Amoco-ARCO Merger: Alaskan Crude Oil (2000)*, in THE ANTITRUST REVOLUTION: ECONOMICS, COMPETITION, AND POLICY 128 (4th ed.) (John E. Kwoka, Jr. and Lawrence J. White., eds., 2004). (Dr. Shapiro was the economic expert for BP and ARCO.)

4 More generally, the scope of substitution and the resulting breadth of the relevant market will depend on the size and duration of the hypothesized anticompetitive price increase. Everything else equal, the larger and more enduring the presumed price increase, the broader the relevant antitrust market is likely to be.

crude oils.[5] This sophistication increases the geographic scope of crude oil procurement for these refineries. As Table 5-2 shows, imports come to the United States from throughout the world.

Imports into the United States are likely to be increasingly important. EIA projects that imported petroleum (crude oil and refined products) will increase its overall share of petroleum products supplied in the U.S. to about 68% in 2025 (with a range of 65%-70%) from the 2001 level of 55%.[6] Imports of both crude oil and refined products are projected to increase significantly, with net crude oil imports projected to increase from 9.3 MMBD in 2001 to 13.1 MMBD in 2025.[7] This increase results from a flat to slightly declining projected supply of domestic crude oil combined with increasing demand for refined products. EIA also projects that North American petroleum imports from OPEC will decrease from 47% of imports in 2001 to 42% in 2025; North American imports from OPEC countries in the Persian Gulf are projected to decline from 22% of imports in 2001 to 20% in 2025.[8]

A second fact supporting broad relevant markets is that the price relationship among different types of crudes is often highly correlated. If prices of different crudes move closely together, this may indicate that the price of one crude oil cannot get far out of line with the prices of the other crudes without causing refiners to substitute among crudes.[9] Figure 5-1 plots the prices of some leading crudes in the world over the period from 1997 to early 2003. This figure shows that the prices of these major world crudes tracked each other closely. Economic studies also have shown that prices of world crude oils have a close, statistically significant relationship to each other.[10]

II. World Concentration in Crude Oil Production and Reserves

This section provides concentration estimates based on the broadest possible market definition – all crude oils produced worldwide. Concentration in crude oil can be measured by either production or reserves. Shares based on current production indicate market concentration in the short run but do not necessarily

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5 *See* Chapter 7 for discussion of the increasing flexibility of U.S. refineries.

6 EIA, *Annual Energy Outlook 2003*, 83. The import share is projected to be 65% in the "high oil price" case and 70% in the "low oil price" case.

7 *Id.*

8 EIA, *International Energy Outlook 2003*, 42, Table 14. U.S. consumption will continue to account for 82-83% of North American consumption over the period. *Id.* at 185, Table A-4.

9 Nevertheless, price analysis is not definitive in market definition. For example, prices of products in different markets can be highly correlated if a common input accounts for a significant percent of the costs of both products. In that case, the price correlation would be caused by common cost changes for both products rather than by consumer substitution. It is also possible that two products in a Merger Guidelines market would not have closely correlated prices. This may be true if the two products are not close substitutes at current prices, but a 5-10% price increase in one product would cause significant substitution to the other.

10 A.E. Rodriguez & Mark D. Williams, Is the World Oil Market "One Great Pool": A Test, 5 ENERGY STUDIES REVIEW 121 (1993). *See also* John Hayes, Carl Shapiro & Robert Town, Market Definition in Crude Oil: Estimating the Effects of the BP/ARCO Merger, submission to Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products II* (May 8-9, 2002). These papers cite several other studies with similar results.

reflect firms' abilities to maintain market shares in the future at present prices or to expand output in response to higher prices. While more difficult to measure than production, reserves are a better long-run indicator of market concentration. There are several classifications of reserves, depending on the certainty of profitably extracting the oil, with "proved reserves" being the most conservative and certain estimate of economically significant reserves.[11]

World concentration in crude oil and natural gas liquids ("NGL") production is low and has fallen since 1985.[12] Concentration of world crude oil reserves is higher than concentration in production, but is still in the unconcentrated range and has decreased since 1985. Privatization of former state-owned petroleum operations and the breakup of the Soviet Union have been important deconcentrating forces in world production and reserves. Mergers among oil companies have had but a slight impact on world crude oil and NGL concentration measures.

Many countries have at least partially privatized their petroleum industries in the past 20 years. The results of privatization have been especially notable since 1990.[13] The largest oil producing nations that have recently privatized their oil industries are Russia, Norway, Brazil, and, to a more limited extent, China.[14] Other countries

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[11] C.D. Masters, D.H. Root & R.M.Turner, U.S. Geological Survey, Department of the Interior, *World Conventional Crude Oil and Natural Gas: Identified Reserves, Undiscovered Resources and Futures* (1998), *available at* http://pubs.usgs.gov/of/1998/of98-468/text.htm.

"Proved reserves" are the quantity of oil recoverable from known deposits under current economic and operating conditions. This is the most commonly used definition of reserves in the United States and Canada. Proved reserves, though conservative, remain only estimates and are not purely objective measures. Standards for measuring reserves vary widely internationally. For example, the broader definition of "reported reserves" used in many countries refers to the amount of technically recoverable oil based on standard recovery factors or preliminary well tests; this broad definition includes both developed and undeveloped reserves, without consideration of the commercial feasibility of recovery.

Even within the definition of proved reserves, new technical or economic information can lead to significant revisions. As noted in Chapter 3, Shell recently revised its estimates of its proved reserves downward by 20% on the basis of new internal studies. Consider also the treatment of Canadian oil sand resources. Oil sands traditionally have not been thought of as economic, since oil from these deposits is more costly to extract and requires additional upgrading compared to oil from reservoirs. However, crude oil production from oil sands has been increasing in Canada with reductions in development and production costs. In December 2002, the *Oil and Gas Journal* began including Alberta oil sands as proved reserves. This characterization results in a huge increase in Canadian proved reserves from about 5 billion barrels to about 180 billion barrels in 2002. Prior to this change, Canada did not even rank among the top 20 countries with the most proved reserves; after including oil sand reserves as proved, Canada would rank second in reserves behind only Saudi Arabia, whose reserves in 2003 were about 259 billion barrels. According to the EIA, some analysts have cautioned whether it is appropriate or accurate to include Canadian oil sands in proved reserves. EIA, *Country Analysis Briefs - Canada* (Jan. 2004). *See also* EIA, *International Energy Outlook 2003*, 40. However, Tables 5-5, 5-6, 5-7 and 5-9, *infra*, reflect *Oil and Gas Journal's* identification of Canadian oil sands as proved reserves.

[12] NGLs are produced jointly with crude oil as well as with natural gas. As a result, reported statistics generally show the total of crude oil and NGL production.

[13] *See* generally EIA, *Privatization and the Globalization of Energy Markets* (1996).

[14] These countries typically sold part of their national oil company to outside investors and retained partial ownership. The retained ownership varies significantly, with China retaining 90% of its largest oil company (PetroChina) and 57% of Sinopec, while Russia has no remaining interest in several of its privatized companies and only an 8% interest in its largest producer (Lukoil). *See also* Table 5-3, *infra*.

that have privatized their petroleum industries since 1985 include the United Kingdom, France, Spain, Italy, and Argentina.[15] These countries have sold all or part of their former national oil companies to investors, and shares of those companies are publicly traded. A country privatizing its petroleum industry usually also opens that industry at least partially to investment by outside firms.[16] In many cases, foreign companies compete directly against the newly privatized national petroleum company, while in other instances foreign firms enter into joint production ventures with the national petroleum company.[17]

The recently privatized oil companies often have significant activities outside the home country. For example, Lukoil, Russia's largest private oil company, operates in 25 countries, including the United States. Statoil, Norway's largest privatized oil company, operates in 25 countries. ENI, which was privatized in 1995 by the Italian government, operates in 70 countries.[18] Many state controlled companies also have significant business outside their home country.[19]

The breakup of the former Soviet Union also has had a significant impact on concentration in world production. During the 1970s and 1980s, the Soviet Union was the world's leading producer, with 20% of world production in 1985. To the extent that production and reserves should continue to be attributed to national control, the production and reserves in the old Soviet Union are now controlled by multiple successor states, including Russia, Kazakhstan, Azerbaijan, Turkmenistan and Uzbekistan. Declines in output since the late 1980s, due in part to the region's economic and political problems, also reduced the world's percentage of oil produced within the borders of the old Soviet Union. In addition, privatization has fragmented Russian production

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15 EIA, *Privatization and the Globalization of Energy Markets* 9-15 (1996).

16 For example, there has been significant investment by outside companies in Russia. Several companies including Shell, ExxonMobil and ChevronTexaco are considering investing $45 billion in the Sakhalin area of Russia. Benjamin Fulford, *Energy's Eastern Front*, FORBES, 60 (Dec. 24, 2001). Also, BP agreed to pay $6.75 billion for 50% of Tyumen Oil, Russia's fourth largest producer. *See Not Beyond Petroleum*, THE ECONOMIST (Feb. 15, 2003).

17 Some countries that have maintained full ownership over their national oil company have opened their domestic crude oil production to outside companies. Venezuela has done this through both production sharing agreements and joint ventures with foreign oil companies. EIA, *Performance Profiles of Major Energy Producers 2001*, 69-70.

18 Lukoil Oil Company, *General Information*, *available at* http://www.lukoil.com/static_6_5id_29_.html; Statoil, *Statoil in Brief*, *available at* http://www.statoil.com/STATOILCOM/SVG00990.NSF?opendatabase&lang=en&artid=3FED33ECC77666314125665D004E05E3; ENI S.p.A., *ENI's Way*, *available at* http://www.eni.it/eniit/eni/internal.do?mnselected=lc_1_eni_s_way&channelId=-1073751856&menu=false&mncommand=openById&mnparam=lc_1_eni_s_way&BV_UseBVCookie=Yes&lang=en.

19 For example, PetroChina holds oil concessions in Kazakhstan, Venezuela, Sudan, Iraq, Iran, Peru, and Azerbaijan. Petronas, the state oil company of Malaysia, has exploration and production projects in Syria, Turkmenistan, Iran, Pakistan, China, Vietnam, Burma, Algeria, Libya, Tunisia, Sudan, and Angola. EIA reports that overseas operations now make up nearly one-third of Petronas's revenue. EIA, *Country Analysis Briefs - China* (June 2002); EIA, *Country Analysis Briefs - Malaysia* (Nov. 2003).

among numerous private petroleum companies.[20]

Privatization is important, because it has made the relevant competitive entities for market share calculations less well-identified with individual countries. The 1989 Merger Report assessed concentration using country data for production and reserves, except for the United States and Canada, where shares were assigned to individual companies based on their holdings in those two countries. With the extensive privatization since 1990, many state-controlled entities have been succeeded by privatized companies that do not necessarily limit crude oil activities to their home countries, but increasingly operate across national borders. Thus, production and reserves data measured by country are increasingly unrelated to the production and reserves of the petroleum companies – the relevant competitors in the sale of crude oil.[22]

On the other hand, national governments may still have some control over the output of private firms operating within their territory, exercised through policy instruments such as export tariffs and quotas, or through more direct involvement such as setting terms under production sharing contracts. For example, Russia and other non-OPEC producers (such as Norway and Mexico) sometimes have pledged to reduce production in conjunction with OPEC output reductions. These attempts to exercise control over private firms are not always successful, however. In one such instance, in November 2001, OPEC agreed to reduce its output only if five non-OPEC members (including Russia, Mexico and Norway) also agreed to reduce production.[23] The Russian government attempted to limit the country's oil exports in line with OPEC's request. However, EIA notes that the privatized Russian oil companies did not comply; Russian oil exports increased over the first half of 2002.[24]

If governments can control output within their borders, countries are the relevant competitive entities. This issue is complex, however, and the evidence is mixed as to whether such control is significant; in the following section concentration is estimated two ways. First, all companies, whether state-owned or private, are assumed to be independent competitors for purposes of market share calculation. Second, consistent with the approach of previous Merger Reports, countries are assumed

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[20] EIA, *Privatization and the Globalization of Energy Markets* 21-22 (1996). The top 10 Russian crude oil producers are listed in Table 5-3, *infra*.

Many of the other successor states have partially privatized their oil industries. For example, Kazakhstan, the largest producer of the successor states, which has a state owned company, Kazmunaigaz (formerly Kazakhoil), has allowed more foreign investment. Uzbekistan announced in May 2000 that it intends to sell 49% of the shares in Uzbekneftegaz, the state oil company, to foreign investors, but has failed thus far to secure a major collaboration with foreign investors. EIA, *Country Analysis Briefs - Kazakhstan* (July 2003); EIA, *Country Analysis Briefs - Uzbekistan* (May 2002); EIA, *Country Analysis Briefs - Caspian Sea Region* (Aug. 2003).

[22] In some cases a national oil company still completely controls its country's crude oil supplies, while controlling little outside the country, making the country in effect a competitor – *e.g.*, Saudi Arabia (Aramco), Iran, or Mexico (Pemex).

[23] EIA, *Country Analysis Briefs - OPEC* (Dec. 2001).

[24] EIA, *Country Analysis Briefs - Russia* (Nov. 2002).

to be the relevant competitive entities, with the exception of the United States and Canada, where holdings are attributed to individual companies. These alternatives are referred to as the "company approach" and the "country approach," respectively, and should be interpreted as lower and upper bound estimates of the true level of concentration in world crude oil and NGLs.

The concentration of world crude oil and NGL production based on the company approach is reported for 1990-2002 in Table 5-3. According to this measure, concentration of world production fell from an HHI of 527 in 1990 to 276 in 2002. Table 5-3 also shows that the share of world crude oil production accounted for by major U.S.-based companies declined from 11.5% in 1990 to 8.3% in 2002.

Table 5-4 shows concentration based on the country approach. By this measure, world production concentration decreased from an HHI level of 610 in 1985 to 417 in 2002. Table 5-5 summarizes concentration estimates from the previous FTC reports based on the country approach. It shows that world crude oil production concentration in 2002 was lower than in the 1970s and 1980s. The most important reason for this fall in concentration is the breakup of the Soviet Union.

Concentration is higher in world crude oil reserves, but is still in the unconcentrated range. Table 5-6 shows, under the company approach, that the HHI for world crude oil reserves was 769 in 2002, significantly lower than in 1990 and 1995. Under the country approach shown in Table 5-7, the HHI for world crude oil reserves was 812 in 2002, down from levels for 1995 and 1990. Table 5-5 shows the concentration of world crude oil reserves based on the country approach for earlier years. Generally, since the mid-1970s the HHI for world concentration in reserves has fluctuated around 1,100. However, concentration fell significantly in 2002 due to the apparent emergence of the Canadian oil sands as proved reserves. Concentration is higher than in production because large oil producing countries (Saudi Arabia and other OPEC states) have larger shares of reserves than of current production.

Recent large mergers among major oil companies have had very little impact on concentration in world production and reserves. The 1998 merger of BP and Amoco combined firms with worldwide production shares in 1997 of 1.7% and 0.9%, respectively, and increased the HHI from 314 to 317. The combined firm's share of worldwide production in 2002, reflecting also the subsequent acquisition of ARCO in 2000 (and the divestiture of ARCO's ANS assets to Phillips), was 2.7%. Exxon and Mobil, which merged in 1999, had worldwide shares of crude oil production in 1998 of 2.1% and 1.3%, respectively. Their merger increased the HHI from 288 to 293.[25] The combined firm's share of world production in 2002 was 3.3%. Chevron and Texaco, which merged in early 2001, had world production shares of 1.5% and 1.1%, respectively, in 2000. Their merger increased the HHI from 290 to 293. Finally, the merger of Phillips and Conoco in 2002 combined firms whose shares of world production

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[25] The market shares and HHIs for 1997 and 1998 are not reported in Table 5-3, but are based on the same sources.

in 2000 were 0.8% and 0.6%, respectively. The cumulative increase in the *pro-forma* HHIs due to the above mergers was about 14.[26] The *actual* HHI fell from 305 in 1995 to 276 in 2002, despite these mergers, because of other changes in the market.

The effect of these mergers on concentration of world reserves has been even smaller. The BP/Amoco merger combined firms with shares of worldwide reserves of 0.7% and 0.2%, respectively, and left the HHI unchanged at 1,095. The combined firm's share of worldwide reserves, reflecting also the subsequent acquisition of ARCO in 2000 (and the divestiture of ARCO's ANS assets to Phillips), was 0.8% in 2002. Exxon and Mobil had worldwide shares of crude oil reserves in 1998 of 0.7% and 0.5%, respectively, and their merger left the HHI roughly unchanged at 1,039. Chevron and Texaco had world reserve shares in 2000 of 0.5% and 0.3%, respectively, while in 2000 Phillips and Conoco had respective shares of world reserves of 0.3% (which includes Phillips's acquisitions of ARCO's ANS assets) and 0.2%. Each of the above mergers increased the HHI by less than 1 point.

26 The change in the HHI caused by a merger is twice the product of the merging firms' market shares. Thus, the Exxon/Mobil merger increased the HHI by 5 to 6 points. The merger of BP with Amoco and ARCO (and the divestiture of ARCO's ANS crude oil assets) caused an increase of about 5 HHI points. The acquisition of Amoco increased the HHI by 3 points and the net acquisition of about 0.4% of world crude oil production from ARCO (with about 0.5% going to Phillips) increased the HHI an additional 2 points. Based on 2000 data, Chevron's acquisition of Texaco increased the HHI 3 points, and Phillips's acquisition of Conoco increased the HHI by 1 point.

III. OPEC Control of World Production and Reserves

OPEC's ability to affect world crude oil prices became apparent during the early 1970s. Although coordination among member states is imperfect, with cheating on stated output restrictions a common occurrence,[27] it is clear that OPEC has continued to exercise a significant degree of market power in crude oil. In March 2000, OPEC indicated it would target a price band of $22 to $28 per barrel, with a mechanism to increase production if price exceeds that range and to decrease production if price falls below.[28] OPEC's announced production cuts of late 2001 had the effect of raising world prices beginning in March 2002. In September 2003, OPEC lowered its production targets from 25.4 MMBD to 24.5 MMBD, effective November 1, 2003.[29] OPEC decided in February 2004 to reduce further its target to 23.5 MMBD, effective April 1, 2004. By December 2003, the price of crude oil exceeded the $28 upper boundary and remained well above that level through July 2004, trading as high as the low $40 per barrel range.[30] Most OPEC members, however, have not strictly adhered to recent pledges to restrict output in line with production targets. For example, in March 2004 total production of the

27 EIA, *Country Analysis Briefs - OPEC* (Oct. 2002). For example, OPEC's official quota was 21.7 million barrels per day in 2002, but members produced more than 10% above this quota level in September 2002.

28 *Id*.

29 EIA, *Country Analysis Briefs - OPEC* (Apr. 2004).

30 *See* EIA, *Weekly Petroleum Status Report*, various weeks.

OPEC countries (excluding Iraq) was 25.81MMBD, which exceeded the November 2003 target by 1.31MMBD.[31]

It is important to recognize that crude oil production has grown in non-OPEC areas since the time of the 1982 Merger Report. As Table 5-8 shows, non-OPEC countries' share of world production increased significantly at OPEC's expense from 1974 to the collapse of high oil prices in the mid-1980s. Although OPEC's share of world production has recovered somewhat since the mid-1980s, crude oil production in non-OPEC areas has continued to expand. The North Sea area and Mexico became major producers during the 1980s, while much of the new non-OPEC supply during the 1990s came from Latin America, West Africa, the non-OPEC Middle East, and China. Pacific Rim nations and Australia also may emerge as important producers in the years to come.[32]

Saudi Arabia is the most important producer in OPEC, having about 11.6% of world production and about 21.6% of world reserves in 2002.[33] Saudi Arabia also holds much of the world's excess crude oil production capacity.[34] Observers have argued that Saudi Arabia's production share appears large enough for it to be able to affect world prices unilaterally.[35] Saudi Arabia's position as a very low-cost producer reportedly enables it to exert some pressure on other producers to cooperate in output restrictions via credible threats of driving down world prices with unilateral output increases.[36] Nonetheless, Saudi Arabia's market share is well below levels normally associated with unilateral market power. While its decision to increase or decrease national output may well have noticeable effects on world prices as long as other suppliers do not offset them, Saudi Arabia's success in influencing world prices in the longer term may be based more on an ability to cajole other producers to behave cooperatively.[37]

Production levels of individual OPEC members and OPEC's overall share of world production for selected years since 1974 are shown in Table 5-8. OPEC's share of world production fell from a peak of 54% in 1974 to 30% in

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[31] International Energy Agency, *Monthly Oil Market Report* 13-14 (Apr. 9, 2004), *available at* http://omrpublic.iea.org/omrarchive/09apr04full.pdf.

[32] EIA, *International Energy Outlook 2003*, 38-39. As footnote 11, *supra*, suggests, Canada also may emerge as a first-tier crude oil producer if its oil sands deposits are indeed economic.

[33] Saudi Arabia's share of world crude oil production peaked in 1974 at 14.7%, declined to a low of 6.5% in 1985 and then increased to 13.0% in 1995 before subsiding to 12.1% in 2000. Saudi Arabia's share of world reserves increased from 22.4% in 1973 to 25.4% in 2001, with its share never outside the 22.4% to 26.0% range.

[34] EIA indicates that Saudi Arabia holds about half of OPEC's excess capacity, and that little excess capacity exists in non-OPEC countries. EIA, *Country Analysis Briefs - OPEC* (Feb. 2003); EIA, *Country Analysis Briefs - Non-OPEC Fact Sheet* (June 2002).

[35] *See, e.g.,*, W. David Montgomery, Crude Oil Supply and Pricing Issues, submission to Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products II* (May 8-9, 2002).

[36] Phillip K. Verleger, World Oil Markets: Changing Structure and Greater Price Volatility Causing the Third Petro-Recession, submission to Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products I* (Aug. 2, 2001).

[37] *Regime Change for OPEC?*, THE ECONOMIST (Apr. 26, 2003).

1985, with a subsequent gradual increase to about 40% since 2000. Table 5-9 shows that OPEC's share of world crude oil reserves increased from 67% in 1973 to 79% in 2000, but then declined to the 1973 level in 2002, a change largely attributable to the inclusion of Canadian oil sands as proved reserves. While the ability of non-OPEC producers to raise production is a constraint on OPEC's pricing power, that constraint may be limited because some non-OPEC producers at times coordinate output with OPEC. In particular, EIA reports that Mexico has made seven pledges to restrict exports in conjunction with OPEC since 1997. Other non-OPEC countries that have sometimes made commitments to reduce output or exports include Russia, Norway, Oman, and Angola.[38]

To the extent that OPEC members make output restrictions jointly, the world concentration measures provided above understate the true level of market concentration. Aggregating its members' production and reserves and assigning them to OPEC as a single entity yields much higher concentration levels. For example, treating OPEC as a single entity results in a world production HHI of 1,680 and a world reserves HHI of 4,528 in 2002 under the country approach. These higher figures, however, overstate concentration to the extent that coordination among OPEC members is imperfect.

The 1982 and 1989 Merger Reports raised potential anticompetitive scenarios involving the effect of mergers and acquisitions on OPEC's exercise of market power.[39] The 1982 Merger Report stated that if a merger eliminated an aggressive, price-conscious buyer, the transaction might remove a cartel-destabilizing influence. Oil company ties to OPEC countries, whether in the form of investments or important contractual commitments, might temper some companies' zeal to seek lower crude oil prices. Acquisition by such companies of other firms without similar ties, according to the 1982 Merger Report, might result in a combined firm with interests more aligned with those of OPEC. The 1982 Merger Report concluded, however, that it was uncertain whether these anticompetitive effects could be predicted with enough confidence in the context of a particular merger to warrant antitrust enforcement.[40] This cautious assessment remains valid and is consistent with the

[38] EIA, *Country Analysis Briefs - Non-OPEC Fact Sheet* (May 2003).

[39] 1982 Merger Report 137-49; 1989 Merger Report 74.

One commentator at the FTC conference, *Factors That Affect Prices of Refined Petroleum Products II,* argued that there was an indirect relation between OPEC market power and recent oil mergers and acquisitions. Dr. Philip Verleger argued that mergers among major oil companies have resulted in cost-cutting measures, including reductions in the holding of inventory. According to Verleger, inventory reductions have inadvertently aided OPEC and increased price volatility because the price buffering effect of existing stocks on production cuts is weakened. *See* Verleger, *World Oil Markets, supra,* note 36, at 32-33. *See* transcript of discussion of Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products II* 53-56 (May 8, 2002).

[40] 1982 Merger Report 137-49. According to the 1982 Merger Report, other considerations of the theory would need to acknowledge instances of "OPEC-tied" companies engaging in activities detrimental to OPEC's interest and the possibility that a merger between a tied company and a non-tied company might actually strengthen the bargaining position of the merged company vis-a-vis OPEC.

absence of any FTC enforcement action involving petroleum mergers based on this theory of OPEC stabilization.

The 1989 Merger Report raised a variant of the OPEC stabilization theory: acquisitions of major non-OPEC oil companies by OPEC members might enhance OPEC's ability to maintain supracompetitive prices.[41] Though the 1989 Merger Report did not spell out the precise concern, the anticompetitive effect might come from either (1) additional horizontal market power via the acquisition of crude oil production or reserves or (2) the elimination of a particularly disruptive buyer of crude.[42] Although there have been some whole or partial acquisitions of private oil companies or assets by OPEC members since 1985, these are likely to have been too small to have any significance for world crude oil prices. The two most notable acquisitions by OPEC members are: (1) Saudi Aramco's acquisition of a minority equity position in the Motiva joint venture – which in 1997 combined the downstream assets of Shell and Star Enterprises in the eastern United States by means of Aramco's minority ownership in Star (a prior joint venture between Texaco and Saudi Aramco, involving Texaco's Eastern refining and marketing assets);[43] and (2) the 1990 acquisition by Venezuela's state oil company, PDVSA, of full control of Citgo.[44] None of these acquisitions involved crude oil, so they raised no horizontal issues involving crude oil and NGLs. Neither Motiva's nor Citgo's consumption of crude oil accounted for enough of world crude oil production for either of these companies to plausibly be viewed as a disruptive buyer.[45]

IV. Domestic Concentration in Crude Oil

This section updates the earlier Merger Reports' statistics on domestic concentration in crude oil production and reserves. As a general matter, the competitive significance of domestic crude oil concentration has been increasingly limited due to foreign crude oil imports, although control of certain types of domestic crudes may raise antitrust concerns under certain circumstances. Domestic concentration, of course, would be more meaningful as a competitive index should future, unforeseen circumstances sharply limit imports into the United States.

U.S. crude oil production historically has been characterized by many thousands of individual competitors, with nearly all having insignificant reserve or production

41 1989 Merger Report 74.

42 Such transactions also may be partially or wholly motivated by horizontal or vertical efficiencies and are not necessarily anticompetitive.

43 When Texaco was acquired by Chevron in 2001, Texaco's Motiva interests were bought out by Shell and Saudi Aramco, the other two partners, with Shell gaining the majority. Texaco was required by an FTC consent order to divest those assets in order to be allowed to merge with Chevron. In 1997, Shell and Texaco also formed a separate venture, Equilon, which combined their downstream assets in the western United States.

44 PDVSA also has made several other downstream acquisitions in the United States, including: full control of Unocal's Lamont, Illinois refinery and associated marketing assets in 1997; full control of Union Pacific's Corpus Christi refinery in 1988; and partial interests in Lyondell's Houston, Texas refinery, Mobil's Chalmette, Louisiana refinery, and Phillips's Sweeny, Texas refinery.

45 Motiva's U.S. refining capacity in 2000 was 860 MBD, or about 1.1% of world crude oil production. Citgo's U.S. refining capacity in 2000 was 703 MBD, less than 1% of world crude oil production.

shares. The number of domestic producers remains large, but the ranks have thinned. There has been consolidation and exit among so called "independent" producers, which are enterprises ranging widely in size that are either exclusively or very largely confined to upstream operations. The Independent Petroleum Association of America reports that over the last 10 years the number of U.S. independent producers has declined from over 10,000 to about 7,000, while the number of drilling operators has fallen from over 5,000 to 2,000.[46] Some of the consolidation among the independent producers has involved significant transactions, such as Anadarko's acquisition of Union Pacific Resource Group in 2000 for approximately $4.4 billion and Devon's acquisition of Mitchell in 2001 for about $3.5 billion.

Table 5-10 shows that U.S. crude oil and NGL production remains unconcentrated and increased only slightly from 251 in 1981 to 297 in 2002 due to recent mergers. Table 5-11 indicates that the HHI in crude oil reserves in the United States has increased from 322 in 1981 to 366 in 2002. Concentration is within the range classified as "unconcentrated" (by the Merger Guidelines), although it has increased, in part due to recent large mergers.

In conclusion, concentration of domestic crude oil production and reserves remains low. Aside from potential instances when particular refiners might be vulnerable to a price increase if a merger were to consolidate a significant fraction of control over certain types of crude oil, the general competitive significance of domestic concentration in crude oil is very limited due to the constraints represented by imports.

V. Expansion of Spot and Futures Markets for Crude Oil

The expansion of spot and futures markets for crude oil and refined products since the late 1970s is an important development not reflected in production or reserve concentration estimates. The expansion of spot and futures markets has been accompanied by the entry of many independent brokers and traders, who have become important players in the pricing of crude oil and refined products.

The increasing transaction volume in these markets also appears to have reduced the incentives toward vertical integration between upstream and downstream levels. Prior to the development of these markets, refiners without either a captive source of crude oil or long-term contracts at fixed prices were vulnerable to supply shortages that would interfere with efficient refinery utilization. Similarly, refineries optimized for a particular type of crude oil might be vulnerable to the exercise of market power by owners of that type of oil.

More freely traded product has allowed for more certainty and broadened the alternative sources of supply for many refiners. Spot market transactions have become more important in oil trading. A 1993 General Accounting Office ("GAO") report estimated that before 1979 only 1% to

[46] Independent Petroleum Association of America, *Frequently Asked Questions, available at* http://www.ipaa.org/info/faq.

3% of worldwide crude oil was traded on a spot basis; by 1989 this amount had increased to about 33%. The growth of futures markets for crude oil and refined products during the 1980s was similarly dramatic. Futures trading in crude oil was first implemented by the New York Mercantile Exchange ("NYMEX") in 1983, and GAO reported that the average daily volume of crude oil traded on NYMEX futures contracts increased from about 1.7 MMBD in 1983 to about 83 MMBD in 1991.[47] The development of futures markets encourages trading since it provides a way to efficiently transfer the risk inherent in market price volatility among producers, refiners and others. The development of spot and futures markets also has facilitated contract formation between buyers and sellers by allowing future price terms to be negotiated in reference to one of the recognized spot or futures grades rather than contracting at fixed prices. At the same time, this broadening of crude oil trading may also have encouraged refiners to become more flexible in the types of crude oil they can efficiently process.[48]

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47 General Accounting Office, *Energy Security and Policy: Analysis of the Pricing of Crude oil and Petroleum Products* 34-37 (1993). By the early 1990s, the growth of the crude oil futures market had leveled off, although futures markets for gasoline and heating oil continued to grow.

48 The expansion of freely traded crude oil may not benefit all refiners to the same extent. For example, shipping logistics could reduce the number of effective suppliers in some cases, as refiners are limited to contracting for crude oil with firms that can deliver to the refinery. This problem may be less acute for refineries with access to deep water ports, but more acute for inland refineries that must rely on pipeline shipments from nearby crude oil fields.

Figure 5-1
Crude Oil Prices

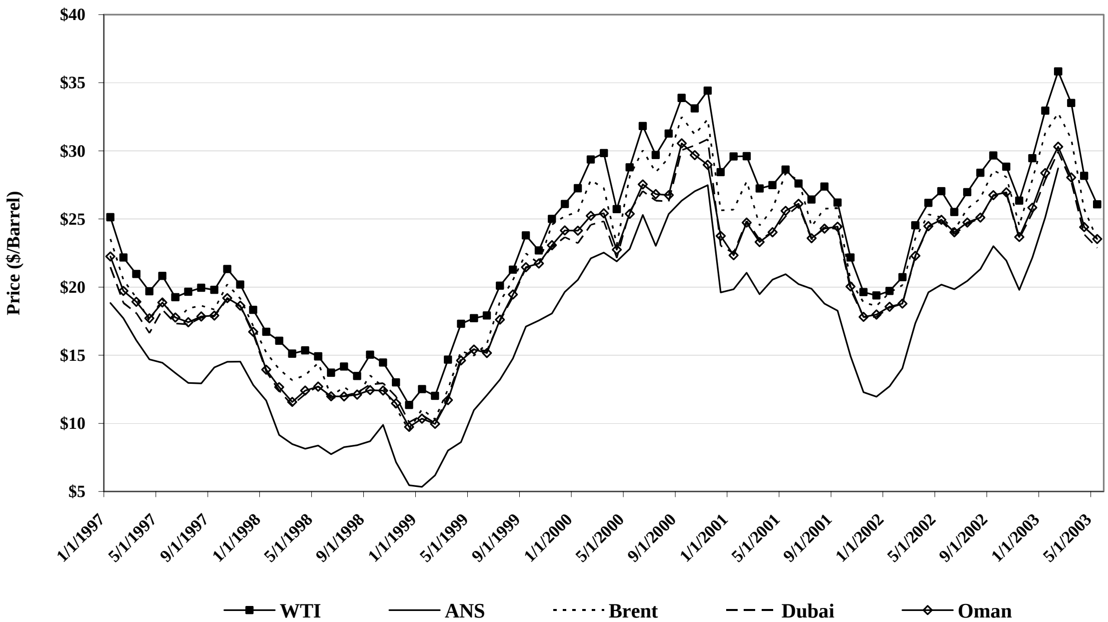

Table 5-1 – U.S. Refinery Runs of Crude Oil by Source
1985-2003
(1000's bbls/day)

Year	Domestic Crude Oil Production	U.S. Crude Oil Imports	U.S. Crude Oil Exports	Refinery Runs of Crude Oil	Imports as % of Refinery Runs
1985	8,971	3,201	204	12,044	27
1990	7,355	5,894	109	13,409	44
1995	6,560	7,230	95	13,973	52
2000	5,822	9,071	50	15,067	60
2001	5,801	9,328	20	15,128	62
2002	5,746	9,140	9	14,947	61
2003	5,681	9,665	12	15,304	63

Source: EIA, *Petroleum Supply Annual*, Table S-2 (2000, 2003).

Table 5-2 – U.S. Crude Oil Imports by Country of Origin 2000-2002 (1000's bbls/year)

	2000		2001		2002	
Country	Imports	% of Total	Imports	% of Total	Imports	% of Total
Saudi Arabia	557,569	16.8	588,075	17.3	554,500	16.6
Canada	493,256	14.9	494,796	14.5	527,304	15.8
Mexico	480,469	14.5	508,715	14.9	547,443	16.4
Venezuela	447,736	13.5	471,243	13.8	438,270	13.1
Nigeria	320,137	9.6	307,173	9	215,122	6.4
Iraq	226,804	6.8	289,998	8.5	167,638	5.0
Colombia	116,311	3.5	94,844	2.8	85,783	2.6
Norway	110,653	3.3	102,724	3	127,136	3.8
Angola	107,820	3.2	117,254	3.4	117,058	3.5
United Kingdom	106,332	3.2	89,142	2.6	147,935	4.4
Kuwait	96,367	2.9	86,535	2.5	78,803	2.4
Other	256,362	7.7	254,395	7.5	329,183	9.9
Total	3,319,816	100.0	3,404,894	100.0	3,336,175	100.0

Source: EIA, *Petroleum Supply Annual*, Table 21 (2000, 2001, 2002).

Table 5-3 – Concentration of World Crude Oil and NGL Production - Company Basis 1990-2002 (Production in Thousand bbl/ day)

Company	Country	State Owned (%)	1990 Produc-tion	1990 Market Share (%)	1995 Produc-tion	1995 Market Share (%)	2000 Produc-tion	2000 Market Share (%)	2002 Produc-tion	2002 Market Share (%)
Saudi Aramco	Saudi Arabia	100	6,279	9.6	8,585	12.5	8,602	11.4	8,013	10.7
NIOC	Iran	100	3,183	4.9	3,720	5.4	3,787	5.0	3,553	4.7
Pemex	Mexico	100	2,974	4.5	2,722	4.0	3,450	4.6	3,529	4.7
PDVSA	Vene-zuela	100	2,135	3.3	2,885	4.2	3,295	4.4	2,900	3.9
Exxon Mobil	U.S.	0	1,712	2.6	1,726	2.5	2,553	3.4	2,496	3.3
Shell	UK/Neth-erlands	0	1,890	2.9	2,254	3.3	2,274	3.0	2,372	3.2
PetroChina [1]	China	90	2,774	4.2	2,796	4.1	2,091	2.8	2,109	2.8
INOC	Iraq	100	2,125	3.2	600	0.9	2,597	3.4	2,040	2.7
BP	UK	0	1,322	2.0	1,213	1.8	1,928	2.6	2,018	2.7
ChevronTexaco	U.S.	0	935	1.4	1,001	1.5	1,159	1.5	1,897	2.5
KPC	Kuwait	100	1,042	1.6	2,070	3.0	1,653	2.2	1,867	2.5
NNPC	Nigeria	100	1,199	1.8	1,200	1.8	1,312	1.7	1,787	2.4
ADNOC	UAE	100	1,128	1.7	1,300	1.9	1,350	1.8	1,690	2.3
Lukoil	Russia	8			1,116	1.6	1,557	2.1	1,545	2.1
Totalfina Elf	France	0	420	0.6	456	0.7	1,433	1.9	1,589	2.1
Petrobras	Brazil	33	653	1.0	716	1.0	1,324	1.8	1,535	2.0
Yukos	Russia	0			722	1.1	986	1.3	1,392	1.9
Surgutneftegas	Russia	0			669	1.0	813	1.1	990	1.3
ConocoPhillips [2]	U.S.	0	372	0.6	237	0.3	597	0.8	986	1.3
Libya NOC	Libya	100	1,041	1.6	1,345	2.0	1,336	1.8	975	1.3
Sonatrach	Algeria	100	1,063	1.6	1,283	1.9	1,336	1.8	971	1.3
ENI	Italy	36	458	0.7	612	0.9	748	1.0	921	1.2
Pertamina	Indonesia	100	761	1.2	1,065	1.6	970	1.3	845	1.1
Tyumen Oil	Russia	0			456	0.7	572	0.8	758	1.0
Sinopec	China	57			*		676	0.9	739	1.0
Statoil	Norway	80	430	0.7	499	0.7	733	1.0	742	1.0
Petronas	Malaysia	100	373	0.6	370	0.5	529	0.7	700	0.9
Qatar Petroleum	Qatar	100	467	0.7	475	0.7	858	1.1	640	0.9
Repsol YPF	Spain	0	154	0.2	*		636	0.8	584	0.8
Ecopetrol	Colombia	100	263	0.4	460	0.7	443	0.6	578	0.8
ONGC	India	95	656	1.0	633	0.9	534	0.7	553	0.7
PDO (Oman)	Oman	60	391	0.6	481	0.7	538	0.7	516	0.7
Sibneft	Russia	0			409	0.6	344	0.5	510	0.7
A.O.Sidanco	Russia	0			459	0.7	259	0.3	380	0.5
EGPC	Egypt	100	571	0.9	446	0.7	398	0.5	378	0.5
Norsk Hydro	Norway	44	92	0.1	*	0.0	326	0.4	370	0.5
Syrian Petrol.	Syria	100			*		300	0.4	341	0.5
Amerada Hess	U.S.	0	175	0.3	260	0.4	261	0.3	325	0.4
Rosneft	Russia	100			257	0.4	269	0.4	322	0.4
Anadarko	U.S.	0	*		*		131	0.2	247	0.3
Marathon	U.S.	0	197	0.3	205	0.3	207	0.3	207	0.3
Gazprom	Russia	38			*		198	0.3	204	0.3

Table 5-3 *(continued)*

Company	Country	State Owned (%)	1990 Produc-tion	1990 Market Share (%)	1995 Produc-tion	1995 Market Share (%)	2000 Produc-tion	2000 Market Share (%)	2002 Produc-tion	2002 Market Share (%)
EnCana	Canada	0	*		*		*		204	0.3
Socar [3]	Azer-baijan	100	*		*		180	0.2	179	0.2
Unocal [4]	U.S.	0	254	0.4	240	0.4	190	0.3	167	0.2
Petroecuador [5]	Ecuador	100	203	0.3	306	0.4	259	0.3	*	
Talisman Energy [6]	Canada	0	*		*		251	0.3	*	
Slavneft	Russia/ Belarus	70/10			258	0.4	245	0.3	*	
BHP [7]	Australia	0	233	0.4	208	0.3	239	0.3	*	
Oryx/Kerr-McGee [8]	U.S.	0	211	0.3	181	0.3	207	0.3	*	
Occidental Petro. [9]	U.S.	0	219	0.3	278	0.4	*		*	
Texaco [10]	U.S.	0	810	1.2	762	1.1	800	1.1		
Conoco [2]	U.S.	0	359	0.5	414	0.6	462	0.6		
Mobil [11]	U.S.	0	779	1.2	810	1.2				
Elf Aquitaine[12]	France		518	0.8	764	1.1				
Amoco [13]	U.S.	0	782	1.2	660	1.0				
Arco [13]	U.S.	0	705	1.1	650	0.9				
YPF [14]	Argentina	0	293	0.4	373	0.5				
Petrofina[12]	Belgium	0	116	0.2	141	0.2				
USSR	USSR	100	11,400	17.4						
	Sum:		54,117	82.6	51,748	75.5	58,196	77.2	57,664	77.0
	World Total:		65,537		68,499		75,424		74,931	

Measure	Concentration 1990	1995	2000	2002
4-Firm (%)	36.4	26.3	25.4	24.0
8-Firm (%)	50.0	39.1	38.0	36.0
HHI	527	305	288	276

Source: Company crude oil and NGL production data: *Petroleum Intelligence Weekly* ("*PIW*"), (Dec. 23, 1991; Dec. 16, 1996; Dec. 17, 2001; Dec. 15, 2003). % of State Ownership is as of date of latest entry. Total World oil and NGL production: EIA, *International Energy Annual*, Table G1, "World Production of Crude Oil, NGPL and Other Liquids 1980-2002 (Thousand Barrels per Day)", (2002). Data from *PIW* are used by permission.

Note:

* Company was not in *PIW* Top 50 or production less than 0.2% of world total.

[1] Total production of China in 1990

[2] Phillips and Conoco merged in 2002.

[3] Socar was not a *PIW* Top 50 firm in 2000. 2000 production: *FSU Energy*, "Caspian/central Asia; miscellaneous brief articles; Statistical Data Included", 6 (Jan. 12, 2001).

[4] Unocal was not a *PIW* Top 50 firm in 2000. 2000 production: Unocal Corp., *Form 10-K* (2000).

[5] Petroecuador was not a *PIW* Top 50 firm in 2001. 2001 production: *Oil Daily*, "Ecuador Sends Army to Protect Pipeline Work" (Feb. 27, 2002); *Oil Daily*, "Ecuador Crude Output Drops" (Aug. 5, 2002).

[6] Talisman Energy was not a *PIW* Top 50 firm in 2000. 2000 production: *Platt's Oilgram News*, "Canada's Talisman to Hike Capex by 5%", 15 (Jan. 15, 2002).

[7] BHP was not a *PIW* Top 50 firm in 2001. 2001 production: BHP Billiton, *Business Wire*, "Quarterly Production Report" (Jan. 24, 2002).

Table 5-3 *(continued)*

[8] Kerr-McGee acquired Oryx in 1999. Oryx was not a *PIW* Top 50 company in 1995, nor was Kerr-McGee in 2000 and 2001. 1995 production: *Platt's Oilgram News*, "Why isn't Oryx Energy getting any respect?", 3 (Mar. 25, 1996); 2000 and 2001 production: Kerr-McGee Corporation, *Form 10-K*, 3 (2001).
[9] Occidental was not a *PIW* Top 50 firm in 1995. 1995 production: *PR Newswire*, "Occidental Says Future Bright as Oil and Gas Production Grows, Chemical Outlook Strengthens" (Apr. 26, 1996).
[10] Texaco and Chevron merged in 2001.
[11] Exxon acquired Mobil in 1999.
[12] Total acquired Petrofina and Elf Aquitaine in 1999.
[13] BP acquired Amoco in 1999 and ARCO in 2000.
[14] YPF was acquired by Repsol in 1999.

Table 5-4 – Concentration of World Crude Oil and NGL Production - Country Basis 1985-2002 (Production in Thousand bbl/day)

Country	1985 Production	1985 Market Share (%)	1990 Production	1990 Market Share (%)	1995 Production	1995 Market Share (%)	2000 Production	2000 Market Share (%)	2002 Production	2002 Market Share (%)
Countries										
Saudi Arabia	3,763	6.5	7,030	10.7	8,977	13.1	9,214	12.2	8,714	11.6
Russia					6,175	9.0	6,711	8.9	7,654	10.2
Mexico	3,016	5.2	2,981	4.5	3,064	4.5	3,450	4.6	3,585	4.8
Iran	2,260	3.9	3,123	4.8	3,703	5.4	3,771	5.0	3,531	4.7
China	2,505	4.3	2,774	4.2	2,990	4.4	3,249	4.3	3,390	4.5
Norway	829	1.4	1,782	2.7	2,905	4.2	3,317	4.4	3,325	4.4
Venezuela	1,740	3.0	2,253	3.4	2,969	4.3	3,440	4.5	2,906	3.9
UK	2,675	4.6	1,928	2.9	2,756	4.0	2,508	3.3	2,503	3.3
UAE	1,353	2.3	2,252	3.4	2,393	3.5	2,568	3.4	2,382	3.2
Nigeria	1,495	2.6	1,810	2.8	1,993	2.9	2,165	2.9	2,118	2.8
Iraq	1,443	2.5	2,070	3.2	585	0.9	2,586	3.4	2,043	2.7
Kuwait	1,077	1.9	1,240	1.9	2,152	3.1	2,194	2.9	2,019	2.7
Brazil	721	1.2	790	1.2	890	1.3	1,530	2.0	1,720	2.3
Algeria	1,157	2.0	1,305	2.0	1,347	2.0	1,484	2.0	1,576	2.1
Indonesia	1,369	2.4	1,539	2.3	1,579	2.3	1,513	2.0	1,347	1.8
Libya	1,085	1.9	1,410	2.2	1,430	2.1	1,470	2.0	1,384	1.8
Kazakhstan					414	0.6	718	0.9	939	1.3
Oman	502	0.9	695	1.1	861	1.3	974	1.3	902	1.2
Angola	231	0.4	475	0.8	646	0.9	746	1.0	896	1.2
Qatar	331	0.6	446	0.7	497	0.7	870	1.2	839	1.1
Argentina	480	0.8	510	0.8	757	1.1	809	1.1	802	1.1
Egypt	913	1.6	914	1.4	980	1.4	850	1.1	756	1.0
Malaysia	450	0.8	631	1.0	714	1.0	763	1.0	785	1.0
India	622	1.1	670	1.0	750	1.1	736	1.0	780	1.0
Australia	640	1.1	638	1.0	614	0.9	793	1.1	708	0.9
Colombia	180	0.3	448	0.7	593	0.9	703	0.9	589	0.8
Syria	178	0.3	390	0.6	584	0.9	528	0.7	516	0.7
Yemen	0	0.0	193	0.3	345	0.5	440	0.6	443	0.6
Ecuador	283	0.5	287	0.4	401	0.6	398	0.5	402	0.5
Gabon	172	0.3	270	0.4	365	0.5	325	0.4	251	0.3
Former USSR	11,935	20.5	11,400	17.4						
Companies for U.S. and Canada[1]										
ExxonMobil	885	1.5	901	1.4	800	1.2	866	1.2	838	1.1
BP	843	1.4	791	1.2	573	0.8	706	0.9	781	1.0
Shell	529	0.9	595	0.9	505	0.7	465	0.6	498	0.7
Chevron	688	1.2	521	0.8	402	0.6	454	0.6	672	0.9
ConocoPhillips	158	0.3	102	0.2	89	0.1	267	0.4	381	0.5
Texaco	702	1.2	458	0.7	381	0.6	491	0.7		
Arco	649	1.1	638	1.0	584	0.9				
Mobil	556	1.0	345	0.5	335	0.5				
Amoco	447	0.8	452	0.7	310	0.5				

Table 5-4 *(continued)*

Company	1,985 Production	1,985 Market Share (%)	1990 Production	1990 Market Share (%)	1995 Production	1995 Market Share (%)	2000 Production	2000 Market Share (%)	2002 Production	2002 Market Share (%)
Sum:	48,863	83.9	57,056	87.1	58,408	85.1	64,061	84.7	62,976	84.0
World Total	58,208		65,537		68,499		75,141		74,931	
		Concentration								
Measure										
4-Firm (%)		36.7		37.4		31.9		30.6		31.3
8-Firm (%)		50.5		51.7		48.9		47.2		47.5
HHI		610		571		435		413		417

Sources: Country output: EIA, *International Energy Annual*, Table G1, "World Production of Crude Oil, NGPL, and Other Liquids, 1980-2002", (2002); Company output: individual firms' *Forms 10-K and 20-F, Annual Reports, Oil & Gas Journal* (for U.S. production), and *Oilweek Magazine (*for Canadian production). BP's 1985 and 1995 Canadian production is estimated using adjoining years' financial filings. Data from the *Oil & Gas Journal* used by permission.

Note:

[1] Production in the U.S. and Canada.
[2] Concentration includes both countries' and companies' shares.

Table 5-5 – Concentration of World Crude Oil and NGL Production and Crude Oil Reserves, Country Basis 1973-2002

Measurement	1973	1978	1981	1984	1985	1990	1995	2000	2002
	Concentration of World Crude Oil and NGL Production (Country Basis)								
4-Firm (%)	45.9	42.9	45.6	39.4	36.7	37.4	31.9	30.6	31.3
8-Firm (%)	60.5	57.2	57.3	52.6	50.5	51.7	48.9	47.2	47.5
HHI	678	693	816	653	610	571	435	413	417
	Concentration of World Crude Oil Reserves (Country Basis)								
4-Firm (%)	56.3	57.4	53.0	53.8	53.5	55.0	54.6	54.7	46.4
8-Firm (%)	72.0	74.0	73.9	74.5	74.7	81.1	80.3	78.5	67.6
HHI	981	1,152	1,047	1,062	1,052	1,156	1,143	1,122	812

Source: Production: 1978-1984: 1989 Merger Report, 81-82, Table 21; 1985-2002: Table 5-5 (*supra*); Reserves: 1978-1984: 1989 Merger Report, 83, Table 22; 1985-2002: Table 5-8 (*infra*).

Table 5-6 – Concentration of World Crude Oil Reserves by Producing Company 1990-2002 (Reserves in Million Barrels At Year End)

			1990		1995		2000		2002	
Company	Country	State Owned (%)	Reserves	Share (%)	Reserves	Share (%)	Reserves	Share (%)	Reserves	Share (%)
Saudi Aramco	Saudi Arabia	100	257,900	25.8	261,450	26.0	261,698	25.4	261,800	21.6
INOC	Iraq	100	100,000	10.0	100,000	9.9	112,500	10.9	112,000	9.2
KPC	Kuwait	100	97,025	9.7	96,500	9.6	96,500	9.4	96,500	8.0
NIOC	Iran	100	92,850	9.3	93,700	9.3	89,700	8.7	99,080	8.2
PDVSA	Venezuela	100	60,054	6.0	66,328	6.6	77,685	7.6	77,900	6.4
ADNOC	UAE	100	64,541	6.5	64,452	6.4	53,790	5.2	55,210	4.6
Libya NOC	Libya	100	20,642	2.1	27,590	2.7	23,600	2.3	36,000	3.0
Pemex	Mexico	100	51,298	5.1	48,796	4.8	28,260	2.7	17,196	1.4
Lukoil	Russia	8			7,300	0.7	14,280	1.4	15,258	1.3
Qatar Petroleum	Qatar	100	4,500	0.5	3,500	0.3	13,200	1.3	15,204	1.3
Gazprom	Russia	38			6,867	0.7	7,215	0.7	15,000	1.2
NNPC	Nigeria	100	11,872	1.2	12,000	1.2	13,500	1.3	14,900	1.2
Yukos	Russia	0			7,300	0.7	11,769	1.1	13,734	1.1
Exxon Mobil	U.S.	0	7,150	0.7	6,670	0.7	12,171	1.2	12,623	1.0
PetroChina [1]	China	90	24,000	2.4	21,000	2.1	11,032	1.1	10,999	0.9
Rosneft	Russia	100			5,840	0.6	4,764	0.5	10,995	0.9
Royal Dutch/Shell	UK/Neth-erlands	0	10,107	1.0	8,846	0.9	9,751	0.9	10,133	0.8
Sonatrach	Algeria	100	9,200	0.9	9,979	1.0	8,740	0.8	9,200	0.8
BP	UK	0	6,730	0.7	6,577	0.7	7,643	0.7	9,165	0.8
Petrobras	Brazil	33	2,800	0.3	6,200	0.6	8,356	0.8	8,955	0.7
Chevron	U.S.	0	3,241	0.3	4,343	0.4	5,001	0.5	8,668	0.7
Tyumen Oil	Russia	0			4,745	0.5	7,459	0.7	8,527	0.7
Totalfina Elf	France	0	2,731	0.3	2,795	0.3	6,960	0.7	7,231	0.6
Surgut-neftegas	Russia	0			4,745	0.5	6,992	0.7	6,642	0.5
Sidanco	Russia	0			6,935	0.7	7,257	0.7	6,577	0.5
Conoco-Phillips [2]	U.S.	0	1,114	0.1	1,091	0.1	3,597	0.3	5,137	0.4
ONGC	India	95	7,997	0.8	5,336	0.5	5,478	0.5	4,380	0.4
Sibneft	Russia	0			2,190	0.2	4,644	0.5	4,720	0.4
Pertamina	Indonesia	100	6,284	0.6	4,259	0.4	4,000	0.4	4,000	0.3
ENI	Italy	36	2,763	0.3	2,402	0.2	3,553	0.3	3,783	0.3
Petronas	Malaysia	100	1,740	0.2	1,845	0.2	2,640	0.3	3,700	0.3
Sinopec	China	57					2,952	0.3	3,320	0.3
PDO	Oman	60	2,580	0.3	3,067	0.3	3,080	0.3	3,158	0.3
Repsol YPF	Spain	0	397	0.0		0.0	2,378	0.2	2,019	0.2
Statoil	Norway	80	2,366	0.2	2,012	0.2	1,994	0.2	1,866	0.2
EGPC	Egypt	100	3,397	0.3	1,950	0.2	1,450	0.1	1,850	0.2
Petro-ecuador [3]	Ecuador	100	1,003	0.1	3,340	0.3	3,402	0.3	*	
Slavneft	Russia/ Belarus	70/10			1,095	0.1	2,816	0.3	*	

Table 5-6 *(continued)*

			1990		1995		2000		2002	
Company	Country	State Owned (%)	Reserves	Share (%)	Reserves	Share (%)	Reserves	Share (%)	Reserves	Share (%)
Texaco [4]	U.S.	0	2,753	0.3	2,658	0.3	3,518	0.3		
Mobil [5]	U.S.	0	3,211	0.3	3,419	0.3				
Arco [6]	U.S.	0	2,930	0.3	2,369	0.2				
Amoco [6]	U.S.	0	2,660	0.3	2,322	0.2				
Elf Aquitaine [7]	France	0	2,002	0.2	2,262	0.2				
USSR	USSR	100	57,000	5.7						
	Sum:		950,838	95.2	926,075	91.9	945,325	91.9	977,430	80.2
	World Reserves:		999,113		1,007,475		1,028,458		1,212,881	
						Concentration				
Measure										
4-Firm (%)				54.8		54.8		54.5		46.9
8-Firm (%)				78.1		75.3		72.3		62.3
HHI				1,100		1,079		1,045		769

Source: Company reserves: *Petroleum Intelligence Weekly* ("*PIW*") (Dec. 23, 1991; Dec. 16, 1996; Dec. 17, 2001; Dec. 15, 2003); World Reserves: *Oil & Gas Journal* (Dec. 31, 1990; Dec. 25, 1995; Dec. 20, 1999; Dec. 18, 2000; Dec. 23, 2002); 1990 data for China and USSR: *Oil & Gas Journal* (Dec. 31, 1990). Data are for end of the referenced year/start of the subsequent year. Data from *PIW* and *Oil & Gas Journal* are used by permission.

Note:

[1] 1990 reserves are for China as a whole.

[2] Phillips and Conoco merged in 2002.

[3] Petroecuador was not included in the 2001 *PIW Top 50*. 2001 estimate: *Oil Daily*, "Ecuador Readies for Ninth Oil Licensing Round, to Be Held in October" (Jul. 11, 2002).

[4] Acquired by Chevron in 2001.

[5] Exxon acquired Mobil in 1999.

[6] BP acquired Amoco in 1998 and ARCO in 2000.

[7] Both Petrofina and Elf Aquitaine were acquired by Total in 1999. Elf Aquitaine was 56% government owned in 1990.

Table 5-7 – Concentration of World Crude Oil Reserves Country Basis 1985-2002 (Billions of Barrels, December 31)

	1985		1990		1995		2000		2002	
Country	Reserves	Market Share (%)	Reserves	Market Share (%)	Reserves	Market Share (%)	Reserves	Market Share (%)	Reserves	Market Share (%)
Saudi Arabia[1]	171,490	24.5	260,000	26.0	261,203	25.9	261,700	25.4	261,800	21.6
Iraq	44,110	6.3	100,000	10.0	100,000	9.9	112,500	10.9	112,500	9.3
Kuwait[1]	92,464	13.2	97,025	9.7	96,500	9.6	96,500	9.4	96,500	8.0
Abu Dhabi	31,000	4.4	92,200	9.2	92,200	9.2	92,200	9.0	92,200	7.6
Iran	47,876	6.8	92,850	9.3	88,200	8.8	89,700	8.7	89,700	7.4
Venezuela	25,591	3.7	59,040	5.9	64,477	6.4	76,862	7.5	77,800	6.4
Russia							48,573	4.7	60,000	4.9
Libya	21,300	3.0	22,800	2.3	29,500	2.9	29,500	2.9	29,500	2.4
Nigeria	16,600	2.4	17,100	1.7	20,828	2.1	22,500	2.2	24,000	2.0
China	18,420	2.6	24,000	2.4	24,000	2.4	24,000	2.3	18,250	1.5
Qatar	3,300	0.5	4,500	0.5	3,700	0.4	13,157	1.3	15,207	1.3
Mexico	49,300	7.0	51,983	5.2	49,775	4.9	28,260	2.7	12,622	1.0
Norway	10,900	1.6	7,609	0.8	8,422	0.8	9,447	0.9	10,265	0.8
Algeria	8,820	1.3	9,200	0.9	9,200	0.9	9,200	0.9	9,200	0.8
Brazil	2,070	0.3	2,840	0.3	4,200	0.4	8,100	0.8	8,322	0.7
Oman	4,000	0.6	4,300	0.4	5,138	0.5	5,506	0.5	5,506	0.5
Kazakhstan							5,417	0.5	9,000	0.7
Angola	2,000	0.3	2,074	0.2	5,412	0.5	5,412	0.5	5,412	0.4
Indonesia	8,500	1.2	11,050	1.1	5,167	0.5	4,980	0.5	5,000	0.4
United Kingdom	13,000	1.9	3,825	0.4	4,293	0.4	5,003	0.5	4,715	0.4
India	3,736	0.5	7,997	0.8	5,814	0.6	4,728	0.5	5,367	0.4
Yemen			4,000	0.4	4,000	0.4	4,000	0.4	4,000	0.3
Dubai	1,400	0.2	4,000	0.4	4,300	0.4	4,000	0.4	4,000	0.3
Malaysia	3,100	0.4	2,900	0.3	4,300	0.4	3,900	0.4	3,000	0.2
Egypt	3,850	0.5	4,500	0.5	3,879	0.4	2,948	0.3	3,700	0.3
USSR/ FSU	61,000	8.7	57,000	5.7	57,000	5.7				
Exxon[2]	3,789	0.5	3,584	0.4	3,458	0.3	4,319	0.4	4,194	0.3
Sum:	476,126		686,378		693,764		710,711		709,960	
World Reserves:	700,141		999,113		1,007,475		1,028,458		1,212,881	

	Concentration				
Measure	1985	1990	1995	2000	2002
4-Firm (%)	53.5	55.0	54.6	54.7	46.4
8-Firm (%)	74.7	81.1	80.3	78.5	67.6
HHI	1,052	1,156	1,143	1,122	812

Source: *Oil & Gas Journal* (Dec. 30, 1985; Dec. 31, 1990; Dec. 25, 1995; Dec. 18, 2000; Dec. 23, 2002). Exxon's U.S. and Canadian crude oil reserves: Exxon Corp., *Form 10-K* (annual) and *Annual Report*. Data from *Oil & Gas Journal* used by permission.

Note:

[1] Reserves for Saudi Arabia and Kuwait each includes one-half of the Neutral Zone reserves.

[2] Reserves in the U.S. and Canada.

Table 5-8 – OPEC Share of World Crude Oil and NGL Production 1974-2002 (Thousand bbl/day)

Country	1974	1980	1985	1990	1995	2000	2002
Saudi Arabia [1]	8,610	10,269	3,763	7,030	8,977	9,214	8,714
Iran	6,067	1,671	2,260	3,123	3,703	3,771	3,531
Venezuela	3,060	2,228	1,740	2,253	2,969	3,440	2,906
Kuwait [1]	2,596	1,751	1,077	1,240	2,152	2,194	2,019
Nigeria	2,255	2,055	1,495	1,810	1,993	2,165	2,118
Iraq	1,971	2,522	1,443	2,070	585	2,586	2,043
Libya	1,541	1,827	1,085	1,410	1,430	1,470	1,384
Indonesia	1,375	1,647	1,369	1,539	1,579	1,513	1,347
Algeria	1,059	1,142	1,157	1,305	1,347	1,484	1,576
Qatar	523	482	331	446	497	870	839
U.A.E. [2]	2,032	1,744	1,353	2,252	2,393	2,568	2,382
Gabon [3]	202	175	172	270			
Ecudor [4]	177	206	283	287			
OPEC	31,468	27,719	17,528	25,035	27,624	31,275	28,859
NON-OPEC	27,264	35,414	40,680	40,502	40,875	44,149	46,072
WORLD	58,732	63,133	58,208	65,537	68,499	75,424	74,931
OPEC Share (%)	53.6	43.9	30.1	38.2	40.3	41.5	38.5

Source: 1980-2002: EIA, *International Energy Annual*, Table G1, "World Production of Crude Oil, NGPL, and Other Liquids, 1980-2002 (Thousand Barrels per Day)" (2002). 1974: 1989 Merger Report 81-82, Table 21.

Note:

[1] Production for Saudi Arabia and Kuwait each includes one-half of the Neutral Zone production.

[2] United Arab Emirates, total of individual emirates' production.

[3] Gabon withdrew from OPEC in January 1995. It is not listed for the 1995 OPEC total because the production data is for full year.

[4] Ecuador withdrew from OPEC in December 1992.

Table 5-9 – OPEC Share of World Crude Oil Reserves 1973-2002 (Billions of Barrels, December 31) [1]

Country	1973	1978	1981	1985	1990	1995	2000	2002
Saudi Arabia [1]	140.8	168.9	167.9	171.5	260.0	261.2	261.7	261.8
Iraq	31.5	32.1	29.7	44.1	100.0	100.0	112.5	112.5
Kuwait [1]	72.8	69.4	67.7	92.5	97.0	96.5	96.5	96.5
Abu Dhabi [2]	21.5	30.0	30.6	31.0	92.2	92.2	92.2	92.2
Iran	60.0	59.0	57.0	47.9	92.9	88.2	89.7	89.7
Venezuela	14.0	18.0	20.3	25.6	59.0	64.5	76.9	77.8
Libya	25.5	24.3	22.6	21.3	22.8	29.5	29.5	29.5
Nigeria	20.0	18.2	16.5	16.6	17.1	20.8	22.5	24.0
Qatar	6.5	4.0	3.4	3.3	4.5	3.7	13.2	15.2
Algeria	7.6	6.3	8.1	8.8	9.2	9.2	9.2	9.2
Indonesia	10.5	10.2	9.8	8.5	11.1	5.2	5.0	5.0
Dubai [2]	2.5	1.3	1.3	1.4	4.0	4.3	4.0	4.0
Sharjah [3]	1.5	0.0	0.3	0.5	1.5	1.5	1.5	1.5
Ras al-Khaimah [2]	0.0	0.0	0.0	0.1	0.4	0.1	0.1	0.1
Gabon [3]	1.5	2.0	0.5	0.5	0.7	n/a	n/a	n/a
Ecuador [4]	5.7	1.2	0.9	1.7	1.4	n/a	n/a	n/a
TOTAL OPEC	421.9	444.9	436.6	475.2	773.8	776.9	814.4	819.0
TOTAL NON-OPEC	206.0	196.7	234.1	224.9	225.3	230.6	214.1	393.9
TOTAL WORLD	627.9	641.6	670.7	700.1	999.1	1,007.5	1,028.5	1,212.9
OPEC Share (%)	67.2	69.3	65.1	67.9	77.5	77.1	79.2	67.5

Sources: 1985-2002: *Oil & Gas Journal* (Dec. 30, 1985; Dec. 31, 1990; Dec. 25, 1995; Dec. 18, 2000; Dec. 23, 2002); 1974-1981: 1989 Merger Report, 79, Table 20. Data from *Oil & Gas Journal* are used by permission.

Notes:

[1] Includes half of the neutral zone reserves.

[2] Individual Emirates of the United Arab Emirates; only Emirates that have crude oil reserves are listed.

[3] Gabon withdrew from OPEC in January 1995. It is not included in the 1995 OPEC total because the reserve numbers are for year-end.

[4] Ecuador withdrew from OPEC in December 1992.

Chapter 6

Structural Change in Bulk Transport of Crude Oil

Once crude oil is gathered, it must be transported to refineries for processing. The two primary methods of crude oil transportation are ocean transport on crude oil tankers and transport on pipelines. Crude oil tankers generally are used to transport imported crude oil into the United States, as well as to transport crude oil from Alaska to refineries in the lower 48 states. Pipelines generally move product from domestic fields or import centers to refineries. Mergers among owners of crude oil transportation assets can potentially impact the prices for crude oil transport services, the prices paid to crude oil producers, or the prices paid by crude oil refiners and other purchasers.

This chapter discusses structural trends in bulk transport of crude oil, including mergers between crude oil pipelines. Section I describes various modes of crude oil transport. Sections II and III review data related to the movement of crude oil to and within the United States. Sections IV and V analyze the relevant antitrust product and geographic markets for crude oil transport. Section VI discusses special issues in merger enforcement, including pipeline regulation and treatment of pipeline joint ventures. Several mergers involving consolidation of crude oil pipeline ownership are discussed. Section VII reviews concentration data on crude oil pipeline ownership, both nationally and in the Great Lakes Region. Section VIII discusses conditions governing entry into crude oil pipelines. Section IX concludes with a discussion of merger enforcement in crude oil marine transportation.

I. Transport of Crude Oil

After extraction, crude oil is sent to refineries, where it is processed into gasoline, diesel and jet fuel, home heating oil, and other refined products. Crude oil generally is gathered from wells by networks of small-diameter pipelines. These gathering systems take the crude oil to collection points, which are connected to larger-diameter "trunk" lines. Points where several trunk lines interconnect, and which have significant storage, are called "hubs." Hubs permit the movement of crude oil between trunk lines and are important crude oil trading centers.

Some trunk lines take crude oil directly to refineries. Others take crude oil to ports for shipment to refineries by tanker or barge. Crude oil offloaded from tankers or barges may be shipped to inland refineries via still other trunk lines.

II. Transport of Crude Oil to the United States

Tables 6-1 and 6-2 show total domestic and PADD level annual field production of crude, refinery crude oil inputs, and crude oil imports, as well as inter-PADD shipments of crude, for 1985 and 2002. As noted in Chapter 5

(Table 5-1), crude oil imports increased from 27% of United States refinery runs in 1985 to 61% in 2002. Crude oil imports are greatest in PADDs I and III, and have increased significantly between 1985 and 2002 for all PADDs, with the largest increase being for PADD III.[1] Most crude oil imports arrive in tankers, with pipelines from Canada supplying a smaller quantity to refineries in the northern tier of the United States.[2]

III. Transport of Crude Oil Within the United States

Crude oil shipments within the United States fell from 641 billion ton-miles in 1979 to 377 billion ton-miles in 2001. PADDs III and V have the greatest field production, although production in PADD V fell by about 40% between 1985 and 2002. Pipelines carried approximately 74% of domestic crude oil ton-miles in 2001, as Table 6-3 shows. Water-borne shipments were a distant second with about 26% of crude oil ton-miles. Rail and truck together accounted for under 1% of crude oil ton-miles.

Pipeline shipments of crude oil within the United States declined from 372 billion ton-miles in 1979 to 277 billion ton-miles in 2001, while shipments of crude oil by water fell from 265 billion ton-miles in 1979 to 98 billion ton-miles in 2001. The declines for both transportation modes appear related primarily to the fall in domestic crude oil production. The larger decrease in ton-miles of water-borne crude oil shipments is largely attributable to the decline of shipments along the United States coastline from Alaska, and, in particular, to the cessation of long-distance shipments from Alaska to the Gulf Coast.[3]

Virtually all domestically produced crude oil that is shipped between PADDs is transported by pipelines.[4] Domestic water shipments

[1] PADD III (Gulf Coast) was the highest volume entry point for imported crude oil over the period. PADD III's net imports increased from about 31% of apparent supply (defined as field production plus net imports plus net receipts from other PADDs minus stock change) in 1985 to about 80% in 2002. *See* Table 6-2. However, the share of imported crude oil used by refineries in PADD III (about 56%) was lower than the share of imported crude oil in apparent supply because a significant portion of the crude oil imported into PADD III was shipped to other PADDs, especially to PADD II (Midwest). As a result, the use of imported crude oil by PADD II refineries is greater than the net import rate of 28%. There was also a large increase in net imports as a percentage of apparent supply in PADD IV (Rocky Mountain region). Net imports as a percentage of apparent supply have increased in the other PADDs as well, although by smaller amounts. PADD I (New England and Eastern Seaboard) refineries, which were already highly dependent on imports in 1985, now receive nearly all their crude oil from abroad. Much of the increase in net imports into PADD V (West Coast, Alaska and Hawaii) reflects the decline in ANS production, which peaked in 1988.

[2] Imports from Canada were 527 million barrels in 2002, 16% of total crude oil imports. *See* EIA, *Petroleum Supply Annual 2002*, 271, table 21.

[3] Association of Oil Pipelines, *Pipelines and Water Carriers Continue to Lead All Other Modes of Transport in Ton-Miles Movement of Oil*, Table 2 (May 6, 2003), *available at* http://www.aopl.org/pubs/2003/ShiftReport&Letter-2003.pdf; *Pipelines and Water Carriers Continue to Lead All Other Modes of Transport in Ton-Miles Movement of Oil in 1999*, Table 2 (Feb. 6, 2001), *available at* http://www.aopl.org/news/2001/shiftreport2001.pdf. As Tables 6-1 and 6-2 show, shipments from PADD V (West Coast, Alaska and Hawaii) to PADD III (Gulf Coast) fell from 214 million barrels in 1985 to 0 in 2002. This sharp decline is largely attributable to the end of the federal export ban on ANS crude oil in 1996.

[4] Cheryl J. Trench, *How Pipelines Make the Oil Market Work–Their Networks, Operation and Regulation*, 6, *available at*

are almost entirely within PADDs, such as those between Alaska and the West Coast and Hawaii. Table 6-2 shows that the highest volume of inter-PADD shipments of crude oil is from PADD III to PADD II.[5] These shipments increased significantly between 1985 and 2002; during that same period, crude oil production in PADD II declined. PADD II is the only United States region where refineries receive a high percentage of their crude oil supply from other producing or importing areas of the United States. Pipelines from Canada also have been increasingly important sources of crude oil for PADD II refineries.

IV. Relevant Product Markets for Crude Oil Transport

Relevant product markets in which to analyze mergers affecting the bulk transport of crude oil are sometimes limited to a single mode of transport (*e.g.*, pipelines) because other modes of transport (*e.g.*, tankers) would not provide a sufficient economic alternative to render unprofitable a small but significant, non-transitory price increase. In a number of merger cases, the FTC has alleged relevant product markets for pipeline transportation of crude oil. In one case, the FTC also alleged a relevant product market for marine transportation of crude oil.[6] More than one transport mode may be included in a relevant product market in other cases, if an additional mode is found to be an economical alternative.

The ability of a hypothetical monopolist of crude oil transport into an area to profitably raise prices may be constrained by shipments of refined product into the area. Some consumption areas can obtain economically priced refined products both from local refineries that rely on crude oil transported into the area and from refined product pipelines or tankers that bring refined products from distant refineries. If a hypothetical monopolist of crude oil pipelines raised rates, the cost of producing refined products at local refineries would increase relative to the cost of importing refined products. In response, imports of crude oil could decrease, reducing local production of refined products and increasing imports of refined products. If this occurred, the profitability of a rate increase imposed by a hypothetical monopolist of crude oil pipelines would decrease. Whether such substitution at the refined products stage would prevent or defeat an anticompetitive price increase in bulk transport of crude oil into an area would depend on the circumstances of the particular case.

V. Relevant Geographic Markets for Crude Oil Transport

Relevant geographic markets in which to analyze mergers among

http://www.aopl.org/pubs/misc/Notes%20How%20Pipelines%20Make%20the%20Market%20Work.pdf. *See also* EIA, *Petroleum Supply Annual 2002*, Tables 32-33.

[5] Shipping routes that stay within a PADD (such as shipments of crude oil produced in Alaska to refineries on the West Coast) are not shown in Tables 6-1 and 6-2.

[6] *See* Section IX, *infra*, concerning Merger Enforcement Relating to Marine Transport of Crude Oil.

companies that transport bulk crude oil are usually delineated for origin and destination areas. A hypothetical monopolist of crude oil pipelines leaving an area may have market power over local crude oil producers if local producers lack economic alternatives to pipelines (such as tanker, barge, rail, or truck transport). Pipeline companies may exercise market power in an origin market by increasing their prices for transport service or by reducing the prices at which they purchase crude oil at the origin.

Similarly, a hypothetical monopolist of crude oil pipelines entering a refining area may have market power over local refineries if refineries lack economic alternatives to pipelines. Pipeline companies may exercise market power in a destination market by increasing their prices for transport service or the prices at which they sell delivered crude oil at the destination.

VI. Special Issues in Merger Enforcement Relating to Crude Oil Pipelines

A. Federal and State Regulation of Pipelines

Although refined products pipeline tariffs have become more market-based as a result of deregulation since the early 1990s, crude oil pipelines generally remain highly regulated. The FERC regulates interstate pipeline rates and requires that pipeline services be provided on a non-discriminatory basis. Proprietary interstate pipelines, which ship only products of their owners, are subject to FERC regulation but are not required to file tariffs with FERC. States regulate pipelines operating solely within their boundaries.

FERC regulations changed in 1993. Maximum pipeline rates are now set primarily by a price index system rather than the previous cost-based system.[7] Under the price index system, the maximum rate a pipeline can charge each year changes based on the change in the Producer Price Index for finished goods minus 1%. Other methods can be used to justify new tariff rates in special situations. First, a pipeline can set market-based rates if it shows that it lacks market power based on criteria established by FERC.[8] Second, a pipeline can request a cost-based rate if it can show that "uncontrollable circumstances" cause the maximum rate under the index to be insufficient to allow recoupment of its costs. Finally, negotiated rates are allowed if all shippers agree to the rate, even if it is above the index.

The introduction of market-based rates has made antitrust enforcement in

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[7] Revisions to Oil Pipeline Regulations pursuant to Energy Policy Act, Order No. 561, 58 Fed. Reg. 58753 (Nov. 4, 1993); Order on rehearing and clarification, Order No. 561-A, 59 Fed. Reg. 40243 (Aug. 8, 1994).

[8] Regarding FERC's criteria in determining whether there is sufficient competition to grant a pipeline the authority to set market-based rates, *see* Market-Based Ratemaking for Oil Pipelines, Order No. 572, 59 Fed. Reg. 59148 (Oct. 28, 1994). FERC has granted this authority only when it has concluded that there are at least four (usually, at least five) suppliers to a given area and that these suppliers have excess capacity into the area. FERC can revoke market-based rate-setting authority if market circumstances change or pipeline rates increase to supracompetitive levels. *See also* Mary Coleman, George Schink & James Langenfeld, *Oil Pipelines' Effects on Refined Product Prices*, submission to the Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products I* (Aug. 2, 2001).

pipeline transportation more important. Where FERC allows market-based rates, prices are free to increase if competition diminishes. This issue is likely to be more important for refined product pipelines than for crude oil pipelines, because all or nearly all market-based rate approvals have been related to refined product pipelines.

Even absent the use of market-based rates, however, mergers affecting crude oil (or refined product) pipelines may diminish competition. Competition between pipelines often drives rates below the regulatory caps. Pipelines also compete in non-price dimensions such as minimum batch sizes and delivery frequency, and they may compete by expanding capacity and providing connections to additional terminals and markets. Consequently, mergers may reduce competition and result in higher prices and/or lower service quality, regardless of how rates are set.

B. Antitrust Analysis of Joint Venture Pipeline Ownership Changes

Many crude oil (and refined product) pipelines are joint ventures, and several FTC enforcement actions have involved consolidation among joint venture pipeline owners. Joint ventures are a common ownership structure for pipelines because of the economies of scale and high capital costs of pipelines.[9] Appropriate treatment of joint ventures is important to determine the likely competitive effects arising from ownership changes.

Pipeline joint ventures take different forms. Some pipeline joint ventures are structured as "undivided interest" systems in which each partner acts independently in setting prices and other shipment terms. Other pipeline joint ventures are organized as "joint stock companies." Here the pipeline acts as a single competitive entity in setting prices and other terms. This distinction between undivided interest joint ventures and joint stock company joint ventures is important for antitrust analysis. An undivided interest joint venture usually has two or more owners operating from a pipeline in competition with each other.[10] A joint stock company, on the other hand, is likely to be reviewed as a single entity for purposes of competitive analyses.

A merger between two owners of an undivided interest joint venture pipeline changes market shares and concentration, eliminates one competitor, and may raise competitive concerns. The FTC alleged anticompetitive effects relating to a crude oil pipeline in two such mergers, Exxon/Mobil and BP/ARCO. Both cases involved the Trans Alaska Pipeline

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[9] For example, it is more efficient for four companies jointly to build a 24-inch line than for each to construct 12-inch lines that together would have the same capacity as a single 24-inch line. (Capacity is proportional to the square of the pipeline diameter, all else equal.) The existence of common carrier requirements may also be an incentive for the formation of joint ventures, because even an interstate line owned by a single company is required to carry the oil of any other company. *See* 1982 FTC Merger Report 230.

[10] U.S. Department of Justice, *Oil Pipeline Deregulation*, 24-25 (1986), [hereinafter "DOJ, Oil Pipeline Deregulation"]. Capacity expansion decisions are made jointly in some undivided interest pipelines. This feature constrains the ability of individual partners to compete in this dimension. Other undivided interest pipelines allow one partner to expand and control new incremental capacity if other partners do not want to participate in the expansion.

System ("TAPS"), an undivided interest joint venture crude oil pipeline with seven owners. At the time of their merger, Exxon owned 20% and Mobil owned 3%; both firms had capacity on TAPS in excess of the amounts that they needed to carry their own production; and Mobil in particular had discounted its tariffs to attract additional shipments.[11] The FTC was concerned that the merger would reduce such discounting. Similar concerns about reduced discounting were raised by the BP/ARCO merger, which would have combined BP's 50% share of TAPS with ARCO's 22% share.[12] In both cases, the FTC required divestiture of one of the two merging parties' interests in TAPS.

A merger between two owners of a joint stock company pipeline does not reduce the number of competitors, assuming that these owners do not individually have other assets in the market. However, anticompetitive effects would be possible if one of the merging firms had other assets in the market.

VII. Trends in Concentration of Pipeline Ownership

A. Changes in Concentration at the National Level

The *Oil and Gas Journal* ("OGJ") publishes an annual survey of United States crude oil and refined product pipelines. Though not linked to any market relevant for merger analysis, this survey provides an overview of concentration trends for crude oil pipelines in the United States as a whole.[13] The OGJ survey lists more than 80 pipeline companies that shipped crude oil in the United States in 2001. The number of listed companies has not changed substantially since 1985. Not all of the listed companies are distinct competitors; in some cases a parent company owns interests in several listed pipeline companies.[14] Table 6-4, which is derived from those surveys, lists the leading owners of crude oil pipelines, ranked by barrel-miles of crude oil shipments for 1985, 1990, 1995, and 2001. The total barrel-miles of each joint venture pipeline are divided among owners in proportion to their ownership shares.[15]

Enbridge is the largest U.S. crude oil pipeline company. It had more than 20% of total barrel-miles in 2001, primarily due to its ownership of the Lakehead pipeline. Lakehead is the United States segment of a pipeline running from Alberta through the United States (Minnesota, Wisconsin, Illinois, Indiana, and Michigan) and then back to

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11 ExxonMobil, Analysis to Aid Public Comment.

12 BP/ARCO, Complaint ¶15.

13 It is beyond the scope of this report to estimate changes in concentration in the many potential relevant antitrust markets in which crude oil pipelines compete. When the FTC investigates a transaction involving a significant overlap in crude oil transportation, it delineates relevant markets and estimates the effects of the transaction on concentration and competition, in accord with the framework discussed in Chapter 2.

14 For example, the BP and Amoco pipeline companies are both owned by BP; BP also owns full or partial interests in other pipeline companies listed in the OGJ survey.

15 The purpose in presenting the data in Table 6-4 is to show trends in pipeline ownership in the United States, on a national basis. If, instead, a particular market were being analyzed, it might be more appropriate to treat joint stock companies as single competitive entities, rather than dividing their capacity among owners.

Canada (Toronto and Montreal). Much of the crude oil carried by the pipeline only passes through the United States on its way to Canadian customers.

Nearly all other leading crude oil pipeline owners are major oil companies that have large crude oil production interests, refining interests, or both. In 2001, these included BP, Shell/Equilon, Marathon Ashland, and Phillips. These firms owned interests in many different crude oil pipelines, and those interests are reflected in company aggregates. BP accounted for a significant share of barrel-miles, in part because of its interest in TAPS.

Calculated on a national basis, for the United States as a whole, the HHI fell from 1,077 in 1985 to 964 in 1995 and increased to 1,225 in 2001. The impacts of mergers and joint ventures, including Shell/Texaco, Marathon/Ashland, BP/Amoco, Exxon/Mobil, and BP/ARCO, can be seen by comparing the 1995 and 2001 data in Table 6-4.[16] Phillips's acquisition of ARCO's Alaska pipeline assets as part of the settlement of the FTC's BP/ARCO case made Phillips a leading crude oil pipeline company.

B. Analysis of Changes in Concentration in the Great Lakes Region

For another perspective on crude oil transport concentration trends, it is instructive to revisit the 1982 Merger Report's analysis of crude oil supply into the "Great Lakes" region.[17] This area does not necessarily constitute a relevant crude oil destination market for any particular transaction. Historically, this region, which is part of PADD II, has been very dependent on crude oil shipments from other regions. In the early 1980s, at least 11 companies transported crude oil into the Great Lakes region by pipeline, and there were also limited water shipments. Four-firm capacity concentration was 57.4%, and the HHI was 1,135.[18]

Structural conditions in the transport of crude oil to the Great Lakes area have changed since the early 1980s. Some changes have increased the number of competitors, while others have decreased the number. The 1982 concentration estimates excluded the Lakehead pipeline, because at that time the Canadian government limited the amount of Canadian crude oil that could be exported to the United States.[19] Export restraints on Canadian crude oil no longer exist, and concentration estimates now include Lakehead. The 1982 estimates also excluded the Platte pipeline, which runs from Wyoming to the Great Lakes area, because Wyoming crude oil production was declining. However, flow on the Platte pipeline to the Great Lakes area increased significantly after the Express pipeline opened in 1997.[20] The Express pipeline brings western Canadian crude oil into Montana and Wyoming, where it is

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16 The HHI figures in Table 6-4 are not computed for a relevant antitrust market and have no direct implications for any relevant antitrust market.

17 1982 Merger Report 234-36. The "Great Lakes" area was defined as Michigan, Illinois, Indiana, Ohio, eastern Wisconsin, northern Kentucky, western West Virginia, and the extreme northwestern portion of Pennsylvania along Lake Erie. The 1982 Report also cautioned that this region did not necessarily constitute a relevant antitrust market.

18 *Id.* at 235-36.

19 *Id.* at 236.

20 Mary Coleman et al., *supra* note 8.

delivered to the Platte pipeline; the Express/Platte pipelines are now included in the concentration computations. On the other hand, acquisitions have decreased the number of competitors for crude oil transport into the region. The most important of these transactions are the Marathon/Ashland and Shell/Texaco joint ventures and BP's acquisitions of Amoco and later acquisition of ARCO.[21]

Table 6-5 lists the primary crude oil pipelines delivering to the Great Lakes area and their capacities and ownership in 2001. All are FERC-regulated common carriers. Capline is an undivided interest joint venture, in which each owner controls its share of capacity and separately posts tariffs and solicits shippers. Each owner can unilaterally expand Capline's capacity if it is willing to pay for the expansion.[22] Accordingly, each Capline owner is treated as a separate competitor in estimating concentration. Southcap, which owns 21% of Capline, is itself a joint venture owned by Unocal (50%), Marathon Ashland (30%), and Shell (20%).

The other joint venture pipeline, Mid-Valley, is a joint stock company. There is no obviously correct way to treat Mid-Valley in the HHI computation; three approaches are considered below, and the benefits and drawbacks of each are discussed. Mid-Valley might be treated as a single independent competitor, because a joint stock company operates as a single corporate entity.[23] However, that ignores the fact that BP, which owns other pipelines into the area, owns 50% of Mid-Valley. This 50% ownership interest would reduce the incentive of BP's other pipelines to compete with Mid-Valley. An alternative approach splits Mid-Valley's capacity between BP and Sun, since both companies appoint members to the board, which makes most significant business decisions.[24] That split, however, ignores the fact that the two owners do not compete in selling capacity on Mid-Valley. Another alternative assigns all of Mid-Valley to BP. That assignment ignores the role of Sun's ownership of Mid-Valley and its constraint on BP's operation of Mid-Valley and BP's other pipelines. Table 6-6 shows shares and concentration in Great Lakes delivery capacity under all three approaches.

Concentration of crude oil pipeline capacity into the Great Lakes region increased from a four-firm concentration ratio ("CR4") of 57% and an HHI of 1,135 in the early 1980s to a CR4 of 82% or 88% and an HHI between 2,371 and 2,567 in 2001.[25] The

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21 The 1982 Merger Report listed Amoco with 16% of Great Lakes crude oil delivery capacity, ARCO with 7.7%, and Mid-Valley (50% owned by Sohio in 1982) with 14.5%. 1982 Merger Report 236. BP now owns Amoco, ARCO, and Sohio's former 50% of Mid-Valley. In addition, Ashland was listed with an 8.8% share and Marathon with 4.6% in 1982. The pipeline operations of those companies are now combined into the MAP joint venture.

22 If one owner pays for a capacity expansion, that owner obtains the right to use the added capacity. Interview with Shell Pipeline Company conducted by FTC consultant George Schink (Nov. 14, 2002).

23 *See* DOJ, *Oil Pipeline Deregulation* 24.

24 When computing the HHI, Southcap's share of Capline is attributed to Southcap's owners. The ownership in Capline becomes 26.7% for Shell, 43.5% for MAP, 19.3% for BP, and 10.5% for Unocal.

25 These shares and HHIs would tend to overestimate market concentration to the extent that regional refiners could turn to water-borne shipments

competitive significance of this increase is not what the numbers suggest, however. Only a relatively small part of the increase in concentration is due to mergers.[26] Indeed, a significant part of the increase is attributable to including Lakehead pipeline and its 41% capacity share in the market. Counting all of Lakehead's capacity into the Great Lakes region may overstate its competitive position because some capacity is reserved to supply refineries in Eastern Canada. Moreover, the changes that led to inclusion of the Lakehead pipeline in the calculations for 2001 are positive developments – the entry of a large competitor into an area should increase competition. Additionally, Lakehead's owner, Enbridge, does not own any refineries in the United States, and thus does not appear to have any downstream incentive to restrict output. Consistent with its incentives, Lakehead expanded capacity three times in the 1990s, raising its mainline capacity from 1.31 MMBD in 1993 to 1.73 MMBD by 1999. Lakehead also has significant excess capacity, with current deliveries about 1.3 MMBD.[27] Separately, the 1997 reinvigoration of the Express/Platt pipeline probably had a procompetitive impact. (This pipeline is also not owned by a major petroleum company with regional refinery interests.) Large expansions of effective capacity, particularly when done by pipelines with no refinery ownership in the Great Lakes area, are likely to be procompetitive.

Other factors also mitigate potential concerns about the rise in concentration. First, the number of independent pipeline competitors into the region (8) is high enough to make anticompetitive tacit coordination difficult, especially given the pipelines' somewhat differing crude oil acquisition costs and the differences in downstream interests of the owners. Second, most of the refineries in the region have ownership interests in the crude oil lines that supply their refineries. These refinery owners tend to purchase crude oil in the fields and then transport the crude oil to their refineries. As a result of this vertical integration, these refinery owners have limited concerns about crude oil transport tariffs or supply

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of crude oil or to local crude oil production. While these alternatives might become more important if crude oil pipeline transport prices were to rise anticompetitively, they would have little impact on concentration at present prices. PADD II received no water shipments of crude oil in 2001. Crude oil production in the Great Lakes area was about 78 MBD in 2001 - about 2% of crude oil pipeline capacity to the Great Lakes area. Treating locally produced crude oil as an independent supply source would lower the HHI and the CR4 only slightly.

[26] The BP/Amoco and BP/ARCO transactions, the most recent of these acquisitions, accounted for only a small portion of the HHI change noted above. BP/Amoco reduced the number of competitors from 10 to 9. Before that merger, BP owned slightly more than 13% of Capline and 50% of Mid-Valley. Amoco owned the Amoco line, slightly more than 11% of Capline, and 24% of the Cushing line. The merger combined these interests. The BP/ARCO merger further reduced the number of competitors in this market to 8 by allowing BP Amoco to acquire ARCO's 46% interest in the Cushing line. Cushing was an undivided interest pipeline. These mergers have had the effect of increasing the current HHI by about 192 points to 2,371 if Mid-Valley and Southcap are considered independent competitors, and by about 260 points to 2,499 if the capacity shares of those entities are attributed to their owners based on ownership shares.

[27] Enbridge Energy Partners, L.P., *About Us - Enbridge Pipelines (Lakehead) L.L.C., available at* http://www.enbridgepartners.com/AboutUs/LakeheadSystem.asp. Lakehead's FERC Form 6 for 2001 shows an average flow across the United States border of 1.22 MMBD.

availability more generally.[28] Third, crude oil pipelines may face some competition from local crude oil production, water shipments, and refined product pipelines.[29] Finally, FERC regulation of crude oil pipeline rates generally does not prevent anticompetitive price increases (which may take the form of reduced discounting or poorer service) but may tend to limit the magnitude of such increases.

VIII. Entry by Crude Oil Pipelines

Crude oil pipelines are subject to economies of scale, and they require large sunk costs. Declining United States onshore production has resulted in excess capacity and the closing of many crude oil pipelines.[30] Approval and construction of new pipelines, or conversion of other pipelines to carry crude oil, typically takes at least two years. As a result, entry by crude oil pipelines typically does not satisfy the Merger Guidelines standards for likelihood or timeliness, and is not likely to deter or reverse any anticompetitive effect that might arise from a particular merger.

Nevertheless, there have been some notable additions to the crude oil pipeline infrastructure since the 1982 Merger Report. These additions include new gathering and trunk lines for Gulf of Mexico production. Also, as noted above, the Express pipeline opened in 1997 to bring Western Canadian crude oil to Montana and Wyoming. From there, the crude oil is transported to the Upper Midwest on the Platte pipeline.

IX. Merger Enforcement Relating to Marine Transport of Crude Oil

Mergers among major oil companies generally have not raised antitrust concerns in marine transport of crude oil (or in marine transport of refined products), because the world tanker industry is unconcentrated and tankers can be moved among geographic areas. According to the International Association of Independent Tanker Owners ("Intertanko"), a trade association of independent tanker owners, numerous independent firms collectively own about 80% of the world's tanker fleet.[31] Intertanko estimates that the major oil companies

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28 Mary Coleman et al., *supra* note 8.

29 Crude oil pipelines to the Great Lakes area may compete to some extent with refined product pipelines to that area, because Great Lakes refineries (which receive most of their crude oil by pipeline) must compete with product that is refined elsewhere and shipped to the Great Lakes area by pipeline. If rates on crude oil pipelines become excessive, refineries in the Great Lakes area might not be competitive with refined products shipped in by pipelines. There are several significant product pipelines to the Great Lakes area, including Explorer, TEPPCO, and Centennial. Here, this Report follows the 1982 Merger Report in defining separate markets for crude oil and product pipelines. Nevertheless, because product pipelines appear to impose some competitive constraint on crude oil pipelines, concentration may be overstated by this approach. As noted previously, water shipments and local crude oil production in this area are negligible and, therefore, unlikely to be effective competitive constraints on crude oil pipelines.

30 Some crude oil pipelines have been converted to other uses, primarily for the transport of refined products.

31 International Association of Independent Tanker Owners, *Intertanko Annual Report and Review 2002, available at* http://www.intertanko.com/about/annualreports/2002/pdf/intertanko_arr2002.pdf. Intertanko has 238 members from 37 countries. Its members own more than 2,000 tankers.

(*i.e.*, BP, Exxon, Chevron, and Shell) own only 2% of the world tanker fleet and manage another 2%.[32] A 1998 study reports that oil companies' share of the world tanker fleet is small and had been steadily declining over the past 20 years. The study attributed the decline in the size of the oil company tanker fleet to low charter rates and high owner liability.[33]

Antitrust concerns could arise under special circumstances in connection with mergers affecting marine transport of crude oil (or refined products). The FTC's complaint in BP/ARCO stated that the major producers of ANS crude oil owned or had long-term contracts for the capacity of specialized tankers that, because of Jones Act requirements, were the only legal marine transporters of crude oil from Alaska to the West Coast. The complaint also noted that smaller ANS producers, lacking their own tankers, sold their output to the majors that had tankers or to small refineries in Alaska. To eliminate competitive concerns, the consent agreement in BP/ARCO required the merging parties to divest ARCO's marine transport assets related to ANS delivery as well as the firm's onshore ANS interests.[34]

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[32] International Association of Independent Tanker Owners, *Tanker Fleet Control*, *available at* http://www.intertanko.com/search/artikkel.asp?id=4198.

[33] Commission on Oil Pollution Act of 1990 (Section 4115) Implementation Review, et al., *Double-Hull Tanker Legislation: An Assessment of the Pollution Act of 1990*, 58 (1998), *available at* http://www.nap.edu/readingroom/books/tanker/index.html.

[34] BP/ARCO, Analysis to Aid Public Comment.

Table 6-1 – Inter-PADD Crude Oil Shipments and Imports
1985
(1000's bbls)

	PADD					
Product's Origin	I	II	III	IV	V	United States
Field Production	20,961	384,082	1,546,866	229,320	1,093,324	3,274,553
Imports [1]	354,631	132,062	603,043	14,056	64,505	1,168,297
Exports	9	7,514	0	0	66,990	74,513
Net Imports	354,622	124,548	603,043	14,056	-2,485	1,093,784
Receipts from other PADDS						
PADD I	N/A	0	0	0	0	0
PADD II	1,656	N/A	25,729	8,552	0	35,937
PADD III	3,745	445,243	N/A	0	0	448,988
PADD IV	0	96,117	39,456	N/A	0	135,573
PADD V	35,142	0	214,529	0	N/A	249,671
Receipts from other PADDS	40,543	541,360	279,714	8,552	0	870,169
Deliveries to other PADDS	0	35,937	448,988	135,573	249,671	870,169
Net Receipts from other PADDS	40,543	505,423	-169,274	-127,021	-249,671	0
Stock Change [2]	-688	-5,083	34,761	-1,418	-9,245	18,327
Apparent Supply [3]	416,814	1,019,136	1,945,874	117,773	850,413	4,350,010
Refinery Inputs	420,809	999,745	1,979,066	157,629	823,492	4,380,741
Discrepancy [4]	3,995	-19,391	33,192	39,856	-26,921	30,731
Discrepancy as a Percentage of Refinery Inputs	0.95	-1.94	1.68	25.28	-3.27	0.70
Percentage of Apparent Supply						
Field Production	5.0	37.7	79.5	194.7	128.6	75.3
Net Imports	85.1	12.2	31.0	11.9	-0.3	25.1
Net Receipts from Other PADDS	9.7	49.6	-8.7	-107.9	-29.4	N/A
Stock Change	-0.2	-0.5	1.8	-1.2	-1.1	0.4
From Outside PADD	94.8	61.8	22.3	-95.9	-29.7	25.1
Imports as % of Ref Inputs	84.3	13.2	30.5	8.9	7.8	26.7

Source: Receipts from other PADDs: EIA, *Petroleum Supply Annual* Table 20 (1985); Other data: EIA, *Petroleum Supply Annual*, Tables 4, 5, 6, 7, 8 (for PADDs I, II, III, IV, V, respectively) (1985).

Notes:

[1] Imports include imports for the Strategic Petroleum Reserve.

[2] A positive stock change denotes an increase in stocks; a negative stock change denotes an decrease in stocks. Stock change includes additions/withdrawals from the Strategic Petroleum Reserve.

[3] Apparent supply equals field production plus net imports plus net receipts from other PADDs minus stock change.

[4] Discrepancy is the difference between refinery inputs and apparent supply.

Table 6-2 – Inter-PADD Crude Oil Shipments and Imports 2002 (1000's bbls)

	PADD					
Product's Origin	I	II	III	IV	V	United States
Field Production	7,458	164,635	1,174,305	102,982	647,745	2,097,125
Imports [1]	548,205	327,259	2,069,884	115,087	275,740	3,336,175
Exports	2,066	979	65	128	58	3,296
Net Imports	546,139	326,280	2,069,819	114,959	275,682	3,332,879
Receipts from other PADDS						
PADD I	N/A	0	3,043	0	0	3,043
PADD II	5,321	N/A	12,159	11,901	0	29,381
PADD III	1,002	654,447	N/A	0	0	655,449
PADD IV	0	32,747	8,112	N/A	0	40,859
PADD V	0	0	0	0	N/A	0
Receipts from other PADDS	6,323	687,194	23,314	11,901	0	728,732
Deliveries to other PADDS	3,043	29,381	655,449	40,859	0	728,732
Net Receipts from other PADDS	3,280	657,813	-632,135	-28,958	0	0
Stock Change [2]	-2,862	-9,363	34,803	-1,409	-6,604	14,565
Apparent Supply [3]	559,739	1,158,091	2,577,186	190,392	930,031	5,415,439
Refinery Inputs	562,355	1,171,806	2,594,704	189,621	937,044	5,455,530
Discrepancy [4]	2,616	13,715	17,518	-771	7,013	40,091
Discrepancy as a Percentage of Refinery Inputs	0.47	1.17	0.68	-0.41	0.75	0.73
Percentage of Apparent Supply						
Field Production	1.3	14.2	45.6	54.1	69.6	38.7
Net Imports	97.6	28.2	80.3	60.4	29.6	61.5
Net Receipts from Other PADDS	0.6	56.8	-24.5	-15.2	0.0	N/A
Stock Change	-0.5	-0.8	1.4	-0.7	-0.7	0.3
From Outside PADD	98.2	85.0	55.8	45.2	29.6	61.5
Imports as % of Ref Inputs	97.5	27.9	79.8	60.7	29.4	61.2

Source: Receipts from other PADDs: EIA, *Petroleum Supply Annual* Table 32 (2002); Other data: EIA, *Petroleum Supply Annual,* Tables 4, 6, 8, 10, 12 (for PADDs I, II, III, IV, V, respectively) (2002).

Notes:

[1] Imports include imports for the Strategic Petroleum Reserve.

[2] A positive stock change denotes an increase in stocks; a negative stock change denotes an decrease in stocks. Stock change includes additions/withdrawals from the Strategic Petroleum Reserve.

[3] Apparent supply equals field production plus net imports plus net receipts from other PADDs minus stock change.

[4] Discrepancy is the difference between refinery inputs and apparent supply.

Table 6-3 – Shipments of Crude Oil within the United States (Billion Ton-Miles)

Mode	1979 Shipments	1979 (%)	2001 Shipments	2001 (%)
Pipeline Shipments	372.2	58.1	277.0	73.6
Water Shipments	265.5	41.4	98.1	26.0
Railroad/Truck Shipments	2.9	0.5	1.5	0.4
Total	640.6	100	376.6	100

Source: Association of Oil Pipelines, Pipelines and Water Carriers Continue to

Lead All Other Modes of Transport in Ton-Miles Movement of Oil in 2001, Table 2 (May 2003).

Note: Association of Oil Pipelines data on crude oil ton-miles for pipelines reflect shipments by federally regulated interstate pipelines and an estimate of shipments by non-federally regulated state pipelines. Interstate pipelines account for about 80% of pipeline mileage and volume.

Table 6-4 – Largest Crude Oil Pipeline Companies–Share of Barrel-Miles of Crude Oil Shipments in the United States (%)

Company	1985	1990	1995	2001
Enbridge/Lakehead	19.2	18.4	20.4	22.0
BP	18.9	18.4	16.5	18.1
ARCO	10.8	8.3	7.6	
Amoco	6.8	6.1	5.9	
Shell/Equilon	5.7	5.3	5.6	12.9
Texaco	3.8	4.3	4.5	
ExxonMobil	8.8	7.5	6.3	3.6
Mobil	4.9	4.4	3.3	
Marathon/MAP	0.7	3.7	3.7	11.8
Ashland	3.4	5.0	5.4	
Phillips	1.1	1.1	1.0	6.9
Union	3.3	1.4	3.3	1.9
Sun	2.4	2.6	2.3	2.5
Express				4.2
Montreal Pipeline			0.5	3.4
Chevron	2.1	2.2	2.0	1.6
Koch	0.7	1.0	1.5	1.9
	Concentration			
Measure				
4-Firm (%)	57.7	52.6	50.8	64.8
8-Firm (%)	78.9	73.4	72.2	82.9
HHI	1,077	969	964	1,225

Sources: *Oil & Gas Journal*, “Pipeline Economics” (annual). Ownership based on FERC *Form 6*. Data from *Oil & Gas Journal* used by permission.

Table 6-5 – Crude Oil Pipelines Delivering to the Great Lakes Area in 2001

Pipeline	Owner	Capacity (MMBD)
Capline	Shell 22.5, MAP 37.2, BP 19.3, Southcap 21 (undivided interest)	1,200
Lakehead	Enbridge	1,727
Cushing-Chicago	BP	285
Amoco	BP	200
Mid-Valley	Sun 50, BP 50 (joint stock co.)	238
Mobil	Exxon	150
Express/Platte	EnCana	120
Ozark	Shell	250

Sources: Company web sites and FERC *Form 6.*

Table 6-6 – Concentration of Crude Oil Pipeline Ownership into Great Lakes Area 2001

	Mid-Valley Independent Competitor		Mid-Valley Attributed to Owners		Mid-Valley Attributed to BP	
Company	Capacity (mmbd)	Capacity Share (%)	Capacity (mmbd)	Capacity Share (%)	Capacity (mmbd)	Capacity Share (%)
Enbridge	1,727	41.4	1,727	41.4	1,727	41.4
BP	717	17.2	836	20.0	955	22.9
Shell	520	12.5	570	13.7	520	12.5
MAP	446	10.7	522	12.5	446	10.7
Exxon	150	3.6	150	3.6	150	3.6
Southcap	252	6.0			252	6.0
Unocal			126	3.0		
Express	120	2.9	120	2.9	120	2.9
Mid-Valley	238	5.7				
Sun			119			
Total	4,170	100	4,170	100	4,170	100
			Concentration			
Measure						
4-Firm (%)		81.8		87.6		87.5
HHI		2,371		2,499		2,567

Sources: Company web sites and FERC *Form 6*.

Chapter 7

Structural Change in Refining

To have value to consumers, crude oil must be refined into products such as gasoline, diesel fuel, jet fuel, heating oil, lubricants, and feedstocks. The availability of refined products from local refineries, or from refineries that can deliver to an area by pipeline or other transportation methods, has an important influence on the prices of gasoline and other refined products in that area. For this reason, as discussed in Chapter 2, analyses of overlaps in refining have been an important element of the FTC's evaluation of mergers in the petroleum industry. The analysis focuses on identifying the sources of supply to a relevant area and assessing the impact of the merger on competition among those sources of supply.

This chapter discusses structural trends in the U.S. refining industry, including the effects of mergers on industry structure. Section I provides an overview of the refining process. Section II describes trends in refinery capacity, average refinery size, and the number of refineries. Sections III and IV discuss how the FTC has analyzed relevant product and geographic markets in refinery mergers. Concentration trends are discussed in Section V. Finally, Section VI discusses the difficulties of entry into refining.

I. Background

Refineries process crude oil into a large number of refined petroleum products. Motor gasoline, distillate fuel (diesel and home heating oil), and jet fuel accounted for 81% by volume of U.S. refinery finished products in 2003.[1] This group of refined products is sometimes referred to as "light petroleum products" ("LPPs").[2] Smaller-volume refined products include residual fuel oils, petroleum coke, refinery gas, asphalt, road oil, lubricants, and petrochemical feedstocks.

Refineries are the heart of the system for bulk supply of refined petroleum products, *i.e.*, delivery of refined products to wholesale distribution terminals. A consuming area's bulk supply comes either from local refineries or from more distant refineries that supply the market by pipeline, barge, or tanker. Bulk supply markets involve large quantities, often on the order of hundreds of thousands of barrels per day. Antitrust concerns raised by mergers involving bulk supply generally have focused on LPPs, although other refined products sometimes have been the subject of investigations or enforcement action.[3]

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1 EIA, *Petroleum Supply Annual 2003*, 35, Table 3. Motor gasoline made up about 50% by volume of total finished products in 2003, with distillate fuels and jet fuel accounting for about 22% and 9%, respectively.

2 LPPs are sometimes defined to include kerosene and general aviation gasoline. Output of these two products is very small relative to the three major types of LPPs.

3 For example, anticompetitive effects in the market for base oils used to make lubricating oils were alleged in Exxon/Mobil (Complaint ¶52) and Shell/Pennzoil (Complaint ¶16).

II. Trends in Refinery Capacity, Average Refinery Size, and Number of Refineries

Since the mid-1980s, U.S. refining capacity for basic crude distillation and more sophisticated downstream processes has increased. Distillation capacity utilization rates generally increased since the mid-1980s, reaching record levels in 1997 and 1998 but easing somewhat since then. The average size and sophistication of U.S. refineries have increased, while their numbers have declined. Additions to industry capacity have occurred at existing refineries, not through construction of new refineries.

A. Distillation Capacity

Refinery capacity is often measured by the capability to process crude oil by atmospheric distillation. Atmospheric distillation, the least sophisticated and most basic of refinery processes, refers to separation of crude oil fractions by heating and cooling.[4] Table 7-1 shows EIA data on total U.S. atmospheric distillation capacity, capacity utilization, and the number of operable refineries nationally for selected years since 1949. Refining capacity has generally increased over this period. As Figure 7-1 shows, refining capacity grew at an especially high rate between 1973 and 1981, because government controls on crude prices and allocation favored small refineries and provided incentives for companies to open and operate small, inefficient refineries.[5] As a result, average refinery capacity fell between 1977 and 1980, as shown in Table 7-1. U.S. distillation capacity peaked in 1981 at 18.62 MMBD. After the government controls were eliminated in 1981, large numbers of small, inefficient refiners exited. Capacity fell in the early 1980s and was relatively flat from the mid-1980s through the mid-1990s, bottoming out at 15.03 MMBD in 1994. U.S. refinery distillation capacity has been increasing since 1994, while the number of refineries has continued to fall.

As Table 7-2 shows, the distribution of refining capacity by PADD for selected years between 1986 and 2004 has changed only slightly. Differences in the percentage decline in the number of operable refineries across PADDs were more significant, however. In 2004 PADDs I and II each had only about 60% of the number of refineries that were operable in 1986. PADDs III and V in 2004 retained just over 70% of the number of refineries that were operable in 1986, while PADD IV retained 80%.

B. Distillation Capacity Utilization

Annual refinery utilization rates, based upon atmospheric distillation capacity, have generally increased from the historical lows of the early 1980s and have exceeded 90% since the mid-1990s. Due to capacity additions and reduced demand pressures, annual utilization recently decreased several percentage

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4 Production capacity for refined products also depends on more sophisticated refinery processes downstream from the distillation stage. Indeed, capacity to produce refined products at some refineries exceeds their distillation capacity because their downstream processes rely, at least in part, on intermediates produced at other refineries. For additional detail, see the discussion of downstream refinery processes in Section II.C *infra*.

5 The small refinery bias of government crude programs during this period is discussed at 1982 Merger Report 204.

points from the 1998 peak level of 95.6% One recent survey of refinery industry executives indicated that a utilization rate of 96% is the maximum sustainable level.[6] Recent utilization levels thus appear to be several percentage points below full industry capacity, taking shutdowns for necessary maintenance into account. Of course, utilization rates at individual refineries may differ from the industry-wide rate.

Everything else equal, relatively high distillation capacity utilization implies that refinery supply responses to price increases may be smaller than would be the case if utilization were lower. Even if a refinery is close to its processing capacity, however, it may still respond to changes in relative refined product prices by changing output slates; a refinery may also still respond to changes in relative refined product prices in different geographic areas by reallocating products among geographic areas.

High utilization of distillation capacity is not without precedent. Utilization rates during the first half of the 1950s and from 1963 to 1973 were generally similar to recent rates.[7] Indeed, the relatively low utilization rates of much of the 1970s and 1980s were arguably more anomalous, reflecting the demand-decreasing effects of the high product prices of much of the period and the excess refining capacity induced by government programs. Moreover, although sustained high utilization rates may be associated with equipment failure and unanticipated shutdowns, several operational changes in recent years have encouraged higher utilization rates. These changes include increased hardware reliability, more efficient maintenance procedures, and extended run times due to better-performing catalysts. Better market information and transparency may have encouraged higher utilization rates since they reduce the risks of maintaining just-in-time operations.[8]

Refinery capacity utilization varies seasonally because demand for gasoline is seasonal, being greater in the summer months.[9] As a result, refineries' supply responses to changing prices may be smaller during the peak demand season. During off-peak times, distant refineries may have unused capacity that could be used to increase shipments to an area, and pipelines may have space for increased shipments. In contrast, during peak demand times, a distant refinery may have less ability to divert supplies to an area, either because it lacks production capacity or because pipelines are full. The competitive effect of a merger can thus potentially differ between peak and off-peak seasons.

C. Downstream Refinery Capacity

A refinery's production capabilities are not solely measured by distillation capacity. Holding distillation capacity constant, refineries vary

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[6] D.J. Peterson & Sergi Mahnovski, Report of Rand Science and Technology, *New Forces at Work in Refining* 43 (2003) [hereinafter "Rand Report"].

[7] EIA, Annual Energy Review 2002, Table 5.9.

[8] Rand Report at 42.

[9] For example, in 2002 U.S. refinery crude oil consumption peaked in July with a monthly average of 15.43 MMBD. (93.5% of capacity). Monthly refinery crude oil consumption in 2002 was at its lowest level in February, 14.51 MMBD, which was 86.6% of capacity. EIA, *Petroleum Supply Annual 2002: Volume 2*, Table 16 (June 2003).

markedly in their ability to process different kinds of crude oil and to produce different types of refined products. Most refineries have not only atmospheric distillation units but also "downstream" processing units that break down, build up, or otherwise treat the hydrocarbon molecules in crude oil.[10] Downstream processing units enable a refinery to use a wider range of crude oils and to make a broader array of refined products, including fuel with more demanding specifications. Increased downstream capabilities allow refineries to use lower-quality, lower-priced crude oil.[11] Refineries with more downstream capabilities also typically produce more gasoline from a given barrel of crude oil.

Downstream capabilities of U.S. refineries have increased significantly since the 1980s. Investments in downstream processes have been motivated by the strong demand for light products such as gasoline and diesel, which has provided an incentive to increase the yield of these products from a given barrel of crude. Downstream processing units also have been important in allowing refineries to meet new environmental regulations for fuel products. Table 7-3 lists national operable capacities for some important downstream processes for selected years between 1985 and 2003.[12] The table shows that the percentage increase in capacity for four of the six downstream processes was greater than that for atmospheric distillation between 1985 and 2003.

Sophisticated refineries are more flexible than less sophisticated ones and, as a result, have greater ability to change crude input slates and refined output slates in response to changes in relative prices. The extent of refinery flexibility has competitive implications; for example, greater refinery flexibility may imply broader product markets.

D. Average Refinery Size and Number of Refineries

The average distillation capacity of operable U.S. refineries increased from about 72 MBD in 1986 to 113 MBD in 2004. As Table 7-1 shows, this increase in average size continues a long-term trend going back more than 50 years. All PADDs have seen increases in average refinery size, but these increases have not been equal. Consistent with the greater percentage

[10] In addition to the output of their own distillation units, some refineries rely to some extent on other refineries for intermediates for feedstocks into their downstream processing units. At one extreme is Hess's Port Reading, New Jersey refinery, which has no crude distillation capabilities. This refinery processes intermediates from other refineries in a fluid catalytic cracking unit with a capacity of 62 MBD to produce gasoline and other fuel products. *See* Amerada Hess Corp., *Refining and Marketing*, *available at* http://www.hess.com/RM/refining.htm. http://www.hess.com/worldwide_refining.html.

[11] National Petroleum Council, *U.S. Petroleum Refining* 28-29 (June 2000).

[12] EIA data used in Table 7-3 refer to end-of-year measurements and are based on refinery stream day capacity (which are maximum output levels), not calendar day capacity (which measures capacity under normal operating conditions, taking planned downtime into account). Vacuum distillation is further distillation under reduced pressure of the bottom fractions from atmospheric distillation. Thermal cracking converts heavier, larger molecules into lighter, smaller ones and is effective in boosting yields of LPPs such as gasoline. Catalytic cracking and catalytic hydrocracking are more advanced cracking techniques used to upgrade heavier materials into lighter, higher value products. Catalytic reforming is a catalytic process to increase octane values by rearranging oil molecules, while hydrotreating is a catalytic process to upgrade petroleum fractions and to remove contaminants such as sulphur.

reduction in the number of refineries combined with relatively constant shares of national refining capacity noted above, PADDs I and II saw larger increases in the average size of their refineries between 1986 and 2004 compared to other PADDs, especially PADDs IV and V.[13]

The trend toward larger refineries is also shown in Table 7-4, which compares the size distributions of *operating* (vs. operable) refineries on January 1, 1986 and January 1, 2004. In 1986, 56% of refineries (accounting for 15.3% of U.S. capacity) were 50 MBD or smaller, while in 2004 only 31% of refineries (accounting for 5.4% of U.S. capacity) were 50 MBD or smaller. Many of the smallest refineries in 2004 were asphalt or roofing plants, not typical refineries.[14] In 1986, 10% of refineries (accounting for 39% of U.S. capacity) were 200 MBD or larger, while by 2004, 22% (accounting for 54% of U.S. capacity) were 200 MBD or larger. These changes continue a long-term trend toward larger refineries.[15] The change in the size distribution of refineries occurred through the closure of many small refineries, the expansion of many of the refineries that remained open, and, in a few cases, the combination of adjacent refineries.

Despite the trend toward greater average size, there remains a wide range in capacities among operating refineries. As Table 7-4 shows, 14 refineries were operating in 2004 with capacities of 10 MBD or less. The largest U.S. refinery as of January 2004, Exxon's Baytown, Texas facility, has a capacity of 557 MBD.

The capacities of many smaller U.S. refineries remain below levels generally considered to be efficient scale based on refinery operations alone. The 1982 Merger Report stated that the minimum efficient scale ("MES") for a refinery – the smallest size at which most scale economies are achieved – was usually placed between 150 and 200 MBD.[16] This MES range, which was based on engineering studies, is roughly equivalent to the range suggested by a survey of refinery operating costs in 1998.[17] According to this survey, operating costs per barrel of distillation capacity utilized tend to flatten out somewhere between 115 and 183 MBD, although there is considerable variance in per-unit operating costs for refineries in the same size cohort.

Cost disadvantages from low-scale operation may be offset by other factors such as proximity to crude producing or product consuming areas

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[13] Based on data from Table 7-2, average refinery size increased by 53 MBD in PADD I and by 61 MBD in PADD II between 1986 and 2004. The corresponding increases in PADDs III, IV, and V were 49, 10, and 28 MBD, respectively.

[14] Jeannie Stell, ed., *2002 Worldwide Refining Survey*, OIL & GAS J. 68 (Dec. 23, 2002).

[15] Going back even further, average refinery size in 1918 was only about 5 MBD, rising to an average of about 9 MBD by 1940, the year when the number of operating refineries in the U.S. peaked at 461. By 1950 average refinery size had increased to about 19 MBD. *See* National Petroleum Council, *U.S. Petroleum Refining* 22-23, Appendix C-1 (June 2000). The trend toward larger refineries was interrupted during the 1970s and early 1980s because of government controls on crude oil prices and allocation, which, as noted above, favored the operation of smaller refineries. *See* note 5, *supra*.

[16] The 1982 Merger Report also noted that some analysts believed that major scale economies were exhausted at levels as low as 60 MBD. 1982 Merger Report 191-93.

[17] National Petroleum Council, *U.S. Petroleum Refining* 28-29, Figure I-5 (June 2000).

(which imply transportation cost advantages) or an ability to serve niche product markets.[18] While some smaller refineries may be viable and competitively significant as a result, the trend toward larger refineries strongly suggests that these offsetting factors are becoming less important. For example, locational advantages of smaller, inland U.S. refineries may have been reduced because of the decline in domestic onshore crude production and the entry of new product pipelines. In addition, the large capital investments required under recent environmental regulations may disadvantage smaller refineries, which lack economies of scale relative to larger ones.[19] Accordingly, competitive pressures appear to be favoring refineries of larger scale in the long run.

Significant multi-plant scale economies in refining also exist. In some cases, firms can reduce operating costs by running two or more refineries jointly.[20] Technical constraints that otherwise would be binding if refineries were run in isolation can be relaxed if a firm operates in multiple sites as a single refinery.[21] There are several potential sources of efficiencies. First, there may be volume-related purchase or transport benefits in obtaining crude oil for multiple refineries. Second, a refiner may be able to exchange intermediate feedstocks among nearby refineries to utilize each of the refineries' various units more fully and to produce the highest value finished products.[22] Third, a refiner may be able to blend the outputs from each of the refineries to increase the amount of higher value finished products, such as gasoline or diesel fuel, that the refineries can produce. Finally, multi-refinery operation may permit capital savings when process upgrades are made. For example, when a refiner considers

[18] Indeed, the 1982 Merger Report noted that MES estimates based on the survivor test suggested MES values well under 100 MBD. 1982 Merger Report 191 n.45. The survivor test examines changes in the size distribution of firms or plants over time: entities whose sizes account for increasing shares of industry output over time are considered to be efficient, while those of sizes suffering declining shares are considered to be relatively inefficient.

[19] National Petrochemical & Refiners Association submission to the Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products II* 29-30 (May 8-9, 2002).

[20] The refineries need not be close together to achieve efficiencies. For example, the Tesoro refinery in Anacortes, Washington, processes heavy vacuum gas oil from Tesoro refineries in Alaska and Hawaii, which do not have sufficient downstream capacity to process such residual oils. Tesoro Petroleum Corporation, *Annual Report 2001*, 6, 8.

[21] For example, ExxonMobil states: "Regional refinery clusters enable ExxonMobil to capture supply and logistics efficiencies beyond those available through physically integrating facilities. Optimizing refineries as a 'circuit' improves decisions on crude purchases, feedstock transfers, product blending, sales, and marine transportation. This 'virtual' integration of our operations captured about $100 million of enhancements in the U.S. Gulf Coast during 2001 and $75 million in Japan (ExxonMobil share)." Exxon Mobil Corporation, *2001 Financial and Operating Review* 68, *available at* http://www2.exxonmobil.com/corporate/newsroom/publications/c_fo_01/pdfs/downstream_refine.pdf.

[22] For example, the Valero website describes one of the benefits of having multiple refineries in Texas: "The Texas City plant also adds synergistic value to our operations by providing intermediate feedstock to the Corpus Christi refinery's heavy oil cracker and the Houston refinery's FCC [fluid catalytic cracking] unit." Valero Energy Corporation, *Texas City Refinery*, *available at* http://www.valero.com/Visit+Our+Refineries/Texas+City.htm. Similarly, Marathon Ashland operates its seven refineries in PADDs II and III as a single system, using pipelines and other connections to move feedstocks among the refineries to take advantage of the processing strengths at individual refineries. *See* Marathon Ashland Petroleum LLC, *About Us - Refineries*, *available at* http://www.mapllc.com/about/refining.htmlhttp://www.mapllc.com/about.

adding new downstream processing units, it may be more efficient to add one large unit at one refinery and ship intermediate feedstock from a second refinery rather than build separate smaller units at the two refineries.[23]

Gasoline production illustrates some of the advantages of a multi-refinery operation. Finished gasoline is a complex blend of various intermediate refinery streams that must meet finished gasoline specifications, such as sulphur content, Reid Vapor Pressure, and octane. Different refineries may have different constraints on the specifications of gasoline that can be produced. For example, it may be possible to increase the total amount of gasoline produced, or to produce it at lower cost, by blending higher octane, higher sulphur gasoline from one refinery with lower octane, lower sulphur gasoline from another refinery. The advantages of multi-refinery operation in allowing a firm to exchange intermediates probably have become more important since the mid-1980s because of the larger number of environmental mandates for gasoline specifications.

As average refinery size has increased, the number of U.S. refineries has declined. As shown in Table 7-1, the number of operable refineries fell from 223 in 1985 to 149 in 2004, continuing a trend at least 60 years old. Refinery closures have overwhelmingly involved small, relatively unsophisticated facilities. Of the 57 refineries closed since 1990, 23 had distillation capacities of 10 MBD or less, only seven had capacities greater than 50 MBD, and only two had capacities greater than 100 MBD.[24] Four of the refineries listed as closed (including both of those with capacities over 100 MBD) were not actually shut down; rather, they were merged with adjacent refineries so that their capacity did not exit the market.[25] In addition to being small, many of the refineries that were closed could not produce higher valued refined products. About one-third had no

[23] Although firms frequently have achieved these types of multi-plant synergies through purchase and sale agreements, joint input purchasing arrangements, or product exchanges, transaction cost considerations in some instances require a merger or joint venture to achieve these synergies or to realize them more fully. Firms may recognize the gains from trade but differ on how to value the inputs each would provide. For example, inputs such as refined product feedstocks that are lightly traded may be particularly difficult to value because they do not have a widely acknowledged market price. Difficulties in specifying how the gains to trade are to be apportioned will increase with the number of negotiating parties; achieving efficiencies contractually across several refineries, for example, is likely to be more difficult than if only two refineries are involved. A related, well-recognized circumstance under which a merger may achieve what a contract cannot is when parties are unable to specify contractual contingencies sufficiently, perhaps because the likelihood of different future outcomes is too difficult to predict or agree upon. Contracts that are incomplete in addressing parties' obligations under important contingencies carry risks that may be unacceptable to one or more of the negotiating parties. The risks of entering into incomplete contracts are also likely to be magnified when firms must make significant sunk investments that are specific to the proposed exchange. *See* JEFFREY CHURCH & ROGER WARE, INDUSTRIAL ORGANIZATION: A STRATEGIC APPROACH 70-76 (2000).

[24] National Petroleum Council, *U.S. Petroleum Refining* 22-25 (June 2000); NPC estimates updated for 2001-2004 based on EIA, *Petroleum Supply Annual*, for the years 2000 through 2003.

[25] These refineries are: (1) Shell in Carson, California, which was merged into the adjacent Unocal refinery; (2) Chevron in Philadelphia, which was merged with an adjacent Sun refinery; (3) El Paso Refining in El Paso, Texas, which was merged into a nearby Chevron refinery; and (4) Southwest Refining in Corpus Christi, Texas, which merged with a Koch refinery.

downstream capacity.[26] The National Petroleum Council found that about half of the refineries closed between 1990 and 1999 did not have facilities normally associated with producing finished gasoline.[27] Some recent closures have been related to the large investments required to meet new fuel specifications. For example, in 2001 Premcor closed its Blue Island, Illinois refinery, which had a crude distillation capacity of about 76 MBD, because it would have had to invest about $70 million to meet new refined product specifications.[28] In October 2002, Premcor shut down its 70 MBD Hartford, Illinois refinery for similar reasons.[29]

III. Relevant Product Markets for Refinery Mergers

To analyze the competitive effects of mergers between refineries or between refineries and refined product transport companies (principally pipelines), the FTC typically delineates markets for the bulk supply of refined petroleum products. Each LPP may constitute a separate product market for purposes of antitrust analysis. There is no (or very limited) demand-side substitution among motor gasoline, distillate fuel, and jet fuel. Narrower demand-side product markets are also possible. Government-mandated product specifications may be the basis for relevant antitrust product markets. For example, the FTC has delineated markets for CARB gasoline for purposes of analyzing a number of mergers affecting bulk supply in California. In Exxon/Mobil, the FTC delineated a relevant market for JP-5 jet fuel, used in Navy jets, for which commercial and Air Force jet fuels were not sufficiently close substitutes. Also, on the supply side, competing refineries often have significantly different capabilities to produce individual refined products, and different capabilities to change product slates in response to changes in relative product prices.

Nevertheless, it can be appropriate to delineate a market for LPPs as a group in some cases. This may be a relevant market because there is supply-side flexibility among refined products at refineries and because there is considerable flexibility for product pipelines to carry different LPPs.[30]

IV. Relevant Geographic Markets for Refinery Mergers

The delineation of relevant antitrust geographic markets for the bulk supply of refined products is case-specific and depends on the location and characteristics of the involved refineries and conditions relating to bulk transport. These factors are discussed in Chapter 2.

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26 EIA, *Petroleum Supply Annual 1990*, Table 38.

27 National Petroleum Council, *U.S. Petroleum Refining* 23 (June 2000).

28 Joseph Loftus, et al., *Special Report: Refining*, OIL & GAS J. 60 (Mar. 19, 2001). This article also noted that several additional refineries would close in the future because of the cost of meeting new product specifications.

29 Jeannie Stell, ed., *2002 Worldwide Refining Survey, supra* note 14, at 63. In April 2003, ConocoPhillips agreed to buy various operating units at the Hartford refinery and integrate their operation into its nearby refinery at Wood River, Illinois. PLATTS OILGRAM NEWS (Apr. 22, 2003).

30 Even under circumstances supporting a relatively broad product market such as all LPPs, the potential for anticompetitive effects may differ somewhat across individual products within the market.

As noted there, refineries frequently serve more than one market.

Relevant geographic markets for various LPPs alleged in FTC enforcement actions since the mid-1980s have been much smaller than entire PADDs. As the list of FTC enforcement actions in Table 2-5 shows, alleged relevant geographic markets for one or more major types of LPP have been: California (Shell/Texaco, Exxon/Mobil, Chevron/Texaco, Valero/UDS), northern California (Valero/UDS), the Pacific Northwest (Shell/Texaco, Chevron/Texaco), eastern Colorado (Conoco/Asamera, Conoco/Phillips), northern Utah (Conoco/Phillips), and the St. Louis metropolitan area (Chevron/Texaco).

Relevant geographic markets for other refined products may not be the same as those for major types of LPPs. Smaller-volume, higher-value refined products may trade in broader geographic markets. For example, in the Exxon/Mobil complaint, the FTC alleged a geographic market consisting of the United States and Canada (and unspecified areas contained within) for the sale of paraffinic base oil and a world market for the sale of jet turbine oil.

For a given product, the size of relevant geographic markets may vary among regions. For example, some areas have relatively limited bulk supply options. Pipeline and water-borne capabilities may be limited, or regulatory requirements for product specifications may restrict the number of potential suppliers. Other areas may have a wider variety of competitive options. Thus, the geographic markets alleged in antitrust complaints may vary depending on a number of factors.

Inter-PADD shipment patterns suggest competitive linkages (or lack of) between producing and consuming areas for refined products. Overall, bulk supply relationships between refining and consuming areas in the United States have not changed much since the mid-1980s. Tables 7-5 and 7-6 show refinery production, foreign imports and exports, and receipts from other PADDs for the three major LPPs, broken down by PADD, for 1985 and 2003, respectively. “Product supply” approximates the consumption of LPPs within the designated area. Note that refinery production has increased in each area even though, as discussed previously, the number of refineries has decreased between 1985 and 2003.

PADD I is the largest consuming PADD. It is heavily dependent on bulk supply from other PADDs and from foreign imports. Net receipts from other PADDs accounted for about 52% of PADD I consumption in 2003, while net foreign imports accounted for another 16%.[31] The lion’s share of net receipts from other PADDs came from pipeline and water shipments from PADD III. Nonetheless, PADD I refinery output increased more than area consumption between 1985 and 2003, resulting in a reduced dependence on out-of-PADD

[31] The northern and southern parts of PADD I have significantly different supply sources of light refined products. The southern part (Maryland and below) has few refineries and is very dependent on shipments on the Colonial and Plantation pipelines and water shipments from PADD III. The northern part of PADD I (Pennsylvania and above) has greater refinery production (although that production is not sufficient to meet local demand) and also receives a portion of its supply from imports and from PADD III.

sources from about 72% in 1985 to 68% in 2003.

PADD II is the second largest producing and consuming PADD for LPPs. PADD II also depends on large inter-PADD shipments to meet consumption needs, although much less so than PADD I. Refineries in PADD III, and to a lesser extent those in PADD I, are the main sources of shipments into PADD II; net imports into PADD II from outside the United States are negligible. PADD II's dependence on shipments originating outside the area increased slightly from 22.8% of area consumption in 1985 to 24.1% in 2003. PADD III refineries access the Midwest by a number of major product pipelines and by barge up the Mississippi River. In its investigation of the Midwest gasoline price spikes of 2000, the FTC concluded that the output of PADD III refineries is the marginal source of supply constraining bulk supply product prices in the Midwest.[32] Recent expansions of existing product pipelines and the opening of a new pipeline (Centennial) may increase PADD III shipments into PADD II in the future.

PADD III is by far the leading PADD for the refining of LPPs, accounting for more than 45% of total U.S. refinery production in both 1985 and 2003. With refinery production much in excess of its consumption needs, PADD III is a major exporter of LPPs, particularly to PADDs I and II. PADD III's position as an exporter to other PADDs was essentially the same in 1985 and 2003, although absolute quantities increased.

PADD IV is the smallest consuming PADD. It accounted for only about 3.5% of total U.S. consumption of LPPs in 2003. PADD IV receives shipments from PADDs II and III, and to a lesser extent from foreign imports, that represent about 9% of area consumption. These shipments into PADD IV are up considerably from 1985, when they represented only about 2% of PADD IV consumption. The closer integration of PADD IV with PADD III is one of the more notable changes in shipment patterns since the mid-1980s. As with PADD II, new product pipelines or increased capacity of existing lines may result in additional shipments into PADD IV from neighboring PADDs in the future.

PADD V, the third largest producer and consumer of refined products, is relatively isolated from other areas in the U.S. Net shipments of LPPs into PADD V from outside were only 4.4% of area consumption in 2003, down slightly from 6.4% in 1985. The absence of major product pipeline connections between its large population areas and PADD III refineries, the CARB fuels standards for its largest consuming state, and the fact that two of its states (Alaska and Hawaii) are not contiguous with the rest of the country contribute to PADD V's special, stand-alone character.

In sum, the FTC's enforcement experience indicates that in some cases

[32] Midwest Gasoline Report 9. "Marginal supply" refers to the production just drawn to the market at the current price: if price were to fall, this production would be withdrawn from the market. In a merger context, antitrust analysts are also interested in marginal supply assuming a "small but significant and nontransitory" increase in price. As prices rise, a marginal supplier may be an incumbent firm that produces more at higher marginal cost, or a firm not already in the market that becomes willing to supply some production to the market because the higher price now covers marginal cost.

relevant geographic markets for bulk supply of refined products can be relatively narrow – for example, when there are specially mandated fuel product specifications or constraints on pipeline capacity. Nonetheless, there are important competitive linkages across broad areas of the country. The Rockies and the West Coast are more isolated from other parts of the country on the basis of refined products shipments. Though PADD IV has become somewhat more connected to PADDs II and III, the overall product shipment relationships among PADDs have not substantially changed since 1985.

V. Refinery Concentration

Refineries are often key competitive entities in relevant bulk supply markets because they produce light refined products. Pipelines, however, can have significant control over bulk product flows and often must be taken into account in a competitive analysis. In some cases a pipeline may have more control over the pricing and volume of products entering a market than do the refiners supplying the pipeline. This might be true, for example, if a pipeline controls a significant portion of refined product output into a market and is not restrained by FERC rate caps.[33] Pipelines can also be key competitors in bulk supply markets even when rate caps are binding. For example, pipeline owners have considerable discretion to make capacity additions. Suppose a merger would combine a product pipeline with a refinery that supplies the same geographic market. If the pipeline tended to be full much of the year, the merged firm might have less incentive to expand it because of the economic impact upon the acquired refinery. Thus, both refineries and pipelines are often critical in the analysis of bulk supply markets. In some cases, bulk supplies arriving by water are also important to the analysis.

EIA data on atmospheric distillation capacity formed the basis for refinery concentration estimates in the two previous Merger Reports. This update also uses operating distillation capacity to compute refinery concentration.[34] Table 7-7 summarizes capacity concentration trends for selected geographic areas between 1985 and 2003, using end-of-year data.[35]

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33 As discussed in Chapter 8, FERC has allowed some product pipelines to charge market-based rates.

34 Concentration estimates based on operating capacity could be overstated if idle refineries would reopen in response to anticompetitive prices. At the end of 2003, EIA listed 146 operating refineries, with only three idle refineries that could be reopened. Operating refineries had total capacity of 16.76 MMBD, while idle refineries had a combined capacity of 135 MBD – less than 1% of total industry operating capacity. EIA, *Petroleum Supply Annual 2003*, 80, Table 36. Inclusion of idle refining capacity therefore would not change HHI estimates significantly.

35 There are several refining joint ventures in the U.S. Marathon Ashland, the largest such joint venture with seven U.S. refineries, is treated as a single competitive entity for the capacity share calculations because it combined all U.S. refining assets of Marathon and Ashland and sells refined products as a single entity. Shell owns a 50% interest in Motiva (Saudi Aramco owns the remaining 50%) and 50% of Deer Park Refining (Pemex owns the remaining 50%). The entire capacities of these two joint ventures are attributed to Shell in calculating capacity shares because Shell appears to control the pricing and output decisions of these refineries. Saudi Aramco and Pemex do not own any other refining assets in the U.S. and do not appear to play a significant role in selling the output. To the extent that Saudi Aramco and Pemex are significantly involved in setting price and output terms for these joint ventures, the HHI estimates presented here may be overstated.

Exxon and PDVSA (Petroleos de Venezuela) have a 50/50 joint venture involving a refinery in

Some of the areas in Table 7-7 are grouped to reflect the competitive linkages suggested by inter-PADD patterns of shipments discussed above. Table 7-7 also provides four-firm concentration ratios (CR4) and eight-firm concentration ratios (CR8) for some areas back to 1969, where available from the 1989 Merger Report.

The distillation-capacity-based concentration measures in Table 7-7 are presented for descriptive purposes, not as a basis for assessing changes in concentration in relevant antitrust markets and the potential impact of mergers on those markets. These measures have serious limitations for assessing the potential impact of mergers. First, the geographic areas in Table 7-7 generally do not correspond to relevant geographic markets for the purposes of antitrust analysis. Second, a relevant geographic market comprises an area where prices might rise anticompetitively. Competitors in such relevant markets are not necessarily the same as the firms located in the area. For example, consider California, an area that has been alleged by the FTC as a relevant geographic market for several mergers involving refineries. The figures in Table 7-7 reflect only distillation capacity within California, but participants in a relevant antitrust market for California's CARB-grade gasoline may include refiners located elsewhere who ship product into the state.[36] Third, the concentration measures presented in Table 7-7 generally are not based on the appropriate capacities. Distillation capacity measures a refinery's crude input capacity, not the capacity to make the specific product or products of antitrust interest. There is no simple relationship between a refinery's distillation capacity and its capacities to produce individual refined products. As discussed earlier, a focus on crude distillation capacity tends to give too little weight to refineries with sophisticated downstream processes, at least with respect to higher-valued products such as gasoline.

Concentration measures would be more useful if they were based on output or capacity for specific types of refined products.[37] For example, if CARB gasoline were the focus of interest, market concentration based on current output would exclude the output of other refined products that California (and other) refiners make from processing crude oil. Some California refiners that have distillation capacity but make products other than CARB gasoline (for example, smaller refiners that make only lower-valued products such as asphalt) would be excluded from the relevant market altogether. Aside from estimates reported in FTC merger complaints, such concentration measures based on output or capacity data are not

Chalmette, Louisiana. Lyondell-Citgo is a 50/50 joint venture between Lyondell and PDVSA involving a refinery in Houston, Texas. For the purpose of calculating shares, the capacities of these last two joint ventures were split between owners, since each owner is active in U.S. refining.

36 For example, in alleging a relevant market for bulk supply of CARB gasolines in the Valero/UDS merger, the FTC included as market competitors not only California refineries but also refineries located in Anacortes, Washington. Valero/UDS, Complaint ¶¶ 13-16.

37 Antitrust analysis also would take into account the extent to which refiners might shift from producing one product to another in response to changes in relative prices.

publicly available.[38] Finally, as stated above, pipelines or water-borne shipments often have a significant competitive role in bulk supply markets, but they are not reflected in Table 7-7.

A. Concentration at the National Level

Refining concentration for the United States as a whole has remained low (under 1,000) throughout the last two decades. The national HHI was 493 in 1985. It decreased slightly from 1985 to 1996 and then increased modestly to 728 in 2003.[39] Mergers contributed to the increases since 1996. Table 7-8 summarizes the effects on national shares of distillation capacity of the largest refinery mergers since 1996. The 2003 data in Table 7-8 reflect divestitures the FTC ordered in connection with mergers.[40] The existence of those divestitures is one reason why the sums of the pre-merger shares of the merging companies often exceed the post-merger shares of the merged companies. Another reason is that some companies have sold refineries for independent business decisions. For example, Mobil sold its Paulsboro, New Jersey refinery to Valero. BP has sold several refineries: (1) Belle Chase, Louisiana to Tosco (now ConocoPhillips); (2) Lima, Ohio to Clark (now Premcor); (3) Mandan, North Dakota to Tesoro; (4) Salt Lake City to Tesoro; and (5) Yorktown, Virginia to Giant Industries. Equilon sold its Wood River refinery to Tosco (now PhillipsConoco) and its El Dorado refinery to Frontier.

B. Concentration at the PADD Level

The HHI for refineries located in PADD I has increased between 1985 and 2003 by more than 900 points to 1943, in 2003. Most of this increase occurred between 1985 and 1996 as a result of three acquisitions: (1) Sun's 1988 purchase of Atlantic's Philadelphia refinery, (2) Sun's 1994 purchase of Chevron's Philadelphia refinery, and (3) Tosco's 1996 purchase of BP's Marcus Hook, Pennsylvania refinery. Estimates of concentration for PADD I refining capacity alone, however, are not useful for assessing bulk supply competition within PADD I. As discussed above, PADD I overall is heavily dependent on supplies from PADD III refineries and, to a lesser but still significant extent, imports from the Caribbean and Europe. Analysis of bulk supply competition in PADD I must reflect all economically available supply options. To reflect the competitive constraint imposed by PADD III refineries, and consistent with the previous Merger Reports, capacity concentration estimates are presented for PADD I and PADD III combined. The HHI for that combined area increased by 346 points to 919 between 1985 and

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38 *See* Table 2-5 for summary relevant market concentration data contained in FTC merger complaints.

39 There were also increases in 4-firm and 8-firm capacity concentration ratios, with the top 4 refiners accounting for 44.4% of capacity in 2003, up from 34.4% in 1985, and the top 8 accounting for 69.4%, up from 54.6%.

40 One factor in the decline of the HHI from 743 in 2002 to 728 in 2003 was the divestiture of two refineries by Conoco/Phillips in 2003. The FTC consent order in the Conoco/ Phillips merger required two refinery divestitures: the former Conoco refinery in Colorado was sold to Suncor and the former Phillips Utah refinery was sold to Holly. *See* Conoco/Phillips, Order ¶¶ I.Q, I.BA. *See also* Letter Approving Divestiture of the Colorado Assets to Suncor Energy, Inc., and Letter Approving ConocoPhillips's Proposed Divestiture of the Woods Cross Assets to Holly Corporation.

2003. Thus, concentration for PADDs I and III combined remains low.[41]

The difference between concentration estimates for PADD I alone and for PADDs I and III combined is attributable to several factors. PADD III capacity is relatively unconcentrated and is much greater than PADD I capacity. Furthermore, individual refiners' positions in PADDs I and III differ significantly. For example, the two leading refiners in PADD I are Sun and ConocoPhillips (by virtue of its 2001 acquisition of Tosco). In 2003, Sun had about 30% of PADD I capacity, while ConocoPhillips had about 26%. The two firms had much smaller shares of PADD III capacity – none in the case of Sun and 11% in the case of ConocoPhillips in 2003. A number of other refiners, including ExxonMobil, Citgo, and MarathonAshland, have significant operating refining capacity in PADD III but none in PADD I. Consequently, the latter group of PADD III refiners would have incentives to ship additional product into PADD I should leading PADD I refiners reduce output anticompetitvely (so long as other delivery alternatives available to these PADD III refiners are less attractive).[42] Imports from the Carribean and Europe, to the extent not controlled by incumbents, may act as an additional constraint on prices in PADD I.[43] Import volumes have been small but may increase significantly in the future. EIA projects that refined product imports into PADD I will increase from 1.6 MMBD in 2001 to 6.7 MMBD in 2025.[44]

The HHI for PADD II refinery capacity remains low, having increased from 681 in 1985 to 1,063 in 2003. The 1982 and 1989 Merger Reports also provided refinery concentration

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41 Quantifying the competitive significance of PADD III refineries in PADD I by adding all PADD III capacity in calculating concentration implicitly assumes that any point within PADD I can be as easily supplied by PADD III refiners (or shippers) as any other point (an assumption that also applies to PADD I refineries). It is clear that large parts of PADD I, including many of the more heavily populated areas between northern Virginia and the New York City area, are within easy reach of PADD III product transported by major pipelines and marine shipments. These shipments into PADD I are identified by EIA prime supplier data, from which state-level gasoline wholesale concentration can be calculated. These concentration estimates, which are discussed at greater length in Chapter 9, are based on "first sales" of gasoline into a state by refiners and other marketers. For example, about 95% of PADD I refining capacity is located in Pennsylvania, New Jersey and Delaware. While PADD I concentration in 2001 was about 2,100 points (and refinery concentration in just Pennsylvania, New Jersey and Delaware would be even higher because the three small refineries located elsewhere in PADD I are owned by firms with no refineries in Pennsylvania, New Jersey or Delaware), wholesale gasoline concentration in 2001 in those three states was lower (1,334 in Pennsylvania, 1,075 for New Jersey and 1,258 for Delaware), reflecting wholesale sales of gasoline imported into those states but not refined there.

Real-world supply logistics are, of course, much more complicated than under the simplifying assumption of equal access to all delivery points within a PADD. As noted in Chapter 2, FTC complaints in cases involving bulk supply overlaps generally have alleged relevant markets much smaller than a whole PADD. An actual antitrust investigation would analyze in detail the economic options for bulk supply deliveries by refiners and other shippers on a terminal-by-terminal basis. Differing proximity to pipelines or localized pipeline capacity constraints may imply that some areas within a PADD have more limited supply sources than other areas within that PADD.

42 The incentive and ability of PADD III refiners to ship additional product into PADD I would also depend on transport costs and the availability of capacity to send more product by pipeline or by water.

43 The competitive significance of imports within certain parts of PADD I may vary depending on transport costs and the availability of capacity to send more product by pipeline or by water.

44 EIA, Annual Energy Outlook 2003, Table 13.

estimates for a five-state "Upper Midwest" area that is part of PADD II.[45] The HHI for Upper Midwest refinery capacity increased from 1,085 in 1985 to 1,732 in 2003.[46] The increases in the HHIs for refining capacity in both PADD II and the Upper Midwest resulted in part from the Marathon/Ashland joint venture (1997) and the BP/Amoco merger (1998). The closure of many small refineries in PADD II also played some role in the increase in concentration.[47]

The 1982 and 1989 Merger Reports described the Upper Midwest as a "possible" relevant geographic market for merger analysis.[48] However, those reports qualified this description because shipments of refined products from PADD III to PADD II were significant, and because two large pipelines (Texas Eastern and Explorer) directly connected PADD III refineries and the Upper Midwest. Since that time, shipments from PADD III to PADD II have continued to be significant.[49] Centennial, a new pipeline with a capacity of 210 MBD, provides another connection between PADD III refineries and the Upper Midwest. Explorer has also expanded significantly.[50] The fact that Explorer and Centennial ship into the Chicago area (the middle of the proposed Upper Midwest market) also makes it unlikely that refining capacity in the Upper Midwest could be defined as a relevant antitrust market. The FTC's Midwest Gasoline Price investigation further underscored the competitive significance of PADD III refineries in supplying PADD II.[51] Consequently, HHIs for PADD II or the Upper Midwest alone are likely to overstate significantly the level of concentration that is relevant to analysis of competition, assuming there are no pipeline or product specification constraints.

Given the evidence that PADD III refineries are competitive in the Midwest, a relevant geographic market defined to include both PADDs II and III may be appropriate (or, at minimum, the ability of PADD III refineries to supply PADD II must be considered in any competitive analysis of bulk supply within PADD II). Table 7-7 shows that, while concentration in an area consisting of PADD II and III has increased since 1985, the HHI is still in the unconcentrated range.

Differences between, on the one hand, refiner shares in PADD II or the Upper Midwest and, on the other hand, such shares in PADD III explain why concentration in the combined area is lower than in PADD II or the Upper Midwest alone. For example, BP and Marathon Ashland controlled roughly

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45 This is the same five-state area that the FTC looked at in the 2001 Midwest Gasoline Price Investigation.

46 The Upper Midwest HHI was 2,029 in 2001. The increase in 2001 was primarily due to the idling of Citgo's Lemont, Illinois refinery in 2001. That refinery was reopened in 2002, causing the HHI to fall to 1,844.

47 The number of refineries in PADD II fell from 44 on Jan. 1, 1986 to 26 on Jan. 1, 2004. *See* Table 7-2.

48 1982 Merger Report 179-81.

49 In 2003, 18.6% of light refined products consumed in PADD II originated in PADD III. *See* Table 7-6.

50 The 1982 Merger Report stated that Explorer had a capacity of 367 MBD into the Upper Midwest. Currently, Explorer has a capacity of 480 MBD into the Upper Midwest.

51 Midwest Gasoline Report at 9.

equal shares of about 49% of the refining capacity in the Upper Midwest in 2003. Any anticompetitive output restriction to increase bulk supply prices in the Upper Midwest would probably need to involve both of these firms. Refiners such as ExxonMobil and ConocoPhillips, which have refineries in PADD III, have much smaller capacity shares in the Upper Midwest and may find it profitable to divert product from their refineries in PADD III to the Upper Midwest should prices rise in the latter area. Important PADD III refiners with no Upper Midwest refinery assets, such as Valero, Chevron and Motiva, would have particularly strong incentives to ship more product into the Upper Midwest area in response to a price increase.

It is also appropriate to consider the competitive influence of PADD I refiners on PADD II. First, shipments from PADD I to PADD II accounted for 8% of PADD II LPP consumption in 2003.[52] Second, because PADD III refineries ship substantial volumes to both PADDs I and II, changes in PADD I conditions can affect the flow from PADD III to PADD II. For example, a price increase in PADD I could cause prices in PADD II to rise by causing PADD III refiners to divert shipments from PADD II to PADD I. Thus, the fact that PADDs I and II are common export markets for PADD III connects them more closely than is suggested solely by shipments from PADD I to PADD II. PADDs I, II, and III combined are unconcentrated, with an HHI of 789 in 2003.

PADD III refinery capacity concentration stood at an HHI of 1018 in 2003 (an increase of 419 since 1985). Much of this increase is attributable to combinations of PADD III refineries in the Exxon/Mobil, Motiva, BP/Amoco, Valero/UDS, Phillips/Tosco, and Conoco/Phillips transactions. Exxon/Mobil increased the PADD III HHI by about 125 points; the other transactions had smaller effects. The closure of several small refineries in PADD III also played some role in the concentration increase.

Concentration in PADD IV is also low. Table 7-7 shows that the PADD IV HHI was 944 in 2003. The HHI increased to 1,319 in 2002 because the 2002 capacity data reflect the Conoco/Phillips merger, but not the FTC-required divestiture of two refineries that followed in 2003. After accounting for these divestitures, the PADD IV HHI is 944, which is below the HHI level for 1985.

In PADD V, capacity concentration has been relatively low throughout the period 1985-2003; it now falls into the moderately concentrated range. The HHI fell from 1,248 in 1985 to 965 in 1990.[53] The HHI returned to

52 Some of these shipments may take place on Colonial pipeline spurs from Georgia (PADD I) to Tennessee (PADD II), and may not be product from a PADD I refiner.

53 This decline in concentration is attributable to the reduction in distillation capacity by Chevron, the leading PADD V refiner. Chevron had significant excess distillation capacity in its refineries. During this period, it was reducing distillation capacity and increasing downstream refining capacity to increase efficiency. Chevron stated that its U.S. distillation capacity utilization was 63% in 1985, while its downstream processes were utilized at 86%. *See* Chevron Corp., 1985 Form 10-K at 8. Chevron discussed an upgrade of its Richmond, California, refinery in 1991 that involved a decrease in distillation capacity. "Crude processing operations were

its 1985 level in 2003. Three mergers between 1996 and 2001 contributed to this increase: Tosco's acquisition of Unocal in 1997, the formation of the Equilon joint venture by Shell and Texaco in 1997, and Valero's acquisition of UDS in late 2001. Exxon's acquisition of Mobil in 1999 and the Chevron/Texaco merger in 2001, however, had no impact on PADD V distillation capacity concentration due to FTC-required refinery divestitures, which were primarily motivated by merger-created overlaps in the narrower market for CARB gasoline.

Tosco's acquisition of Unocal combined Unocal's 8.5% of PADD V capacity with Tosco's 7.9%, resulting in an increase in the HHI of 134 to a post-merger value of 1,166. Tosco later sold one of the three PADD V refineries it bought from Unocal to UDS in 2000.[54]

The increase in the distillation capacity HHI in PADD V as a result of the 1997 Shell/Texaco joint venture was only 78. As Table 7-9 shows, PADD V concentration would have been higher by nearly 90 points but for the FTC-mandated sale of a Shell refinery in Washington to Tesoro. Concerns in narrower geographic and product markets, including the market for CARB gasoline, motivated enforcement actions in Shell/Texaco.

Exxon and Mobil both had refineries in PADD V before their merger. The FTC order involving that merger required divestiture of the Exxon refinery, which was subsequently sold to Valero, a firm with no PADD V refining presence. Absent this divestiture requirement, the Exxon/Mobil merger would have increased PADD V distillation capacity concentration by only 37 points, from 1,257 to 1,294. However, the FTC analyzed this refinery merger primarily as a consolidation in CARB gasoline; for that product, concentration and concentration increases in the relevant market were higher, as noted in the discussion about California concentration trends.

Valero acquired UDS in 2001, but had to divest UDS's Northern California refinery under an FTC order. Otherwise, this merger would have combined Valero's 4.8% of PADD V distillation capacity with UDS's 7.8% and would have increased the HHI from 1,155 to 1,231. The sale of this refinery to Tesoro is reflected in the 2002 data, which show the PADD V HHI increasing to 1,246. The HHI increased over the post-merger level because Tesoro already had a share of PADD V's distillation capacity, with refineries in Washington, Alaska, and Hawaii, but not California. This enforcement outcome is explained by the fact that, as in Exxon/Mobil, the FTC analyzed this refinery combination primarily in a CARB market. There was little overlap between the California refinery purchased by Tesoro and that firm's existing refineries in PADD V.[55]

streamlined at the Richmond, California, refinery into one modern crude unit. The resulting debottlenecking and reduction in capacity to 220,000 barrels per day, coupled with the installation of an expanded conversion unit, is expected to increase energy efficiency and reduce operating cost." Chevron Corp., 1991 Form 10-K at 25.

[54] This refinery was sold to Tesoro in 2002 in settling the FTC's investigation of the Valero/UDS acquisition.

[55] *See* Valero/UDS, Concurring Statement of Commissioner Mozelle W. Thompson, Valero Energy Corporation's Petition to Approve a Divestiture (Apr.

Refinery mergers in California have received close scrutiny, particularly since CARB gasoline standards, which first went into effect in 1992, have become progressively more stringent. Only a limited number of refineries outside of California produce CARB gasoline. Unlike other parts of the country, California lacks pipeline connections with other major refining centers in the United States. As a result, the ability of refiners and bulk suppliers outside California to constrain prices in California is more limited. Distillation capacity shares in California, however, are an imperfect measure of CARB market concentration because not all crude distillation capacity in California can be used to make CARB, and some capacity outside California is used to make CARB that can be sold in California.

Between 1985 and 1990 (prior to the introduction of CARB), the California refinery capacity HHI fell from 1,434 to 1,184. This decline was largely due to Chevron reducing its distillation capacity, as noted above. The California capacity HHI in 2003 – 1,475 – represented an increase to only slightly above its 1985 level, due primarily to the Tosco/Unocal and Shell/Texaco transactions.[56] Before the merger between Tosco and Unocal, Unocal had 13.2% and Tosco had 7.4% of California capacity. This merger caused the California HHI to increase from 1,335 to 1,530. The Shell/Texaco deal also had an impact on California capacity concentration. In 1996, the year prior to the joint venture, Shell and Texaco respectively had 8.4% and 6.8% of California refining capacity. The combination of Shell and Texaco increased the HHI for California refining capacity by 114 points to a post-merger level of 1,644. As mentioned above, the FTC analyzed the Shell/Texaco transaction with regard to the CARB market. The impact of the transaction on this market included Shell's Anacortes, WA refinery, which was a CARB producer. According to the FTC, the Shell/Texaco joint venture would have increased the HHI in a CARB market by 154 points to a post-merger level of 1,635. The FTC required divestiture of Shell's Anacortes refinery, which also alleviated competitive concerns in gasoline and jet fuel in the Puget Sound and Pacific Northwest.[57]

Because of FTC divestiture orders, concentration has not increased in California since 1999, despite three major mergers directly involving California refineries.[58] As shown in Table 7-9, the Exxon/Mobil merger would have increased concentration in California refining from 1,636 to 1,728. The FTC's complaint in Exxon/Mobil alleged that the merger would increase concentration in *CARB capacity* – a more appropriate basis for concentration in the relevant market – by 171 points to 1,699. Exxon sold its Benicia refinery to

26, 2002). The only meaningful overlap existed because Tesoro produced some CARB gasoline at its Washington State refinery. However, the amount produced was small and thus the impact on competition in the CARB market was not significant.

[56] The HHI of 1,654 in 2001 is higher than that for 2002 because the 2001 data combine Valero and UDS and do not reflect the refinery divestiture to Tesoro in 2002.

[57] *See* Table 2-5 for details on FTC enforcement action in Shell/Texaco.

[58] In fact, HHIs have decreased as a result of Tosco's sale of its Avon refinery to UDS.

Valero (a new entrant in California) to resolve this concern.

In the Valero/UDS merger, Valero held 7.6% of California refining capacity and UDS had 12.2%. This transaction would have increased concentration in California refining capacity by 185 points, from 1,469 to 1,654. The sale of UDS's San Francisco area refinery (with an 8.4% share of California capacity) to Tesoro (a firm without a California refinery) lowered the California HHI to 1,463, slightly below pre-merger levels. The FTC focused again on a CARB market in this investigation.

Finally, the settlement in Chevron/Texaco prevented the combination of Chevron's 24.5% of California refining with Texaco's interest in Equilon, which had a 16.4% share of California refining. This combination would have increased the HHI by as many as 804 points to 2,273. If the Exxon/Mobil and Chevron/Texaco mergers had been consummated as they were originally proposed, the HHI would have increased to about 2,377, rather than the present 1,475.[59] Table 7-9 summarizes the effects of FTC enforcement actions in preventing distillation capacity concentration increases in California and in PADD V as a whole.

VI. Entry into Refining

The 1982 Merger Report discussed several impediments and barriers to entry into refining, including high sunk costs and environmental regulations. These entry-deterring factors have become more formidable since the 1980s, as refineries have become more capital-intensive and environmental regulations have become more restrictive. Indeed, *de novo* entry into U.S. refining is widely regarded as very unlikely.[60] No new refinery still in operation has been built in the United States since 1976. Historically low returns on refining, the declining availability of domestic crude, and the high costs of meeting environmental standards all discourage *de novo* entry. Future supply increments are expected to come from expansion of existing refineries and increased reliance on imported refined products rather than the opening of new refineries.

More likely is entry by existing refineries into relevant products that they do not presently produce. Refineries not presently capable of producing certain fuel specifications might find it profitable to do so if presented with sufficient sales opportunities. For example, Valero has expanded the downstream processes at its Corpus Christi refinery for increased production of clean fuels, including CARB.[61] Similarly, a refiner not presently supplying a particular geographic area might choose to reallocate product to that area in response to a relative price increase. This may be an entry question

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[59] Absent FTC actions, Chevron would have held its 25% share of California refining plus an interest in Equilon's 16% share. Exxon would hold 15% of capacity rather than its present 7.5%. The Valero/UDS transaction is not relevant here because, had Exxon been allowed to keep the Benicia refinery, Valero's acquisition of UDS would not have created a horizontal overlap in California.

[60] EIA, *Annual Energy Outlook 2003*, 83.

[61] Valero Energy Corp., Form 10-K for the years 1998-2001.

– rather than an issue of geographic market definition – if entry into a geographic area entails some substantial time impediments or sunk costs (for instance, a refiner might need to obtain downstream marketing assets or terminal access to be considered a significant competitor).

The 1982 Merger Report identified access to crude oil as an impediment to refinery entry or expansion by small refiners. That report observed that an entrant could not safely rely on purchases of foreign crude oil in light of the "vagaries of international politics" or the "threat of changes in U.S. policies towards imports." The Report also suggested that entrants and small refiners might be at a competitive disadvantage compared to larger petroleum firms because the entrants and small refiners might be unable to obtain sufficient quantities of crude from foreign producers. The importance of crude supply was also underscored by the extensive integration of top refiners into crude oil exploration and production.[62]

There are indications that access to crude oil has become less of an entry or expansion impediment than in the 1980s. Certainly any advantage associated with integration between refining and crude oil appears to have declined. In the past, the top refiners had significant crude oil product and supply assets.[63] As late as 1990, EIA reported that the U.S. majors, all of which were vertically integrated into both crude oil production and refining, held 72% of U.S. crude distillation capacity, while independent refiners, which did not have upstream assets, held 8%. By October 1998, the U.S. majors' share of refining capacity had fallen to 54%, and independents' share had increased to 23%.[64] The independents' share fell somewhat after Phillips acquired Tosco, but at least four large, non-integrated refiners remain – including Valero/UDS, Sunoco, Tesoro, and Premcor. At the end of 2003, these four non-integrated refiners accounted for 19.6% of U.S. refining capacity.

There is additional evidence that U.S. refiners have become less vertically integrated. EIA's FRS companies have been purchasing a greater share of the crude oil used by their domestic refineries, as shown in Figure 7-2. This trend began around 1980 and continued through 1997. Starting in 1998, the FRS companies included a number of unintegrated refiners, such as Premcor Refining Group, Tesoro Petroleum, The

[62] 1982 Merger Report 189-91. Despite incentives for vertical integration, firms varied substantially in their degree of integration. For example, in 1974, 7 of 27 listed U.S. companies had more crude production than refinery runs and another 6 were between 80% and 100% self-sufficient in crude, while the remaining 14 were less than 80% self-sufficient. *See* David J. Teece, *Vertical Integration in the U.S. Oil Industry*, in VERTICAL INTEGRATION IN THE OIL INDUSTRY 117, Table 1-B (Edward J. Mitchell, ed.) (1976). The degree of self-sufficiency is defined as a firm's net crude production divided by refinery crude runs. Although this is an imperfect measure of self-sufficiency (since a firm need not use crude it produces in its own refineries), the measure has been used in other studies and reports, including Federal Trade Commission, *Preliminary Federal Trade Commission Staff Report on Its Investigation of the Petroleum Industry* (July 1973).

[63] EIA did not categorize any petroleum companies as non-integrated refiners in 1980 or 1990, but in 2000 it listed 10 non-integrated refiners. EIA, *Performance Profiles of Major Energy Producers 2000*, 74.

[64] EIA, *The U.S. Petroleum Refining and Gasoline Marketing Industry, available at* http://www.eia.doe.gov/emeu/finance/usi&to/downstream/index.html.

Coastal Corporation, Ultramar Diamond Shamrock, and Valero Energy. This change makes these data difficult to compare with the prior years. Greater reliance on market purchases of crude oil by the FRS companies suggests that the advantages of vertical integration between refining and crude production have declined since the 1970s. Acquiring crude oil on the spot market or through futures contracts may have become a more attractive option relative to using captive production. Factors apparently favoring increased reliance on crude oil markets in supplying refinery needs include refineries' increased technical ability to switch economically among crude oil types, better transportation (particularly for marine shipments), and the general maturing and deepening of both the physical and futures markets for crude oil.

Another indication that refiners see less need to own crude oil reserves for their own use is that crude oil self-sufficiency among some of the largest integrated refiners has been declining generally since the 1970s. Tables 7-10 and 7-11 show self-sufficiency ratios for selected major integrated refiners.[65]

As the two tables show, the large integrated refiners generally reduced their crude production relative to refinery runs. Much of this decline occurred between 1970 and 1980. For domestic crude and refining, this is perhaps not surprising, as overall domestic crude production has fallen. Both domestically and worldwide, only Phillips increased its self-sufficiency ratio between 1970 and 2000, in large part through its acquisition of ARCO's Alaskan assets pursuant to the FTC consent order in the BP/ARCO matter. Firms varied widely in their crude oil self-sufficiently in every period.

Organizational changes at vertically-integrated petroleum companies are also consistent with these trends in reduced crude oil self-sufficiency, as a recent Rand study reports:

> Operations within firms also have become more autonomous. In the past, refinery operations in vertically integrated oil companies commonly were managed as a means to "monetize" the crude oil discoveries and production from upstream operations via transfer pricing and other mechanisms. That is, downstream refining operations often were subsidized or financed by the upstream. Today, U.S. refining operations are generally managed as stand-alone business units accountable for their own bottom lines. Among the vertically integrated firms, the upstream and downstream portions are run somewhat independently: Their refineries, for example, often process crude purchased on the open market.[66]

65 Ideally, a measure of self-sufficiency would reflect the fraction of a firm's crude production that the firm uses in its own refineries. Using overall crude production overstates a firm's self-sufficiency to the extent that some of the crude production is sold or exchanged with other refiners. This problem is likely to be greater for worldwide production and refinery runs than for the equivalent U.S. figures. However, the figures in Tables 7-10 and 7-11 are likely to provide qualitative information on industry trends.

66 Rand Report at 14.

Table 7-1 – Number of Operable U.S. Refineries, Total Capacity, Average Capacity and Utilization 1949-2004

Year	Number	Total Capacity (mmbd)	Average Refinery Capacity (mbd)	Utilization (%)
1949	336	6.23	18.5	89.2
1954	308	7.98	25.9	88.8
1959	313	9.76	31.2	85.2
1964	298	10.31	34.6	89.6
1969	279	11.7	41.9	94.8
1973	268	13.64	50.9	93.9
1974	273	14.36	52.6	86.6
1975	279	14.96	53.6	85.5
1976	276	15.24	55.2	87.8
1977	282	16.40	58.2	89.6
1978	296	17.05	57.6	87.4
1979	308	17.44	56.6	84.4
1980	319	17.99	56.4	75.4
1981	324	18.62	57.5	68.6
1982	301	17.89	59.4	69.9
1983	258	16.86	65.3	71.7
1984	247	16.14	65.3	76.2
1985	223	15.66	70.2	77.6
1986	216	15.46	71.6	82.9
1987	219	15.57	71.1	83.1
1988	213	15.92	74.7	84.7
1989	204	15.65	76.7	86.6
1990	205	15.57	76.0	87.1
1991	202	15.68	77.6	86.0
1992	199	15.70	78.9	87.9
1993	187	15.12	80.9	91.5
1994	179	15.03	84.0	92.6
1995	175	15.43	88.2	92.0
1996	170	15.33	90.2	94.1
1997	164	15.45	94.2	95.2
1998	163	15.71	96.4	95.6
1999	159	16.26	102.3	92.6
2000	158	16.51	104.5	92.6
2001	155	16.60	107.1	92.6
2002	153	16.79	109.7	90.3
2003	149	16.76	112.5	NA
2004	149	16.89	113.4	NA

Source: 1949-2002 data: *Refinery Capacity Utilization, 1949-2002*. EIA, *Annual Energy Review 2002*, Table 5.9. 2003 and 2004 data: *EIA Petroleum Supply Annual* (2002, 2003), Table 36. Total capacity is in million barrels per calendar day on January 1.

Table 7-2 – Number of Operable Refineries and Refining Capacity by PADD 1986-2004

Year	Refinery Data	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
1986	Number	26	44	75	20	51	216
	Capacity	1.45	3.30	7.11	0.53	3.07	15.46
	% of U.S. Capacity	9.4	21.4	46.0	3.4	19.9	
1991	Number	22	40	72	18	50	202
	Capacity	1.49	3.33	7.21	0.56	3.09	15.68
	% of U.S. Capacity	9.5	21.2	46.0	3.5	19.7	
1995	Number	18	34	65	15	43	175
	Capacity	1.57	3.45	7.01	0.51	2.90	15.4
	% of U.S. Capacity	10.2	22.3	45.4	3.3	18.8	
1997	Number	17	29	62	15	41	164
	Capacity	1.46	3.44	7.09	0.52	2.93	15.45
	% of U.S. Capacity	9.5	22.3	45.9	3.4	19.0	
2001	Number	16	28	56	16	39	155
	Capacity	1.70	3.64	7.59	0.55	3.12	16.60
	% of U.S. Capacity	10.2	21.9	45.7	3.3	18.8	
2004	Number	16	26	55	16	36	149
	Capacity	1.74	3.53	7.88	0.58	3.16	16.89
	% of U.S. Capacity	10.2	20.9	46.7	3.4	18.7	

Source: EIA, *Petroleum Supply Annual*, Table 29 (1985), Table 36 (1990, 1994, 1996, 2000, 2003). Capacity is in millions of barrels per calendar day on January 1.

Table 7-3 – Atmospheric Distillation and Downstream Capacity of Operable U.S. Refineries 1985-2003, End of Year (1000's bbls per Stream Day)

Year	Atmospheric Distillation	Vacuum Distillation	Thermal Cracking	Catalytic Cracking	Catalytic Hydro-Cracking	Catalytic Reforming	Hydro-Treating
1985	16,346	6,892	1,880	5,677	1,125	3,744	8,791
1990	16,557	7,276	2,158	5,863	1,308	3,926	9,676
1996	16,287	7,349	2,050	5,750	1,388	3,727	11,041
2003	17,815	7,964	2,435	6,185	1,602	3,812	13,501
% Change 1985 to 2003	9.0	15.6	29.5	8.9	42.4	1.8	53.6

Source: EIA, *Petroleum Supply Annual*, Table 41 (2003).

Table 7-4 – Size Distribution of Operating Refineries 1986 and 2004

Operating Distillation Capacity (barrels per day)	1986		2004	
	Number of Refineries	Percent of Capacity	Number of Refineries	Percent of Capacity
1-10,000	41	1.8	14	0.5
10,001-25,000	25	2.9	19	2.0
25,001-50,000	40	10.6	12	2.9
50,001-100,000	38	19.2	38	16.4
100,001-200,000	27	26.2	30	27.8
Greater than 200,000	19	39.4	31	53.7
Total[1]	190		144	

Source: EIA, *Petroleum Supply Annual* (1985, 2003). Capacity as at January 1 of year shown.

Note: [1]Excludes refineries that were classified as "operable" by EIA, but listed with zero operating capacity.

Table 7-5 – Inter-PADD Shipments and Imports – Finished Light Refined Petroleum Products[1]
1985
(1,000's bbls)

Product's Origin	PADD I	PADD II	PADD III	PADD IV	PADD V	United States
Refinery Production	356,560	893,034	1,740,038	140,133	627,459	3,757,224
Other Production [2]	0	0	598	3	0	601
Imports	184,013	7,077	8,540	2,155	24,450	226,235
Exports	660	779	16,874	6	14,633	32,952
Net Imports	183,353	6,298	-8,334	2,149	9,817	193,283
Receipts from other PADDS						
PADD I	N/A	102,459	424	0	0	102,883
PADD II	20,131	N/A	26,703	25,047	0	71,881
PADD III	864,184	222,644	N/A	0	19,177	1,106,005
PADD IV	0	10,522	0	N/A	14,047	24,569
PADD V	199	0	0	0	N/A	199
Receipts from other PADDS	884,514	335,625	27,127	25,047	33,224	1,305,537
Deliveries to other PADDS	102,883	71,881	1,106,005	24,569	199	1,305,537
Net Receipts from other PADDS	781,631	263,744	-1,078,878	478	33,025	0
Stock Change [3]	-15,198	-19,669	6,238	-1,635	-3,519	-33,783
Product Supply [4]	1,336,742	1,182,745	647,186	144,398	673,820	3,984,891
Percentage of Product Supply						
Refinery Production	26.7	75.5	268.9	97.0	93.1	94.3
Other Production	0.0	0.0	0.1	0.0	0.0	0.0
Net Imports	13.7	0.5	-1.3	1.5	1.5	4.9
Net Receipts from Other PADDS	58.5	22.3	-166.7	0.3	4.9	N/A
Stock Change	-1.1	-1.7	1.0	-1.1	-0.5	-0.8
From Outside PADD	72.2	22.8	-168.0	1.8	6.4	4.9

Source: Receipts from other PADDs: EIA, *Petroleum Supply Annual*, Table 20 (1985); Other Data: EIA, *Petroleum Supply Annual*, Tables 4, 5, 6, 7, 8 (for PADDs I, II, III, IV, V respectively) (1985).
Note:

[1] Light refined products are finished motor gasoline, jet fuel and distillate fuel oil.
[2] Other production is production of hydrocarbons/oxygenates and motor gasoline blending components, and fuel ethanol blended into finished motor gasoline.
[3] A positive stock change denotes an increase in stocks; a negative stock change denotes an decrease in stocks.
[4] Product supply equals refinery production plus other production plus net imports plus net receipts from other PADDs minus stock change.

Table 7-6 – Inter-PADD Shipments and Imports – Finished Light Refined Petroleum Products[1] 2003 (1000's bbls)

	PADD					
Product's Origin	I	II	III	IV	V	United States
Refinery Production	584,906	1,034,664	2,221,130	170,819	875,707	4,887,226
Other Production [2]	27,800	81,557	12,154	-2,970	-6,529	112,012
Imports	314752	3,572	3,620	3,236	25,329	350,509
Exports	2,783	2,365	67,034	3	19,998	92,183
Net Imports	311,969	1,207	-63,414	3,233	5,331	258,326
Receipts from other PADDS						
PADD I	N/A	113,226	0	0	0	113,226
PADD II	11,609	N/A	15,777	19,665	0	47,051
PADD III	1,105,667	272,650	N/A	16,423	26,587	1,421,327
PADD IV	0	13,109	0	N/A	8,955	22,064
PADD V	785	0	50	0	N/A	835
Receipts from other PADDS	1,118,061	398,985	15,827	36,088	35,542	1,542,615
Deliveries to other PADDS	113,226	47,051	1,421,327	22,064	835	1,542,615
Net Receipts from other PADDS	1,004,835	351,934	-1,405,500	14,024	34,707	0
Stock Change [3]	-1,560	4,174	-5,794	-899	-8,877	-12,956
Product Supply [4]	1,931,070	1,465,188	770,164	186,005	918,093	5,270,520
Percentage of Product Supply						
Refinery Production	30.3	70.6	288.4	91.8	95.4	92.7
Other Production	1.4	5.6	1.6	-1.6	-0.7	2.1
Net Imports	16.2	0.1	-8.2	1.7	0.6	4.9
Net Receipts from Other PADDS	52.0	24.0	-182.5	7.5	3.8	0
Stock Change	0.1	-0.3	0.7	0.5	1.0	0.2
From Outside PADD	68.2	24.1	-190.7	9.2	4.4	4.9

Source: Receipts from other PADDs: EIA, *Petroleum Supply Annual*, Table 32 (2003); Other data: EIA, *Petroleum Supply Annual*, Tables 4, 6, 8, 10, 12 (for PADDs I, II, III, IV, V respectively) (2003).

Note:

[1] Light refined products are finished motor gasoline, jet fuel and distillate fuel oil.
[2] Other production is production of hydrocarbons/oxygenates and motor gasoline blending components, and fuel ethanol blended into finished motor gasoline.
[3] A positive stock change denotes an increase in stocks; a negative stock change denotes an decrease in stocks. Distillate stocks in the Northeast Heating Oil Reserve are not included.

[4] Product supply equals refinery production plus other production plus net imports plus net receipts from other PADDs minus stock change.

Table 7-7 – Regional Refining Concentration Trends

PADD	1969	1979	1981	1985	1990	1996	2000	2001	2002	2003
U.S.										
4-Firm (%)				34.4	31.4	27.3	40.2	42.5	45.4	44.4
8-Firm (%)				54.6	52.2	48.4	61.6	67.2	70.0	69.4
HHI				493	437	412	611	686	743	728
PADD I										
4-Firm (%)				50.9	59.2	75.5	80.7	80.9	80.9	76.7
8-Firm (%)				83.7	88.7	93.8	99.0	99.0	99.0	97.9
HHI				995	1,225	2,001	2,158	2,119	2,126	1,943
PADD II										
4-Firm (%)	38.3	37.4	40.1	41.4	39.3	40.9	50.9	51.1	55.3	57.1
8-Firm (%)	59.7	60.0	60.8	64.4	65.0	67.3	75.6	76.6	78.2	82.6
HHI				681	675	721	961	976	1,019	1,063
PADD III										
4-Firm (%)	44.0	36.2	36.8	39.2	36.3	35.1	48.4	53.6	55.1	56.3
8-Firm (%)	64.8	54.5	55.6	58.1	58.5	58.1	66.5	76.3	79.2	78.8
HHI				599	578	576	851	974	965	1,018
PADD IV										
4-Firm (%)	53.5	48.0	53.4	57.3	55.8	55.0	58.1	57.2	60.1	46.1
8-Firm (%)	81.7	75.3	80.4	82.7	83.6	84.4	86.9	86.4	90.0	81.2
HHI				1,093	1,080	1,129	1,179	1,176	1,319	944
PADD V										
4-Firm (%)	66.5	54.4	55.9	58.0	53.8	54.0	60.2	61.2	62.6	62.4
8-Firm (%)	95.2	76.5	79.6	79.6	74.2	79.5	86.9	92.7	92.7	92.7
HHI				1,248	965	1,034	1,148	1,231	1,246	1,246
Upper Midwest[1]										
4-Firm (%)	47.7	48.7	54.1	56.5	54.7	57.4	75.6	81.0	77.1	75.2
8-Firm (%)	74.4	75.5	81.6	86.9	87.9	90.7	99.8	100.0	99.7	99.8
HHI				1,085	1,102	1,177	1,756	2,029	1,844	1,732
California										
4-Firm (%)				60.2	58.9	61.4	68.7	73.8	66.4	66.2
8-Firm (%)				81.5	82.5	89.6	95.1	97.5	96.3	96.3
HHI				1,434	1,184	1,335	1,481	1,654	1,459	1,475
PADDs I & III										
4-Firm (%)	40.9	35.0	35.1	38.4	36.7	32.2	44.6	51.6	54.0	54.6
8-Firm (%)	62.3	55.0	54.7	57.3	57.2	55.3	65.3	74.4	76.2	76.1
HHI				573	561	514	741	876	922	919
PADDs II & III										
4-Firm (%)				33.4	30.7	31.7	42.5	43.5	46.4	46.2
8-Firm (%)				53.3	56.5	53.0	64.9	70.4	74.6	75.6
HHI				469	455	485	681	754	812	826
PADDs I, II & III										
4-Firm (%)	35.2	30.7	29.5	32.8	30.2	29.8	39.4	42.9	45.5	45.9
8-Firm (%)	58.0	49.2	47.8	54.1	53.6	51.4	63.5	69.6	73.0	73.1
HHI				469	460	460	638	723	783	789

Source: CR4 and CR8 numbers: 1969-1981: 1989 Merger Report, 96, Table 26; 1985-2003: derived from EIA, *Petroleum Supply Annual*, Table 38 (1985, 1990, 1996, 2000, 2001, 2002, 2003). Capacities are crude oil distillation capacity measured per calendar day at the end of the year.

Note:

[1] The Upper Midwest consists of Illinois, Indiana, Kentucky, Michigan and Ohio.

Table 7-8 – U.S. Distillation Capacity Shares of Refiners Affected by Selected Mergers 1996-2003

Present Company	Previous Companies	1996 (%)	2000 (%)	2003 (%)
Exxon/Mobil	Exxon	6.7	11.4	11.5
	Mobil	6.3		
BP	BP	3.7	10.2	9.0
	Amoco	6.7		
	ARCO	3.2		
Shell	Shell	7.6	10.7	10.7
	Texaco/Star	6.3		
ConocoPhillips	Phillips	2.3	2.4	13.1
	Tosco	3.1	8.0	
	Unocal	1.6		
	Conoco	3.2	3.3	
Marathon-Ashland Petroleum	Marathon	3.8	5.7	5.6
	Ashland	2.3		
Valero	Valero		3.8	8.3
	UDS		3.3	

Source: EIA, *Petroleum Supply Annual*, Table 38 (1996, 2000, 2003).

Table 7-9 – FTC Actions in California and PADD V that Prevented or Limited HHI Increases

California		PADD V	
Exxon/Mobil		Shell/Texaco (Equilon)	
Pre-merger HHI (1998)	1,636	Pre-merger HHI (1997)	1,034
Exxon 6.8%, Mobil 6.8%		Shell 9.2%, Texaco 9.0%, Tesoro 2.5%	
HHI if no Remedy	1,728	HHI if no remedy	1,200
Post-remedy HHI	1,636	Post-remedy HHI	1,112
		Equilon 14.5%, Tesoro 6.3%	
Valero/UDS		Exxon/Mobil	
Pre-merger HHI (2001)	1,469	Pre-merger HHI (1998)	1,257
Valero 7.6%, UDS 12.2%		Exxon 4.3%, Mobil 4.3%	
HHI if no remedy	1,654	HHI if no remedy	1,294
Post-remedy HHI	1,463	Post-remedy HHI	1,257
Tesoro 8.4%, Valero 11.4%			
Chevron/Texaco		Chevron/Texaco	
Pre-merger HHI (2001)	1,469	Pre-merger HHI (2001)	1,231
Chevron 24.5%, Texaco (Equilon) 16.4%		Chevron 17.4%, Texaco (Equilon) 15.0%	
HHI if no remedy	2,273	HHI if no remedy	1,753
Post-remedy HHI	1,469	Post-remedy HHI	1,231

Source: Concentration estimates are based on refining capacity data in EIA, *Petroleum Supply Annual*, Table 38.

Table 7-10 – Self-Sufficiency Ratios for Selected Firms - Domestic 1970-2000

Company	1970 (%)	1980 (%)	1990 (%)	1996 (%)	2000 (%)
BP/Sohio[1]	8	N.A.	105	105	45
Chevron	77	32	33	36	33
Exxon[2]	111	63	74	59	39
Mobil	69	50	44	28	N.A.
Phillips[3]	N.A.	N.A.	21	22	54
Shell[4]	N.A.	N.A.	32	46	49
Texaco	98	52	67	54	68

Sources: Derived from firms' *Form 10-K*'s and *Moody's Industrial Manual* (annual). The ratio is defined as a firm's net domestic crude production divided by domestic refinery crude runs.

Notes:

[1] British Petroleum acquired an interest in Standard Oil of Ohio (Sohio) in 1969 and acquired the remaining shares of Sohio in 1987. Until Sohio began shipping Alaskan crude oil in the 1970s, the company had little crude production. BP's sharp drop in domestic self-sufficiency between 1996 and 2000 was driven by two-transactions: (1) its acquisition of relatively crude-short Amoco in 1999 and (2) the FTC-mandated divestiture of ARCO's Alaskan crude production to Phillips as a condition of BP's acquisition of ARCO, which then primarily left refining assets remaining.

[2] Exxon acquired Mobil in 1999, so the decrease in 2000 over 1996 reflects Mobil's lower self-sufficiency ratio.

[3] Phillips acquired ARCO's Alaskan assets in 2000, so the increase in self-sufficiency for that year reflects this purchase of substantial crude oil production. Data on Phillips' domestic refinery runs for 1970 and 1980 were not available, although estimates from the *National Petroleum News Factbook* in those years reports ratios of 51% and 49%.

[4] Shell and Texaco contributed their U.S. refining assets to the Equilon and Motiva joint ventures in 1998. The self-sufficiency ratios for the year 2000 reflect each parent company's share of the joint venture. Data for 1970 and 1980 were not available, although estimates from the *National Petroleum News Factbook* annual issue in those years reports ratios of 67% and 58%.

Table 7-11 – Self-Sufficiency Ratios for Selected Firms – Worldwide 1970-2000

Company	1970 (%)	1980 (%)	1990 (%)	1996 (%)	2000 (%)
BP	N.A.	72	68	71	66
Chevron	147	58	49	70	85
Exxon	103	33	52	43	45
Mobil	91	163	44	40	N.A.
Phillips	84	172	49	71	96
Shell	N.A.	N.A.	55	58	78
Texaco	174	131	58	53	61

Sources: Derived from firms' *Form 10-K*'s and *Moody's Industrial Manual* (annual). The ratio is defined as a firm's net worldwide crude production divided by its worldwide refinery crude runs.

Chapter 8

Structural Change in Bulk Transport of Refined Petroleum Products

Many regions of the United States lack local refineries or have local refinery capacity insufficient to meet demand. In such regions, bulk supplies of refined petroleum products are transported from more distant refining centers, usually via pipeline but sometimes by water. As a result, the cost and availability of refined petroleum product transport can have important implications for competition in bulk supply markets and for the potential effects of a merger on this competition.

This chapter discusses structural trends in bulk transport of refined petroleum products, including the effects of mergers on the level of national concentration of refined product pipelines. Section I describes the various methods of bulk transportation of refined products and trends in such shipments. Relevant markets in which to analyze competition for bulk transport are discussed in Section II. Section III provides information on ownership concentration of refined product pipelines. Entry conditions are discussed in Section IV. Finally, Section V discusses FTC enforcement actions involving refined product pipelines.

I. Bulk Transport of Refined Products

Refined products are generally shipped in bulk from refineries to storage terminals, from which they are subsequently distributed by truck to local gasoline stations.[1] These terminals are often located a considerable distance from the refineries. Pipelines and water (tankers and barges) are the principal means of bulk shipment to product terminals.

Imports of refined products from outside the United States were discussed in Chapter 7.[2] Most of these imports enter the United States by tanker.[3] Overall, the market for refined product tankers, like the market for crude oil tankers, is unconcentrated and highly competitive. Although major oil companies own some of the product tankers that are used for imports, petroleum mergers of the last two decades have not raised competitive concerns relating to product tankers, and no FTC petroleum merger enforcement

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1 Most refineries also dispense smaller quantities of refined products into trucks at refinery racks for local wholesale and retail distribution.

2 *See* Tables 7-5 and 7-6.

3 Some product imports from Canada are by pipeline. In 2002, 22% of product imports to the United States were from Canada. *See* EIA, *Petroleum Supply Annual 2002*, Table 21.

action has alleged an anticompetitive effect involving product tankers.[4]

Pipelines are the leading method used for bulk transport of refined products within the United States; transportation by water is also important. Table 8-1 details the mode of shipment of refined products within the United States. While total ton-miles of refined product shipments within the United States declined from 1979 to 2001, shipments by pipeline increased from 236 billion ton-miles in 1979 to 299 billion ton-miles in 2001. Shipments by water fell from 257 billion ton-miles in 1979 to 146 billion ton-miles in 2001.[5] The share of ton-miles accounted for by pipelines increased from 44% in 1979 to 61% in 2001, while the share accounted for by water shipments declined from 48% to 30%. Trucks (primarily for short hauls of small quantities from terminals to wholesale and retail distribution points) and railroads account for small shares of ton-miles. Truck and rail shares changed very little over the period.

As discussed in Chapter 7, inter-PADD shipments of refined products are large.[6] Pipelines accounted for 82% of inter-PADD shipments in 2002.[7] While pipelines are the primary mode of inter-PADD and intra-PADD bulk shipments, water-borne carriage is also important in some instances. For example, although Arizona and Washington receive some pipeline shipments from PADDs III and IV, respectively, most of PADD V's relatively small imports from other PADDs arrive by tanker from PADD III. Pipeline supply of heating oil to the Northeast from PADD III may often be supplemented during winter months by product tankers carrying heating oil from the Gulf Coast to the New York Harbor area. New England has no refineries and no connections to the major pipelines that deliver refined products from the Gulf to other parts of PADD I and is heavily dependent on barge shipments from the New York Harbor area.

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4 In addition to tankers carrying imports into the United States, some petroleum companies own barges and tankers used for domestic transport of refined petroleum products. During the period covered by this report, petroleum mergers have not raised competitive concerns arising from changes in ownership or control of these barges and tankers used in domestic traffic.

As required for crude oil, the Jones Act requires that refined products moved from one United States destination to another be shipped on a domestically flagged vessel. As of March 2002, the United States-flag product tanker fleet had 64 ships, a number that is expected to fall over time due to forced retirement under the Oil Pollution Act of 1990. *See* Drew Laughlin, *Marine Product Tanker Fundamentals, Economics and Outlook* 3, 7-8 (Mar. 2002) (report prepared for the California Energy Commission). As discussed in Chapter 6, the FTC alleged anticompetitive effects in the market for Jones Act-compliant vessels for the transport of ANS crude oil in the BP/ARCO matter. To date, similar competitive concerns from mergers involving Jones Act product tankers have not arisen.

5 The large decline in water shipments between 1979 and 2001 is at least partly a result of the large decline in use of residual fuel oil (denser and heavier than distillate oil, and often used in manufacturing for heat and power), which is shipped by water. Use of residual fuel oil in the United States fell by more than 70%, from 2.83 MMBD in 1979 to 0.81 MMBD in 2001. EIA, *Petroleum Supply Annual 2002*, Table S6. *See also* EIA, *Petroleum Supply Annual 1990*, Table S6. The steepest drops in both water shipments of refined products and consumption of residual fuel oil occurred between 1979 and 1983.

6 *See* Tables 7-5 and 7-6.

7 EIA, *Petroleum Supply Annual 2002*, Tables 32-33.

II. Relevant Antitrust Markets for Bulk Transport of Refined Petroleum Products

Petroleum mergers may raise concerns relating to ownership of refined petroleum product pipelines. Concerns may arise when a transaction would combine the ownership of a refinery and a pipeline that supply the same market. In these cases, the relevant product markets are similar to the markets for bulk supply of refined products that are used to assess the competitive effects of mergers between refineries.[8] Antitrust concerns may also arise when a transaction would combine ownership shares in two competing refined product pipelines (or, in some cases, shares of one pipeline). In cases purely involving pipeline overlaps, markets may be defined for either origin or destination areas, as for crude oil pipelines.[9] Also as with crude oil pipelines, joint ventures and regulation can be important to competitive analyses relating to refined product pipelines.

III. National Concentration of Refined Petroleum Product Pipelines

National-level industry concentration for refined product pipelines can be estimated from the OGJ pipeline survey.[10] The OGJ survey identifies more than 70 companies with pipelines that carried refined products in the United States in 2002.[11] Table 8-2 lists the top product pipeline companies, ranked by barrel-miles shipped, in 1985, 1990, 1995, and 2001.[12] The Colonial pipeline, which transports products from PADD III to PADD I, is the nation's largest product pipeline company; by barrel-miles, Colonial is almost five times the size of the next largest carrier. Other important product pipelines are Plantation (which also transports product from PADD III to PADD I) and the Explorer, MidAmerica, and TEPPCO systems (all of which transport product from PADD III to PADD II). Between 1985 and 2001, the share of the top five refined product pipeline companies fell slightly, from 65.6% of barrel-miles in 1985 to 64.2% in 2001.

Many of the pipeline companies listed in Table 8-2 are joint ventures. For example, Colonial and Explorer each had eight owners in 2001, while Explorer currently has seven and Colonial has five.[13] To assess industry concentration based on parent ownership, ownership shares for each pipeline company were calculated and

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8 *See* discussion in Chapters 2 and 7.

9 *See* discussion in Chapters 2 and 6.

10 National industry share and concentration data are provided for descriptive purposes and to show industry trends. These measures are not suitable for use in analyzing the effects of mergers on competition in relevant antitrust markets.

11 PennWell Corporation, *Pipeline Economics*, OIL & GAS J. 82, 86, 88 (Sept. 8, 2003).

12 As noted in Chapter 6, the *OGJ* survey is not a list of distinct owners. Parent companies sometimes have interests in several listed pipeline companies, and some of the pipeline companies themselves also have interests in several different pipelines. Most pipeline companies listed in the *OGJ* survey that ship crude oil are owned by a single company. In contrast, a large number of pipeline companies that ship refined petroleum products are joint ventures. Therefore, for product pipelines both a table showing shares of pipeline companies (Table 8-2) and a separate table showing shares of owners (Table 8-3) are presented.

13 As discussed below, the Conoco/Phillips merger reduced the number of Explorer owners to seven. Koch's acquisition of BP's and Marathon's shares of Colonial and the Conoco/Phillips merger reduced the number of owners of Colonial to five.

provided. Table 8-3 lists the leading owners of petroleum product pipelines, ranked by barrel-miles of shipments, for 1985, 1990, 1995, and 2001. For the purposes of Table 8-3, total barrel-miles for joint venture pipelines (regardless of whether they were organized as undivided interest or joint stock companies) are attributed to firms in proportion to their ownership shares.[14] Table 8-3 shows that concentration in ownership of product pipeline capacity computed at the national level remains low.[15] The HHI increased modestly from 530 in 1985 to 698 in 2001, with almost all of this modest increase occurring between 1995 and 2001.

Three sizeable acquisitions involving product pipelines have occurred since 2001 and are not reflected in the 2001 data. First, the Conoco/Phillips merger combined Phillips's 6.2% of national barrel-miles with Conoco's 4.6%. Second, Koch, a firm with a small share of United States refinery assets and no branded marketing assets, acquired BP's 17.96% ownership of the Colonial Pipeline. Third, Enterprise acquired from Williams the Mid-America Pipeline Company ("MAPCO") and Williams's 80% interest in the Seminole pipeline. These post-2001 transactions are incorporated in Table 8-3, column 2001*. Taking these transactions into account, the HHI increased to 734.

Mergers and acquisitions were responsible for much of the relatively small increase in concentration between 1995 and 2001.[16] As Table 8-3 shows, the transactions largely responsible for the increase in concentration were Williams's acquisition of MAPCO and the Shell/Texaco joint venture (Equilon), both in 1998. Williams has since sold MAPCO to Enterprise, reducing the calculation of national concentration. As Table 8-3 shows, other large acquisitions during the 1990s (such as Shell/Texaco, Marathon/Ashland, BP/Amoco, and Exxon/Mobil) did not have much impact on national concentration.[17]

Two firms with no refining or marketing assets have acquired refined product pipelines and now have significant ownership positions. Kinder Morgan expanded into refined product

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[14] The purpose of Table 8-3 is to show trends in petroleum product pipeline ownership. For purposes of a competitive analysis in a properly delineated relevant antitrust market, it may be more appropriate to treat joint ventures that are joint stock companies as single competitive entities rather than dividing their capacities among owners. *See* Chapter 6, *supra*, at Section VI.B.

[15] A comparison of Tables 6-4 and 8-3 shows that national industry concentration for petroleum product pipelines is lower than that for crude oil pipelines. Several leading owners of product pipelines are not large crude oil pipeline owners. These firms, which are heavily focused on product transport, include Williams, Kinder Morgan, Koch, and TEPPCO.

[16] The fact that a merger increased national concentration does not imply that the merging companies competed with each other prior to the merger or that the merger increased concentration in any relevant antitrust market. For example, a merger between a product pipeline on the East Coast and a product pipeline on the West Coast would increase national concentration, but it would have no effect on concentration in any relevant market for bulk supply of refined products; nor would it be likely to have any effect on competition.

[17] Part of the settlement in Exxon/Mobil was the divestiture of Mobil's 11.49% share of Colonial pipeline to the existing owners of Colonial. The settlement in Shell/Texaco required the divestiture of either Shell's 24% interest in the Plantation pipeline or Texaco's 14% interest in the Colonial pipeline. Additional divestitures of product pipelines were not required in the mergers discussed, as the FTC did not find a likelihood of competitive harm in other relevant markets involving product pipelines.

pipelines by obtaining a 51% interest in Plantation and by acquiring several smaller pipelines. Enterprise entered in 2002 by acquiring MAPCO and 80% of Seminole.

IV. Entry Conditions for Refined Petroleum Product Pipelines

Aside from profitability, entry conditions for refined product pipelines are similar to those for crude oil pipelines.[18] Product pipelines are subject to economies of scale and require significant sunk costs, and several years may be required to obtain necessary approvals and complete construction for a new pipeline.

Actual entry has been greater for new product pipelines than for new crude oil pipelines in recent years, reflecting the decline in domestic onshore crude oil production and the increasing demand for refined products. Many new product pipelines are converted crude oil and natural gas pipelines. Important new product pipelines include the Centennial, Orion, and Longhorn pipelines. Converted from a natural gas pipeline, Centennial (coupled with recent expansions of the Explorer pipeline) has significantly increased pipeline capacity from PADD III to the Midwest.[19] These expansions appear to have eased summertime gasoline tightness in the Midwest. The recently opened Orion pipeline, owned by Shell Pipeline, transports refined products from Houston to west Texas using a converted crude oil line.[20] Using a converted crude oil line as well, the Longhorn pipeline will also move refined product from Houston to west Texas, and will permit Gulf Coast product to be shipped west of El Paso on other pipelines to destinations such as Phoenix, Tucson, and Albuquerque. Longhorn may become operational in summer 2004, though this opening date is not certain.[21]

V. FTC Enforcement Actions Involving Refined Product Pipelines

As with crude oil pipelines, joint ventures and regulation can be important to competitive analyses relating to refined product pipelines. This section first discusses enforcement actions involving pipeline overlaps only, and then turns to the more complicated analysis of cases involving the elimination of competition between refineries and product pipelines.

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18 *See* discussion in Chapter 6.

19 Centennial is owned by two companies, TEPPCO and Marathon, which each have a one-half interest. Centennial has an initial capacity of 210 MBD. *See* Centennial Pipeline LLC, *Who We Are (2004), available at* http://www.centennialpipeline.com/who_we_are.html.

20 Shell Pipeline Co. LP, *Orion Products System (2004), available at* http://www.shellpipeline.com/cd_maps/08OrionProductsSystem.pdf. Shell is planning to extend this line into New Mexico through Albuquerque into the Four Corners area, and Williams is planning to construct a line from the Four Corners area into Salt Lake City. *See also* Mary Coleman, George Schink & James Langenfeld, *Oil Pipelines' Effects on Refined Product Prices*, submission to the Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products I* (Aug. 2, 2001).

21 California Energy Commission, *Gulf Coast to California Pipeline Feasibility Study* (Commission Report 600-03-014F: Aug. 2003).

A. Cases Involving Pipeline Overlaps

Two FTC merger enforcement actions since 1985 focused on overlaps in refined product pipelines. Both matters involved the Colonial and Plantation pipelines in the Southeast.[22] Colonial and Plantation are regulated common carriers; each is a joint stock company. They are treated as a single entity for purposes of analyzing competitive implications of mergers that would result in ownership overlap between the two pipelines.[23] As Chapter 6 noted, since 1993 product pipelines have been able to use market-based rates if FERC determines that the pipeline lacks market power.

During the early 1980s, the Colonial and Plantation pipelines were the primary sources of refined products for much of the Southeast. The two pipelines follow similar inland routes through the Southeast and compete throughout that area. In general, areas served by these pipelines do not have competitive access to shipments by water.[24] Aside from a small refinery in Yorktown, Virginia, there are no significant refineries located near their routes in the inland Southeast.

The FTC enforcement action in the 1984 Chevron/Gulf matter required a divestiture of one of the parties pipeline interests to prevent ownership overlaps between the Colonial and Plantation pipelines. Similar relief was required in the more recent Shell/Texaco and Exxon/Mobil transactions. In each transaction, the merging parties had minority ownership interests in the two rival pipelines.[25] The chief competitive concern was that these ownership overlaps would facilitate anticompetitive coordination through exchange of competitively sensitive information.[26] In both transactions, the merging parties were required to divest an interest in either the Colonial or Plantation pipeline.

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[22] Colonial and Plantation account for most shipments between PADDs III and I. Total shipments of refined products between PADDs III and I in 2002 were nearly 1.1 billion barrels. Of that, 857 million barrels (78%) were shipped by pipeline and 238 million barrels (22%) were shipped by water. EIA, *Petroleum Supply Annual 2002*, Tables 32-34. At the time of the 1982 Merger Report, pipeline shipments were reported to be approximately 67.5% of all shipments from PADD III to PADD I. 1982 Merger Report 237.

Florida and the southeastern Atlantic states are largely served by barges and tankers coming from Gulf Coast refineries in PADD III; additional water shipments, particularly of heating oil during winter months, move from the Gulf to the Northeast. These water shipments do not compete significantly with Colonial and Plantation in the inland Southeast.

[23] *See* Chapter 6, Section VI.B for a discussion of the distinction between joint stock and undivided interest pipelines and the implications of these differing ownership forms for competitive analysis.

[24] There are a few areas where spurs of these pipelines go toward the Atlantic coast.

[25] The FTC complaints in the latter two matters alleged an "inland Southeast" market for light refined product transportation services. The geographic area was described as containing the inland portions of Alabama, Georgia, Mississippi, North Carolina, South Carolina, and Virginia, which were 50 or more miles away from the ports of Savannah, Charleston, Wilmington, and Norfolk. The Shell/Texaco joint venture would have combined Texaco's 14% interest in Colonial with Shell's 24% interest in Plantation; Exxon/Mobil would have combined Exxon's 49% share in Plantation with Mobil's 11% share in Colonial. Shell/Texaco, Complaint ¶¶ 32,33; Exxon/Mobil, Complaint ¶¶ 45,46.

[26] As discussed below, each pipeline acts as a single competitive entity, so the two competitors in the relevant market would have remained after each merger. The concern was that a merger between partial owners of competing pipelines could enhance the ability of the two pipelines to coordinate pricing or expansion decisions.

In the early 1980s, Colonial had a mainline capacity of 1.908 MMBD, representing 77% of the total combined capacity of the two pipelines. Plantation had a capacity of 559 MBD, or 23% of combined capacity. Colonial had 10 owners in 1982: Gulf, 16.8%; Texaco, 14.3%; Amoco, 14.3%; Cities Service, 14%; Mobil, 11.5%; BP, 9%; Continental, 7.5%; Phillips, 7.1%; Union, 4%; and ARCO, 1.6%. Plantation had 3 owners: Exxon, 48.8%; Chevron, 27.1%; and Shell, 24%.[27]

Both pipelines have since expanded capacity. As of 2000, Colonial had a capacity of 2.35 MMBD,[28] and Plantation had a capacity of 710 MBD.[29] Combined capacity has increased 24% since the early 1980s, but the relative sizes of the two pipelines have not changed. Colonial still accounts for 77%, and Plantation 23%, of combined capacity in the region.[30]

The number of owners of Colonial has fallen from 10 in 1979 to 5 in 2004. Koch acquired BP's 17.96% interest in Colonial in 2002 and Marathon's 2.8% interest in 2003. In 2002, the Conoco/Phillips merger combined those companies' interests in Colonial. Mobil divested its 11.49% interest in Colonial to the other existing owners in the Exxon/Mobil settlement. ARCO also divested its 1.58% interest. Meanwhile, the number of owners of Plantation has fallen from 3 to 2.[31] The current ownership of these pipelines is shown in Table 8-4.

The reduction in the number of owners of Colonial and Plantation is not likely to have competitive implications. Each pipeline is operated as a joint stock company and is a single competitive entity. Therefore, there remain two competitors, Colonial and Plantation, before and after each consolidation. Moreover, neither of the companies that increased their ownership – Kinder Morgan for Plantation and Koch for Colonial – has any apparent incentive nor ability to restrict transport services, as might arise if they had ownership of other potentially competing assets in destination areas.

B. Cases Involving Both Refineries and Product Pipelines

Two merger enforcement actions since 1985 focused on overlaps between refineries and refined product pipelines. The first involved the Chevron/Texaco merger. Texaco and Shell at the time owned 44% and 56%, respectively, of the Equilon joint venture. Under a long-term contract, Equilon controlled most of the output of a St. Louis-area refinery.

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27 1982 Merger Report 235-38.

28 Colonial Pipeline Co., *Colonial Pipeline Announces Mainline Capacity Expansion Plans* (Feb. 1, 2000) (press release), *available at* http://www.colpipe.com/pr_main.asp.

29 Kinder Morgan, Inc. 2001 Form 10-K at 13 (2002).

30 Colonial has recently completed construction of an expansion into Knoxville, Tennessee. Colonial Pipeline Co., *Colonial Completes Construction of Expansion to* Knoxville Area (Feb. 17, 2004) (press release), *available at* http://www.colpipe.com/ex_kntn.asp. It also announced plans to expand capacity into eastern North Carolina and Virginia. Colonial Pipeline Co., *Colonial Pipeline Announces Expansion Projects in North Carolina, Virginia* (Jan. 15, 2003) (press release), *available at* http://www.colpipe.com/press_release/pr_62.asp.

31 Shell's 24% interest in Plantation was sold to Kinder Morgan in the Equilon settlement. Then, in 1999, Kinder Morgan bought Chevron's 27% share of Plantation.

Explorer, a common carrier pipeline organized as a joint stock company, delivers refined products to St. Louis (among other areas). At the time of the Chevron/Texaco merger, Chevron had a 16.7% ownership share of Explorer, with Texaco and Equilon also owning 9.97% and 26%, respectively. The Chevron/Texaco merger would have combined Chevron's interest in the Explorer pipeline with Texaco's direct and indirect (via Equilon) interests in Explorer and its indirect (via Equilon) contractual control of the output of a St. Louis refinery. The FTC alleged that the combined Chevron/Texaco would have had more ability than Texaco alone to block expansions of the Explorer pipeline that would have competed with output of the St. Louis refinery.[32]

In Conoco/Phillips, the Commission alleged anticompetitive effects in bulk supply of refined products in two markets. The merger would have combined a Conoco refinery in the Denver area with Phillips's ownership of an interest in a pipeline that served Denver and was fed by a Phillips refinery. In Salt Lake City, the merger would have combined a Phillips refinery in the Salt Lake City area with a Conoco refinery in Billings, Montana that served the Salt Lake City area through the Pioneer pipeline, in which Conoco had a 50% interest. The FTC required the divestiture of refineries and related assets in both Denver and Salt Lake City areas to address this potentially significant competitive problem.[33]

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[32] Chevron/Texaco, Complaint ¶¶ 44, 45; Analysis to Aid Public Comment.

[33] Conoco/Phillips, Analysis to Aid Public Comment.

Table 8-1 – Shipments of Refined Products Within the United States (Billion Ton-Miles)

	1979		2001	
Mode	**Shipments**	**Percent**	**Shipments**	**Percent**
Pipeline	236.1	44.2	299.1	60.6
Water	257.4	48.2	145.9	29.6
Truck	27.8	5.2	29.7	6.0
Railroad	12.9	2.4	18.5	3.8
Total	534.2	100	493.2	100

Source: Association of Oil Pipelines, *Shifts in Petroleum Transportation*, Table 2 (May 2003).

Table 8-2 – Largest Petroleum Product Pipeline Companies 1985 -2001 (Billion Barrel-Miles Carried)

Pipeline	1985	1990	1995	2001
Colonial	626.2	691.4	682.1	740.7
Explorer	107.7	107.7	126.5	154.8
Plantation	116.0	110.3	123.7	132.0
MidAmerica	43.8	53.4	68.2	105.7
TEPPCO	78.0	67.4	98.6	112.4
Williams	51.2	49.4	58.3	70.5
SFPP		44.3	50.0	61.6
Seminole			40.3	50.2
Buckeye	32.1	35.2	38.3	40.9
Chevron	56.3	45.0	33.7	10.3
Phillips	45.8	40.7	24.9	24.3
Total	1,499.8	1,608.9	1,719.6	1,939.2
Top 5	984.3	1,030.2	1,099.1	1,245.6
Top 5 share (%)	65.6	64.0	63.9	64.2

Source: *Oil & Gas Journal*,"Pipeline Economics" (annual). Ownership based on FERC *Form 6* data. Data from *Oil & Gas Journal* used with permission.

Table 8-3 – Largest Petroleum Products Pipeline Companies: Shares of Barrel-Miles of Product Shipments (%) 1985-2001

Firm	1985	1990	1995	2001	2001*
Williams	3.4	3.1	3.4	11.5	4.0
MAPCO	3.5	4.0	5.8		
Enterprise					7.5
Equilon				11.2	11.2
Shell	4.6	4.5	4.4		
Texaco	8.1	8.7	7.8		
Unocal	9.0	9.0	8.3	9.3	9.3
BP-Amoco				8.4	1.6
BP	4.5	4.9	0.6		
Amoco	7.1	9.2	8.3		
KinderMorgan				7.8	7.8
Citgo	6.5	6.7	6.7	7.2	7.2
ConocoPhillips					10.8
Phillips	6.7	6.0	5.9	6.2	
Conoco	4.6	4.8	4.6	4.6	
TEPPCO/Pan Handle Eastern	5.5	5.0	5.7	5.8	
ExxonMobil				5.0	5.0
Exxon	4.6	4.1	4.2		
Mobil	6.3	6.4	5.6		
Koch		2.2	4.8	4.4	11.3
Marathon-Ashland				3.9	3.9
Marathon	1.4	2.6	3.5		
Chevron	5.3	6.3	5.4	3.1	3.1
	Concentration				
Measure					
4-Firm (%)	30.9	33.6	31.1	40.4	42.6
8-Firm (%)	54.5	57.3	54.1	67.4	68.1
HHI	530	566	531	698	734

Source: *Oil & Gas Journal*, "Pipeline Economics" (annual). Ownership based on FERC *Form 6* data. Data from *Oil & Gas Journal* used with permission.

Table 8-4 – Current Owners of Colonial and Plantation Products Pipelines

Colonial Owners	%	Plantation Owners	%
Koch	28.09	KinderMorgan	51
HUTTS	23.44	ExxonMobil	49
Shell	16.12		
Citgo	15.80		
ConocoPhillips	16.55		

Source: Colonial Pipline Companyhttp://www.colpipe.com/ab_oc.asp; Plantation Pipeline Company from Kinder Morgan Energy Partners LP *Form 10-K*, 12 (2001).

Chapter 9

Structural Change in Product Terminals and Gasoline Marketing

This chapter discusses the last two levels of the petroleum industry – product terminal services and gasoline marketing. Terminals receive bulk supply of refined products from pipelines, tankers, barges, or adjacent refineries and provide storage and dispensing facilities. The FTC has prevented problematic consolidations of competing terminals in several petroleum mergers.[1] Immediately downstream from terminal services is gasoline marketing – wholesale and retail activities, including product branding, rack wholesale services, truck deliveries, and operation of service stations. In a number of petroleum mergers, the FTC has alleged likely competitive effects in gasoline marketing, and has required significant divestitures to ameliorate the Commission's concerns.[2]

In Section I of this chapter, the focus is on terminal services, with Section II focusing on wholesale and retail distribution of gasoline. Section I provides an introduction to terminal services, discusses how the agency defines antitrust markets for product terminal services, provides data on trends in the number and ownership of product terminals, and, finally, discusses entry conditions. Section II discusses how the agency defines antitrust markets for wholesale and retail gasoline distribution. A review of the distribution of gasoline from product terminals to retail customers follows, focusing first on wholesale distribution (from product terminals to retail outlets) and then on retail distribution (to final consumers). State-level concentration data are provided for gasoline marketing, at both the wholesale and the branded retail level. The chapter next discusses factors that impact entry into the business of gasoline marketing, and concludes with an analysis of hypermarkets and their increasing impact in these markets.

I. Product Terminal Services

A. Antitrust Markets for Product Terminal Services

Most light petroleum product terminals receive bulk supplies by pipeline, although some are supplied by tanker or barge (or, much more rarely, by rail). Most refineries also have an adjoining product terminal for local distribution. Refined products are segregated into several separate storage

[1] Discussed, *supra*, in Chapter 2.

[2] Other kinds of refined petroleum products have marketing activities distinct from those involving gasoline. Mergers may have competitive implications for marketing of these other types of refined products. For example, as described in Chapter 2, the FTC sought relief in Chevron/Texaco with regard to the marketing of general aviation fuel.

tanks at the terminal location. Terminals also have dispensing equipment, referred to as "racks," for use in transferring product from storage tanks to trucks. The "rack price" refers to the price at which sales are made at terminal racks. Trucks, which typically have about an 8000-gallon capacity, deliver product to service stations.

A primary function of a terminal is to provide local storage and dispensing services. The contribution of terminal services costs to the total cost of delivered petroleum products is relatively small. Throughput (or dispensing) fees vary but typically are about one-half cent to one cent per gallon, and the cost of storage is also typically about one-half cent per gallon per month.[3] With inventory turnover ranging from about once every 10 days to once every 90 days (depending on location), terminal storage costs amount to approximately 0.16 cents to 1.5 cents per gallon.[4]

Terminal ownership varies. Some terminal owners are involved in activities either upstream or downstream from the terminal level. So-called "proprietary" terminals are generally owned by firms with refining and/or branded marketing operations. A proprietary terminal distributes product primarily to retailers or jobbers that are associated with that firm's brand. Nevertheless, other marketers and brands may have access to a proprietary terminal through various contractual arrangements, including exchanges and throughput agreements.

So-called "public" terminals are owned and operated by pipeline companies or other firms with no upstream or downstream interests. While these terminal operators may sometimes buy bulk supply for their own account for resale at the rack, they also provide terminal storage and dispensing services to local marketers, including refiners and large jobbers.

As with petroleum pipelines, some terminals are owned through joint ventures with two or more owners, such as major marketers with refinery interests. Terminal owners may lease portions of a terminal's capacity to marketers under long-term contracts. Competitive analyses of terminal joint ventures and long-term lease arrangements must sometimes consider whether capacity at a given terminal should be attributed to one or more entities. Another consideration in competitive analyses is that terminal prices and terminal access are not regulated.

Where the merging companies have terminals serving the same geographic area, the FTC has typically identified terminal services for gasoline and other light petroleum products as a relevant product market. This reflects the fact that many terminals provide storage and dispensing facilities for other products (such as diesel fuel) in addition to gasoline. A narrower product market limited to a particular refined product, such as gasoline, may be appropriate in some circumstances. For example, some terminals in a geographic area might offer storage and dispensing services only for distillates,

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3 J. Petrowski, *Terminal Valuation: Should Retailers Invest Further Upstream in Today's Market?*, NATIONAL PETROLEUM NEWS 50 (Aug. 2002).

4 *Id.* at 49.

and thus might not constrain an anticompetitive price increase for storage and dispensing of gasoline. However, such distillates-only terminals might be included in the relevant product market (or considered to be potential entrants) for a merger between gasoline terminals if the costs of converting or adding facilities to handle gasoline (including opportunity costs from forgone sales of other products) are minimal and the changes can be accomplished within the time-frames indicated in the Merger Guidelines. In addition, variations in gasoline blends due to differing environmental regulations may reduce substitutability among nearby terminals.

While some terminals are geographically isolated, many are located in clusters that serve densely populated, high-demand areas. Terminals in a cluster often receive their bulk supplies from common pipeline or water sources. A cluster may or may not represent a relevant geographic market for the purposes of analyzing a merger of two nearby terminals. The size of the relevant geographic market depends primarily on incremental truck transportation costs.[5] Trucks using a terminal typically supply retail locations within a limited radius, such as 50 to 75 miles.[6] The relevant geographic market for terminal services may nonetheless extend beyond the merging terminals' service areas. For example, although terminal clusters 100 miles apart might generally be outside each other's service areas, changes in relative prices at clusters may shift the boundary between their service areas. If prices at one terminal cluster rise, it may be profitable for marketers to shift some business to an alternative cluster where prices have not increased. If enough business is shifted to make an anticompetitive price increase in the first cluster unprofitable, a broader geographic market may be appropriate.

B. Trends in Number and Ownership of Product Terminals

There are no reliable publicly available data on trends in concentration in terminal services in economically meaningful relevant geographic markets. The Bureau of the Census tracks the number of product terminals nationally and by state. These data, presented in Table 9-1 and aggregated to the PADD or sub-PADD level, show a decline in the number of terminals between 1982 and 1997, the last year for which data are available. Table 9-1 also shows the number of terminals owned by "refiner-marketers" and by "others," a distinction that corresponds roughly to that between proprietary and public terminals. The percentage decline over the period was similar for refiner-marketer terminals (45%) and for terminals owned by others (48%), although there were differences in the two groups' relative changes across regions. For example, the decline in the number of refiner-marketer terminals was most pronounced in New England (PADD I-A), in the Mid-Atlantic region (PADD I-B), and on the West Coast (PADD V). For the more recent period between 1992 and 1997,

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5 Whether a more distant terminal is a practical substitute for nearby terminals also depends on other factors such as capacity availability and bulk supply conditions at the more distant terminal.

6 This distance may vary depending on demand density, traffic congestion, and relative prices at alternative terminals.

refiner-marketer terminals continued to decline sharply in numbers (24% decline nationally and either zero or negative changes in all regions at the PADD or sub-PADD level), while other owned terminals have become more numerous (a 10% increase nationally, and either percentage gains or smaller percentage declines than refiner-marketer terminals at the PADD or sub-PADD level). These quantitative changes between 1992 and 1997 are consistent with even more recent transactions in which refiners and major brand operators have exited the terminal business in certain locations by selling their terminals to independent, public operators.

Terminal closure and consolidation have been associated with a decline in terminal inventory holding since the 1980s.[7] The development of "in-line terminal blending" eliminated the need for storage of certain refined products, such as mid-grade gasoline, which can be blended at the terminal from stocks of regular and premium grade gasolines. These changes have reduced the demand for terminal storage space and have encouraged the closing of marginal terminals and increased joint use of underutilized facilities through product exchanges and joint ventures. Firms have also taken advantage of scale economies by contracting with other terminal operators rather than running their own terminals.[8] Adoption of improvements in supply management technologies, such as just-in-time inventory methods, also contributed to the decline in inventories.[9] Some refiners and major brand marketers have exited from the terminal business in certain locations, selling their terminals to independent public operators. Examples of such transactions include the 1998 Colonial Pipeline acquisition of six terminal facilities from Conoco and Murphy Oil;[10] Kinder Morgan's recent purchase of five product terminals in the western U.S. from Shell;[11] and Buckeye Partners' acquisition of BP Amoco's Taylor, MI terminal in 2000.[12]

C. Entry into Product Terminals

Terminals are specialized facilities with a high ratio of sunk to total costs. Their operations exhibit scale economies because staffing costs do not vary much with the size of the facility and because the capital costs per unit of storage decline as storage volumes increase.[13] Nonetheless,

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7 National Petroleum Council, *U.S. Petroleum Product Supply Inventory Dynamics* 37-38 (Dec. 1998).

8 *Id.* at 33-34.

9 *See* the discussion in transcript of Federal Trade Commission Conference, *Factors That Affect Prices of Refined Petroleum Products II* 53-56 (May 8, 2002).

10 Colonial Pipeline Co., *Terminal Services*, *available at* http://www.colpipe.com/sv_ts.asp.

11 *Kinder Morgan to Purchase Five Terminals*, Modern Bulk Transporter (Oct. 1, 2003).

12 Buckeye Partners, L.P., *Buckeye Partners Acquires BP Amoco Terminal* (Mar. 21, 2000) (press release), *available at* http://www.buckeye.com/News%20Releases/2000%20News%20Releases/03-21%20Acquisition%20of%20BP%20Terminal.asp.

13 Common to many industrial processes, this type of scale economy is sometimes referred to as the *"two-thirds rule*." This relationship occurs when capital costs are largely determined by the surface area in a process (in the case of terminals, the area of tank shells), while output (here, storage capacity) depends on the physical volume enclosed. Since surface area rises at only the two-thirds power of physical volume, unit costs tend to decline, at least up to the point where other physical constraints may come into play.

product terminals vary greatly in size as measured by storage capacity, in large part determined by the extent of local demand. Marine terminals supplied by tanker, however, may be larger than terminals receiving supply by pipeline because marine cargoes often exceed the volumes of typical pipeline tenders. In addition to sunk costs and scale economies, entry into terminals may be deterred or not timely due to zoning and environmental issues. Excess terminal capacity in recent years has also discouraged *de novo* terminal entry.

II. Gasoline Marketing

A. Antitrust Markets for Gasoline Marketing

Gasoline marketing comprises wholesale and retail distribution of both branded and unbranded gasoline. Branded gasoline is sold under a trade name (or "flag") of a petroleum company. Branded gasoline has traditionally been associated with major oil companies, which have refining, terminal, and other assets upstream from marketing. Branded gasolines contain proprietary additive packages that are typically unique to each brand and added at terminals before trucks deliver the product to retail outlets flying the brand's flag.

Unbranded gasoline is typically sold under a private label or an independent trade name by firms that concentrate on wholesaling or retailing and have few or no assets upstream from marketing. Unbranded gasolines, which generally contain generic additive packages added to the product at terminals, may be sold at terminals by marketers that primarily supply branded product or by firms with no branded presence (such as public terminal owners or refiners that have little or no distribution of their own).

Recent FTC merger enforcement actions in gasoline marketing all involved alleged competitive problems downstream and independent of product terminals, although the terminology in identifying the relevant markets has evolved since the late 1990s. In Shell/Texaco and BP/Amoco, the FTC expressed concerns downstream of product terminals in "wholesaling and retailing" or "wholesaling" markets. The same concerns, however, were expressed in terms of relevant markets for "gasoline marketing" in the FTC's enforcement actions in Exxon/Mobil and Chevron/Texaco. These cases are distinguished from earlier enforcement actions such as Pacific Resources/Shell and Sun/Atlantic, where the horizontal overlap generating the competitive concern was at the terminal level and divestitures of marketing assets were required to make divested terminals viable.[14]

The relevant markets for gasoline marketing alleged by the FTC have included both branded and unbranded gasoline because of potential substitution at both the jobber and consumer levels. The FTC typically has alleged geographic markets corresponding to metropolitan or similarly sized areas. Broader or narrower geographic markets may sometimes be appropriate. In all cases, the potential for switching to other

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[14] *See* Chapter 2 for additional discussion of the FTC merger enforcement actions in gasoline marketing.

locations by gasoline buyers will determine the geographic market. Jobbers and other independent distributors in many areas are important purchasers at wholesale terminal racks. A marketer may offer rack supply to jobbers and other distributors either by being integrated into terminal services or by contracting for terminal services.[15] As a result, an important potential response to an anticompetitive wholesale price may be the switching of jobbers or other distributors to more distant terminals. The magnitude of this response, as in the case of defining relevant geographic markets for terminals, will primarily depend on the costs of trucking from terminals to retail sites. If economically advantageous, a jobber may switch to a terminal 50 miles away to obtain a lower price for rack product. Where switching by jobbers and other distributors is potentially important, the geographic markets for gasoline marketing may be closely related to the geographic markets for terminal services.

Individual consumers, of course, are unlikely to react to an anticompetitive price increase by switching purchases to stations 50 miles away. There may be areas where jobber switching in response to anticompetitive wholesale prices at the rack is not very important, either because of extensive vertical integration between marketers and retail operations or due to restrictions imposed by marketers on the terminals where their branded jobbers may pick up gasoline.[16] In these cases, switching at the consumer level will become more important in determining relevant geographic markets in gasoline marketing.

Based solely on the behavior of individual consumers, one might think that relevant geographic markets for gasoline retailing are relatively small. However, this overlooks the nature of constraints on retail pricing in a metropolitan area. The prices charged by a retail station may be constrained by prices charged by other stations a mile or two away, while the prices of the latter constrain additional stations another mile or two away, and so on. The very nature of the product also involves mobility. Consumers may purchase gasoline near their place of work, near their home, near where they shop, or anywhere between these locations. As a result, the relevant geographic market might be relatively broad, perhaps as large as an entire metropolitan area. On the other hand, where stations are relatively isolated, smaller markets may be appropriate.

B. Wholesale Distribution of Gasoline from Product Terminals to Retail Outlets

The means by which gasoline is distributed from product terminals to retail outlets can have important

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[15] A marketer would also have to provide for bulk supply to terminals, either by being vertically integrated into refining or through contractual arrangements with other firms operating refineries or offering bulk supply contracts.

[16] For example, in Shell/Texaco, the FTC noted that six vertically integrated oil companies controlled about 90% of the gasoline sold both at the wholesale and retail levels. The companies also required their branded jobbers to buy gasoline at San Diego terminals, where they set the wholesale prices. This restriction prevented potential switching by jobbers to terminals outside the San Diego area. Shell/Texaco, Analysis to Aid Public Comment.

implications for the competitive analysis of particular mergers affecting marketing.[17] Under *direct distribution*, a

[17] In response to concerns that differences in the prices of gasoline in San Francisco, Los Angeles, and San Diego might be in part a result of anticompetitive conduct, in 1998 the FTC opened an investigation into gasoline marketing and distribution practices employed by the major oil refiners in Arizona, California, Nevada, Oregon, and Washington. Two distribution practices, known as "zone pricing" and "redlining," were the focus of the Western States investigation. Zone pricing is the practice of a refiner (or other wholesaler marketer) to charge different delivered wholesale dealer tank wagon ("DTW") prices to lessee dealer stations located in different areas. DTW price zones are roughly drawn to define an effective area of local competition among retailers, based on geographic features and local demand patterns. Redlining is a refiner's practice of preventing its jobbers from delivering gasoline to the refiner's lessee dealer stations, and the refiner's practice of preventing its jobbers from opening retail stations bearing the refiner's brand in certain areas. Observers have raised the concern that zone pricing and redlining reflected coordinated interaction among owners of major brands to raise gasoline prices, and that use of the practices supported *reductions* in wholesale prices for branded gasoline in specific local areas for the purpose of predation against, or to deter entry by, competing stations. *See, e.g.*, Governor's Task Force on Gasoline Zone Pricing, *Task Force Report on Gasoline Zone Pricing* 10 (Maryland Energy Administration, Sept. 14, 2001).

The FTC's Western States investigation uncovered no evidence that refiners agreed among themselves in establishing zone pricing or redlining practices. The investigation uncovered no evidence of horizontal agreements on price or output or on the adoption of any vertical distribution practice at any level of supply. Also, the investigation uncovered no evidence that any refiner had the unilateral ability profitably to raise prices or to reduce output at the wholesale level in any market. *See* Statement of Commissioners Sheila F. Anthony, Thomas B. Leary and Orson Swindle, Concerning Western States Gasoline Pricing Investigation. *See also* Statement of Commissioner Mozelle W. Thompson, Concerning Western States Gasoline Pricing Investigation (voting to close investigation, but stating he was "somewhat troubled by the practice of site-specific redlining that some West Coast refiners utilize as part of their distribution strategies").

Absent evidence of concerted action, these vertical restraints would be evaluated under the antitrust rule of reason, which requires a balancing of potential procompetitive and anticompetitive effects. Therefore, a necessary condition for an antitrust attack on these practices would be proof of sustained anticompetitive effects or proof that a refiner had the ability profitably to raise market prices or reduce market output over a sustained period as a result of these practices. The Commission's "investigation uncovered no evidence that any refiner had the ability profitably to raise price market wide or reduce output at the wholesale level, nor did it find a situation in which a refiner adopted redlining in a metropolitan area and increased market wide prices," nor did the investigation "uncover any evidence of conduct by the Western States refiners that would, on balance, result in likely consumer harm sufficient to establish an antitrust violation." *Id.* With regard to zone pricing, geographic variation in wholesale gasoline prices does not by itself suggest competitive problems; there is often substantial price variation in real world competitive markets. Additionally, the price zones used by different refiners often do not coincide; this fact suggests that refiners are not colluding on zone pricing. Zone pricing for gasoline is also common across the U.S. The use of zone pricing in areas with significant entry by gasoline stations undercuts arguments that zonal price reductions are an important entry barrier. For example, a study by the Utility Consumer Action Network noted the use of price zones in San Diego California. UCAN, *Documentation of Gasoline Price Manipulation in SanDiego County* (Aug. 7, 1998), *available at* http://www.ucan.org/consumer_info/gasdocs. As discussed *infra*, despite the presence of price zones, Costco successfully entered gasoline retailing in San Diego. The expansion of gasoline retailers with innovative formats in many other parts of the country, discussed *infra*, also runs counter to the proposition that price zones are an important entry deterrent.

Finally, there may be legitimate business justifications for zone pricing and redlining. Redlining, for example, allows refiners to make sure that jobbers serve rural locations, instead of diverting the gas they buy to locations in more accessible areas. Prices zones allow more flexibility to refiners to meet localized competition, thereby resulting in lower prices in areas with more competition than might otherwise be the case. *See generally* David W. Meyer & Jeffrey Fischer, *The Economics of Price Zones and Territorial Restrictions in Gasoline Marketing* (2004) (FTC Bureau of Economics Working Paper); Cary A. Deck & Bart J. Wilson, *Experimental Gasoline Markets* (2003) (FTC Bureau of Economics Working Paper). (Deck and Wilson, in an experimental economics study of zone pricing in a laboratory environment with two types of geographic retail areas, isolated areas served by a single station and an area served by a cluster of four stations. They found that when zone pricing was banned, consumers in the marketer delivers gasoline to (1) retail outlets that are owned and operated by the marketer itself (so-called "company owned and operated stations," or "co-op" stations); (2) retail outlets that are owned by the marketer but operated by independent "lessee" dealers; and (3) retail outlets that are owned and operated by independent "open" dealers. The wholesale price for co-op stations is an unobserved, internal transfer price. The delivered wholesale price charged by the marketer to lessee dealers and directly served open dealers is known as the DTW price. By contract, the marketer is the exclusive supplier to its lessee dealers and open dealers. Lessee dealers also pay a monthly rental payment to the brand owner.[18]

Alternatively, a marketer may use *jobber distribution* to supply retail sites. Under jobber distribution, a marketer sells gasoline to jobbers at the terminal rack, where product ownership is transferred. Jobbers then distribute the gasoline to retail stations that they own and operate, that they own but lease to third parties, or that are independently owned and operated.[19] Branded jobbers purchase gasoline from branded marketers and distribute it to stations that are licensed to sell under the marketer's brand; in many instances jobbers own these stations, but in other cases they do not.

The branded marketer sells to jobbers at a rack price. Jobbers may also negotiate contracts with the marketer that provide the jobber with some priority of supply and provide discounts, allowances, and rebates from rack prices. Branded jobbers may also receive loans or incentive payments from marketers to modernize or improve the jobbers' retail outlets. These loans are often repaid through charges assessed against the purchase of gasoline from the marketers.[20]

Finally, unbranded jobbers purchase unbranded gasoline at the terminal rack. In some cases, unbranded jobbers may have contracts to be supplied at some discount from posted rack prices, but in other cases they may buy at posted rack prices with no ongoing contractual commitments or supply assurances. Some unbranded

clustered area paid higher prices than when zone pricing was permitted. They found that consumers in isolated areas paid the same prices whether or not zone pricing was allowed.) Neither economic principles nor empirical evidence provides a basis for a *presumption* that these practices result in higher retail gasoline prices.

[18] The marketer directly sets the retail prices charged by co-op stations. Lessee and open dealers set their own retail prices, although the marketer's control over DTW prices gives it significant influence over retail prices. In addition, many lessee dealer franchise agreements contain clauses requiring minimum purchases of gasoline from the marketer, thereby encouraging dealers' selling efforts and so limiting dealers' ability to set unduly high retail prices. Contracts with branded jobbers may also contain minimum volume requirements, as discussed above.

[19] In addition, jobbers typically sell gasoline directly to commercial end-users.

[20] Such loans may take various forms. Under some "image programs," for example, an outlet receives a loan from a marketer in the form of a discount on purchased gasoline for a specified period of time (*e.g.*, from 1 to 3 years). This loan is then implicitly paid back through a commitment by the outlet to purchase gasoline at specified prices for a period following the discount period (*e.g.*, from 3 to 7 years). If the retailer rebrands before the image loan is forgiven, the retailer must then reimburse the wholesaler for the unamortized portion of the loan.

jobbers own their own retail brands and outlets.[21]

Wholesale distribution patterns differ across the country. The extent to which these distributional alternatives are present in a given market has important implications for the competitive analysis of marketing mergers because of the different potential for brand switching by jobbers or retailers in response to an anticompetitive price increase. Co-op outlets have no ability to switch brands should the firm's internal transfer price increase. Lessee dealers also have no ability to switch brands should the DTW price increase as a result of a merger. By contrast, open dealers own their stations and can switch brands (subject to the terms of their contracts), although their willingness to do so will depend on the terms and availability of other brands.

Branded jobbers facing higher rack prices may be able to switch brands to avoid a price increase, although costs from loans or contractual commitments to their current brand owner may limit switching. Unbranded jobbers may be able to switch wholesale rack suppliers without such contractual encumbrances. Generally speaking, the more that brand-owners in a particular area are vertically integrated across the wholesaling and retailing functions (either through ownership of retail assets or partially through contractual relationships with jobbers), the less potential there is for brand switching by jobbers and retailers in response to a wholesale price increase. If vertical integration is extensive, defeat of an anticompetitive price increase by incumbents may require the entry of new brands and the building of new retail outlets.[22]

[21] For example, a group of Mid-Atlantic distributors has formed Liberty Petroleum, LLC, in an attempt to establish Liberty as a strong regional retail brand.

[22] These considerations should not imply that vertical integration is *per se* illegal or even usually anticompetitive. The economics literature has identified numerous efficiency-enhancing motives for vertical integration, including (1) elimination of double marginalization; (2) reducing transactions costs; (3) preventing opportunism; and (4) eliminating distortions in input choices when firms can substitute between inputs. *See* Michael G. Vita, *Regulatory Restrictions on Vertical Integration and Control: The Competitive Impact of Gasoline Divorcement Policies*, 18 J. Reg. Econ. 217 (2000), and sources cited therein. *See also* Dennis Carlton & Jeffrey Perloff, MODERN INDUSTRIAL ORGANIZATION 377-395 (3rd ed. 2000); W. Kip Viscusi, John M. Vernon & Joseph E. Harrington, Jr., ECONOMICS OF REGULATION AND ANTITRUST 218-33 (3rd ed. 2000). For a discussion of the case law on vertical integration, *see* Andrew I. Gavil, William E. Kovacic & Jonathan B. Baker, ANTITRUST LAW IN PERSPECTIVE: CASES, CONCEPTS AND PROBLEMS IN COMPETITION POLICY 339-417, 689-756 (2002); ABA Section of Antitrust Law, ANTITRUST LAW DEVELOPMENTS 130-228, 253-56 (5th ed. 2002).

Studies of state divorcement laws, which restrict refiners' ability to own or operate gasoline retail outlets, have shown that retail prices are lower where there is more vertical integration between refining and marketing. *See* Vita, *supra*; Asher A. Blass & Dennis W. Carlton, *The Choice of Organizational Form in Gasoline Retailing and the Cost of Laws that Limit that Choice*, 44 J. L. ECON. 511 (2001) (estimating that divorcement increases costs of operation by about three to four cents per gallon). *See also* J.M. Barron & J.R. Umbeck, *The Effects of Different Contractual Arrangements: The Case of Retail Gasoline Markets*, 27 J. L. ECON. 313 (1984). A study of an acquisition of an independent marketer by a refiner with competing marketing assets concluded that retail prices increased as a result. Justine Hastings, *Vertical Relationships in Retail Gasoline Markets: Empirical Guidance from Contract Changes in Southern California*, 94 AM. ECON. REV. 317 (2004). However, possible effects from the rebranding of the acquired firms' retail outlets, as distinct from possible effects from increased vertical integration itself, complicate the interpretation of this study's results. For a review of some of the empirical studies of vertical integration in the petroleum industry, *see* John Gewecke, *Empirical Evidence on the Competitive Effects of Mergers in the Gasoline Industry*, submitted in conjunction with the Federal Trade Commission

Available data do not provide a comprehensive, detailed picture of differences in the degree of vertical integration between the wholesale and retail levels, either across areas or over time. EIA data on refiners' disposition of gasoline by class of trade, however, do provide useful insights on some trends in such vertical integration. Table 9-2 summarizes data on the distribution of refiners' gasoline sales volumes from 1994 through 2002, nationally and by PADD or sub-PADD.[23] Refiner gasoline volumes are broken down into direct sales to co-op stations, sales to retailers on a DTW basis,[24] and sales at the terminal rack to jobbers.

Rack sales are the largest of these three channels nationally, with 61% of sales. DTW and co-op sales roughly split the remainder, with 20% and 19%, respectively. Between 1994 and 2002, the share of national sales accounted for by rack sales increased by 6% and the share accounted for by co-op sales increased by about 1%. Thus, on balance, the degree of vertical integration between wholesale and retail nationally has not increased (and arguably has decreased somewhat).

The relative importance of the three distribution channels differs markedly across the country.[25] PADDs II, III and IV have much higher percentages of distribution at rack and much lower percentages attributable to DTW than the nation as a whole. Within PADD I, DTW sales are more important in the New England and Mid-Atlantic states (PADDs I-A and I-B) than in the Southeast (PADD I-C). Finally, the percentage of disposition to DTW is significantly higher (and rack sales are lower) in PADD V,[26] indicating that there is more vertical integration between wholesale and retail functions on the West Coast than elsewhere.[27]

Conference, *Factors That Affect Prices of Refined Petroleum Products II* (May 8, 2002).

23 Refinery gasoline disposition data from EIA Form 782-A broken out by type of disposition (rack, DTW, company-operated outlets) are not available prior to 1994. The categories presented in Table 9-2 (company owned and operated, DTW, and rack) refer to the disposition of gasoline below the terminal level. Bulk shipments are a fourth category of refinery gasoline disposition collected by EIA Form 782-A. These bulk shipments are not reflected in Table 9-2. EIA defines bulk shipments as wholesale sales of gasoline in individual transactions which exceed the size of a truckload. Bulk sales include large volume sales made at the refinery gate or at the terminal level, sometimes under spot transactions and sometimes under term contracts between refineries and large marketers. Exchanges may also be included in bulk sales. Nationally the share of bulk gasoline volumes relative to total refiner volumes (the sum of co-op, DTW, rack and bulk volumes) remained relatively stable from 1995 to 2002, ranging from 10.5% to 11.5%. The share of bulk volumes to total volumes is greatest in PADD III (roughly 27% of total volume) and smallest in PADD IV (less than 1% of total volume).

24 DTW volumes include gasoline sold to both lessee and open dealers. Data are not publicly available that would segregate lessee and open dealer volumes. However, lessee dealers appear to outnumber open dealers by a wide margin. According to one recent trade press article, lessee dealers outnumber open dealers by about 3-1 among the major oil brands. National Petroleum News Market Facts, *How Companies Handle Product Distribution 1998*, 33-35 (mid- July 1999).

25 Substantial variations in mode of distribution also exist across more narrowly defined areas. Station densities are higher in more urbanized areas, for example, and this density often generates sufficient scale economies to encourage direct supply by marketers to co-op or lessee dealer stations. Marketers are more likely to rely on jobbers in less populated areas, because jobbers can achieve distributional sales economies by carrying multiple brands.

26 The level of co-op sales is about the same as in other areas.

27 DTW share has declined somewhat since 1994 in favor of co-op sales. The relatively high degree of

Jobbers' ability to discipline an anticompetitive price increase by marketers has been an important element in the FTC's analysis of marketing mergers. The FTC has required divestiture of marketing assets in connection with mergers in areas where rack sales and jobbers are less extensive (*e.g.*, in metropolitan areas of the Northeast in Exxon/Mobil), while not taking enforcement actions where rack sales are more prominent (*e.g.*, in mid-continent U.S. in Conoco/Phillips).[28]

Though less visible than consolidations among major oil companies, there has also been consolidation among jobbers. One industry observer predicted that the smallest jobbers (those with less than $10 million in annual motor fuel revenue) lacked the resources to achieve an efficient scale and were not likely to survive in the long run, while the largest jobbers (those with more than $25 million in annual motor fuel revenue) were better positioned for the future. The observer contended that mid-sized jobbers (those with between $10 million and $25 million in motor fuel revenues per year) face a choice: "grow, sell, or sharpen their focus."[29] Competitive pressures from the expansion of hypermarkets into gasoline retailing and increasing capital requirements at the retailing level have been factors motivating some jobber consolidations. In addition, since the early 1990s major brands have been instituting minimum volume requirements for their jobbers.[30] From the perspective of the brands, these contractual provisions promote efficient distribution of gasoline because they encourage distributor scale economies and selling effort. Some smaller jobbers have reportedly formed joint ventures with other similarly positioned jobbers to be able to purchase the required minimum volumes.[31]

C. Retail Distribution of Gasoline

Gasoline retailing has undergone important changes since the early 1980s. These changes are significant to the competitive analysis of gasoline marketing overlaps, because they impact the nature and degree of price and non-price competition.

1. *Changes in Retail Format*

The number of gasoline stations has declined since the 1980s. In 1981, there were just under 216,000 services stations in the U.S.[32] Table 9-3, derived from the annual retail gasoline outlet survey conducted by *National Petroleum News* since 1991, summarizes the number of retail outlets selling gasoline by state since 1991.[33] While the number

vertical integration between wholesale and retail on the West Coast dates back to at least 1994, and therefore predates the wave of large petroleum mergers that began in 1997.

28 Marketing divestitures have also occurred on the West Coast in conjunction with refinery divestitures to help ensure the viability of the refinery divestiture.

29 Kevin Fiala, *Jobbers Who "Do Something" Will Succeed in This Time of Consolidation*, NATIONAL PETROLEUM NEWS 33 (July 2002).

30 Alan Kovski, *BP sets minimum volume requirements for jobbers selling company's gasoline; BP Oil Co.*, THE OIL DAILY (Mar. 21, 1994).

31 Keith Reid, *Majors Exiting Retail? No exit in sight but a major transition is underway*, NATIONAL PETROLEUM NEWS 16 (Oct. 2003).

32 1982 Merger Report 275-76.

33 *National Petroleum News* adopted the retail gasoline outlet survey in 1991 to provide a more accurate universe figure. The survey attempts to count all sites where motorists can purchase gasoline at retail

of gasoline outlets fell from over 200,000 in the early 1990s to under 174,000 in 2000-2002, Table 9-4 shows that the volume of gasoline sold through gasoline retailers increased by roughly 9% between 1994 and 2001.

Historically, the major integrated oil companies had viewed the service station retail site as the preferred distribution format. The data in Table 9-5 reflect a decline in traditional stations with service bays and relatively low gasoline sales volumes. In their stead, the number of higher-volume outlets – frequently with convenience stores but with limited or no auto repair service capabilities – has increased. This shift was becoming visible in the early 1980s. At that time, the average service station had one or more service bays and six to nine gasoline pumps, and sold approximately 60,000 gallons of gasoline a month.[34] The 1982 Merger Report noted that the major oil companies were moving toward a new model of retail gasoline distribution because of mounting competition from higher-volume, lower-cost independent stations and the need to replace declining service bay revenues.[35] With the introduction of quick lube services, specialty tire retailers and other specialty auto service centers, other retailers frequently offered the automotive accessories and maintenance and repair services that gasoline service stations had once provided. Many stations attempted to replace these lost auto accessory and maintenance revenues with sales of other products, such as food and general merchandise, and by concentrating on formats that sold higher volumes of gasoline per outlet.

The 1980s saw the transition from the traditional gasoline service station to the convenience store selling gasoline. As this shift continued in the 1990s, a new breed of convenience stores evolved that provided significant competition to traditional gasoline retailers in many areas. Independents such as RaceTrac, Sheetz, QuikTrip, and Wawa succeeded by expanding on the existing convenience store concept. These independents, sometimes referred to as "pumpers" because of their large fuel throughput, typically had large convenience stores with multiple fuel islands and multiple-product dispensers ("MPDs"). With significantly higher gasoline volumes and additional in-store revenue streams, these large private brand retailers became high-volume, low-price gasoline retailers and successfully captured significant retail market share from traditional branded

pumps, including service stations, convenience stores, car washes, unattended fuel sites, truckstops, and garages that sell gasoline. This was an improvement upon the U.S. Census Bureau's Census of Retail Trade, which counted only service stations that generated over 50% of their revenues from fuel sales. According to private communications between the authors and *National Petroleum News*, however, measurement difficulties in the early 1990s created large year-to-year variations in the NPN data for certain regions, particularly in PADD IV. To account for some of these measurement difficulties and the resulting wide, year-to-year swings in station counts, Table 9-3 presents the station counts based on three-year averages (other than for 2000 and 2001, when a two-year average is used because only two years of data are available).

[34] EIA, *The Motor Gasoline Industry: Past, Present, and Future* 21-27 (1991).

[35] The 1982 Merger Report discussed the majors' attempts to meet increased competition from independents by lowering costs, introducing higher-volume stations, and selling or closing many lower-volume (higher-cost) sites. 1982 Merger Report 274, 294.

outlets in many parts of the country.[36] The major oil companies responded to the success of the large private brand marketers by creating or expanding their own convenience store offerings, such as Mobil's On-The-Run. The majors also responded by replacing outdated fuel pumps with higher-volume multi-dispenser islands. Table 9-5 illustrates the shift of gasoline volumes from service stations to the convenience stores and pumper formats over the period 1988-1999.[37]

Today, the convenience store is by far the most common retail gasoline format.[38] The National Association of Convenience Stores estimates that about 76% of the gasoline sold at retail in the United States in 2002 was purchased at convenience stores.[39] The largest convenience store companies (those with over 200 convenience outlets) currently operate stores with an average of 2,314 square feet of in-store space, have an average of eight MPDs per site, and sell an average of 119,580 gallons of fuel per month per site.[40]

Another new class of high-volume competitor, the hypermarket, has entered gasoline retailing. Hypermarkets – grocery stores, mass-merchandise retailers, membership clubs, and grocery supermarkets – emerged as gasoline retailers during the late 1990s and captured more than 5% of the U.S. retail gasoline sales in only five years, becoming particularly important sources of retail gasoline in certain areas. The new high-volume, low-price retail outlets may be important competitive constraints on branded marketers' ability to raise prices in some areas, because the branded marketers will lose sales if consumers switch to the new outlets.[41] Hypermarkets are discussed in more detail in Section II.F.

D. State-Level Concentration Trends in Gasoline Marketing

Public data are unavailable regarding concentration trends in appropriately defined relevant antitrust markets for gasoline marketing. However, EIA state-level data are

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36 Bob Frei & Jim Peters, *New Millennium gasoline retailing: Challenge to the incumbents*, NATIONAL PETROLEUM NEWS 54 (May 2000). *See also* William J. McAfee, *From "Circle Service" to Do-It-Yourself: 1950s to Today*, NATIONAL PETROLEUM NEWS 66 (May 2002).

37 *National Petroleum News Factbook* defines convenience stores as facilities with retail space exceeding 600 square feet, the primary business of which is the sale of food items, and having fewer than six nozzles. Pumpers are facilities having more than six nozzles with a volume exceeding a set limit, typically 50,000 gallons per month.

The trend toward newer formats may vary across the country, depending on local economic and regulatory conditions. For example, the inability to get zoning permits has prevented Exxon from building new retail outlets in Washington, D.C. *See* James S. Carter, Testimony in U.S. Senate, Permanent Subcommittee on Investigations of the Committee on Governmental Affairs, *Gas Prices: How Are They Really Set?* 48, 107th Cong., 2nd Sess. (Apr. 30, 2002).

38 Darren Wright, *Down, But Not Out*: *Service Station Retailers Cope With a Changing Landscape*, NATIONAL PETROLEUM NEWS 30 (Nov. 2001); *2002 Annual C-Store Survey*, NATIONAL PETROLEUM NEWS (Oct. 2002). *See also Retail Market: US Gasoline Shares by Key Categories: A Five Year Overview*, NATIONAL PETROLEUM NEWS 14 (July 1999).

39 Communication between FTC Bureau of Economics staff and National Association of Convenience Stores, February 2004.

40 Darren Wright, *supra* note 38; *2002 Annual C-Store Survey*, *supra* note 38.

41 *See* Conoco/Phillips, Analysis to Aid Public Comment (discussing the competitive significance of hypermarkets).

illustrative of general trends in wholesale concentration in gasoline sales. The wholesale data encompass all sales by a wholesaler in the state, combining branded and unbranded sales. As discussed in Chapter 2, the FTC has analyzed brand-level concentration in assessing the competitive effects of a merger on marketing. Some brand-level data for selected geographic areas are available from private industry surveys. This section reviews concentration estimates based on EIA data and some private surveys.

1. *State-Level Wholesale Concentration Based on EIA Prime Supplier Volumes*

EIA data measure the sale of gasoline by "prime suppliers," firms that produce or import product (either from foreign sources or across state lines) and sell the product to jobbers, retailers, or end-users within a state.[42] These sales are sometimes referred to as "first sales into state" and represent the first change in title after the product is either produced or brought into a state. These sales explicitly represent wholesale transactions if they are made at terminal racks or on a DTW basis, or they implicitly represent wholesale transactions in instances of internal company transfers to co-op retail outlets where the product is sold to the consumer.

The EIA Prime Supplier data have three significant limitations as a basis for inferences about wholesale competition and the impacts of mergers. First, although the data are collected and reported at the state level, states typically are not relevant geographic markets for analyzing overlaps in gasoline marketing. Second, confidentiality restrictions prevent the EIA from releasing information that could provide a linkage between changes in concentration and a particular merger. While EIA data identify the top four prime suppliers in each state, data on individual firms' sales or shares of sales in a state are not available. As a result, it is difficult to determine whether changes in prime supplier concentration result from mergers rather than from new entry, growth by a successful incumbent, or exit by a failing firm. Third, EIA restructured the prime supplier survey in 1993. While the changes were important improvements, concentration data before and after 1993 are not completely comparable.[43]

Wholesale concentration estimates based on EIA Prime Supplier data are presented in Table 9-6 by state for the month of December for each year between 1994 and 2003 and for March 2004.[44] Prime suppliers at the state level in March 2004 were either unconcentrated or moderately concentrated (by Merger Guidelines standards) in all but eight states and the District of Columbia. While state-level

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[42] Kenneth I. Platto, *Changes to Form EIA-782C, Monthly Report of Petroleum Products Sold into States for Consumption*, EIA/PETROLEUM MARKETING MONTHLY 3 (1993).

[43] The 1993 changes focused on eliminating double counting. Double counting occurred when a prime supplier sold product to another prime supplier that in turn sold it to a retailer, jobber, or end-user in another state, and both prime suppliers reported the transaction. EIA in 1993 also increased the number of firms that were required to respond as prime suppliers. The data most affected by these changes were for the Gulf and New England states.

[44] Results for March 2004 represent the most recent data from EIA at the time of this report's finalization.

HHIs tended to increase between December 1994 and March 2004, these changes generally have not resulted in HHIs in the highly concentrated range. Exceptions to this general trend are Indiana, Kentucky, Michigan, North Dakota and Ohio, where HHI levels increased to the highly concentrated range. HHIs for West Virginia and Oregon increased above 1,800 at some point after 1994 but fell back to below 1994 levels by March 2004. Nebraska's HHI increased above 1800 in December 2002 before receding to within the moderately concentrated a year later.

Mergers influenced some, but not all, of the HHI changes in these states. For example, the Marathon/Ashland joint venture of 1998 probably was largely responsible for increases in concentration in Kentucky, Ohio, and Indiana between 1997 and 1998.[45] The 1999 Marathon/UDS asset acquisition appears primarily responsible for the concentration increase in Michigan between 1998 and 2000. Other mergers may have contributed to smaller increases in concentration elsewhere. It must be emphasized, however, that states are not relevant geographic markets in which to assess the competitive effects of a merger at the marketing level. Other year-to-year changes in state-level HHIs are unrelated to mergers, reflecting instead gains and losses in shares for incumbents, exits, and entries.

2. Brand-Level Concentration

Brand concentration estimates are available for selected geographic areas based on private industry surveys. Brand concentration differs from

[45] A recent merger retrospective found no evidence of anticompetitive price increases from the Marathon/Ashland joint venture on gasoline prices in Louisville, one of the main metropolitan areas in Kentucky. *See* Christopher Taylor & Daniel Hosken, *The Economic Effects of the Marathon-Ashland Joint Venture: The Importance of Industry Supply Shocks and Vertical Market Structure* (2004) (FTC Working Paper). This retrospective compared price changes at both the wholesale and retail levels in this merger-affected market with prices changes in carefully selected comparable, but non-merger-affected, markets. Such an approach, called an "event study," is superior to price-concentration studies, which attempt to determine the effects of a merger through estimating price-concentration relationships. Price-concentration studies suffer from significant methodological weaknesses; they may also suffer from exclusion of significant data as well. Any reliable price-concentration analysis necessarily requires that concentration be calculated in an economically well defined market, and must take account of the effects on price of factors unrelated to a merger. Isolating the effects on price from a merger requires the correct and comprehensive identification of factors that might influence demand (*e.g.*, seasonality, temperature, income) as well as those that might influence supply (*e.g.*, supply disruptions, changes in gasoline formulation). Changes in market share or concentration occur for reasons unrelated to mergers, and may be a function of the competitive process. (The structure of the gasoline industry adds further complicating factors. A merger can raise rack prices but retail prices may go down; that is, a rack price increase is not a necessary and sufficient criterion for determining possible anticompetitive effects of a merger.) For a discussion of the methodological weaknesses, *see* W. Evans, Luke Froeb & Greg Werden, *Endogeneity in the Concentration-Price Relationship: Causes, Consequences, and Cures*, 41 J. INDUS. ECON. 431 (1993);Timothy Bresnahan, *Empirical Studies of Industries with Market Power*, in II HANDBOOK OF INDUSTRIAL ORGANIZATION 1011 (1989) (R. Schmalensee and R. Willig, eds.). *See also* FTC Energy and Commerce Committee Statement, Appendix. While price-concentration studies were once a focus in the economics literature on market structure and industry competitiveness, these studies have largely been abandoned in favor of analyses such as merger event studies that attempt to model more directly and with more precision the effects of structural change (such as a merger) upon prices. For a review of some of the empirical studies attempting to measure the impact of a merger on gasoline prices, *see* John Gewecke, *Empirical Evidence on the Competitive Effects of Mergers in the Gasoline Industry*, *supra* note 22.

wholesale marketer concentration because (1) wholesale share for a marketer reflects sales by the marketer for both its branded and unbranded retail outlets, and (2) some marketers have a retail brand presence and no wholesale presence, while others have a wholesale presence and no retail presence in particular geographic areas. Two private data sources are considered here: NPD Group's Motor Fuels Index (state level) and MPSI Systems, Inc. ("MPSI") (city level).

NPD's Motor Fuels Index is based on monthly survey data on consumers' most recent gasoline purchases.[46]

Table 9-7 presents brand-level HHIs for each state for selected years between 1987 and 2002. Brand-level concentration was below 1,500 in all but 8 states in 2002 and was below 1,800 in 4 of those states. While state-level brand concentration has generally risen since 1987, it remains moderate for most states. (As with state-level EIA Prime Supplier data, NPD's state-level brand concentration data may not accurately reflect concentration in any appropriately defined antitrust market.)

Mergers among the major oil companies contributed to increases in state-level concentration levels in some states, but the levels of concentration remained relatively low. For example, BP's merger with Amoco in late 1998 and (to a lesser extent) the joint venture between Shell, Texaco, and Saudi Refining in mid-1998 contributed to an increase in brand-level concentration in Georgia in the late 1990s.[47] Marathon Ashland's 1999 acquisition of the former Total assets from UDS likely accounts for most of the concentration increase in Michigan. Similarly, the marketing joint venture between Marathon and Ashland in 1998 likely accounts for most of the concentration increase in Ohio over the period.[48] Despite the increased state-level concentration in Georgia, Michigan, and Ohio, concentration remains relatively low in those states and has declined in recent years.

Market share and concentration levels may change for reasons other than merger activity. For example, a significant amount of the increased concentration in Georgia was attributable to the growth of private-

[46] More specifically, NPD takes a monthly sample of 30,000 households selected from a pool of 400,000 households. A different sample of 30,000 is used each month until all 400,000 households are surveyed. This yields over 200,000 completed consumer gasoline purchase behavior questionnaires per year on a national basis. Because NPD data are collected and typically reported by brand, aggregation is required to account for firms that own multiple brands. Furthermore, the rights to the same brand may be controlled by different companies in different parts of the country. For example, from 1993 until 1999, BP-branded gasoline stations in Washington and Oregon were associated with Tosco, rather than BP, because Tosco had the exclusive license to the BP brand in those states. This does not imply that Tosco owned all of the BP sites in Washington and Oregon; many were jobber-owned. Nonetheless, for those stations not owned by Tosco, the retailers' wholesale supply contracts were with Tosco, not BP.

[47] There were no retail marketing divestitures in Georgia associated with the Shell/Texaco/Saudi Refining joint venture, but the FTC required substantial retail divestitures in Georgia in connection with the BP/Amoco merger. BP and Amoco had to give their jobbers and open dealers the option of canceling their franchise and supply agreements without penalty in Albany, Athens, Columbus, and Savannah, Georgia. In addition, BP Amoco was required to sell all company-owned BP or Amoco stations in Savannah.

[48] Neither of these states was reclassified as a result of the concentration increases between 1996 and 2002.

brand marketers. Similarly, while the 1997 Equilon joint venture between Shell and Texaco contributed to somewhat higher levels of concentration in Oregon, the largest factor affecting brand concentration in the state was the steady increase in Chevron's retail market share since the early 1990s. Wisconsin's HHI increased 296 points between 1996 and 2002 largely as a result of growth by Citgo, not mergers. Montana's HHI increased between 1990 and 1992 because of market growth by Conoco and Cenex/Ampride, and again from 1992 to 1994 from continued growth by Conoco in the state. The increased concentration in the District of Columbia during the mid-1990s was primarily the result of growth by Amoco. The more recent decline in the District's HHI is attributed to BP Amoco's loss of market share. In North Dakota, the state-wide HHI increased noticeably between 1990 and 1992 and again between 1996 and 1998, followed by significant declines between 2000 and 2002. Both episodes of increasing concentration appear to be attributable to market share growth by Amoco and Cenex/Ampride. The more recent decline in North Dakota's HHI is primarily attributable to BP Amoco's loss of market share in the state.

A second source of data for brand concentration data is MPSI. These data, presented in Table 9-8, provide insights on brand concentration trends in 13 selected cities across the U.S. for two years.[49] In addition to HHIs based on total volume shares, the table lists the top five retailers in each market and the average monthly volume per outlet for the top five brands. Though increasing some between 1990 and 2001, the concentration levels in these 13 cities have for the most part remained below 1,500. The three West Coast cities were exceptions: San Francisco, Seattle, and Los Angeles had brand-level concentration somewhat above 1,800.

E. Entry into Gasoline Marketing

As assessment of whether entry by marketers would prevent or offset anticompetitive effects from a merger of two incumbent brands requires consideration of entry conditions at both wholesale and retail levels. An entering marketer needs to obtain reliable bulk supplies and terminal services as well as a reliable outlet for product. Some entrants may secure bulk supply directly from refineries under f.o.b. contracts, taking title at the refinery gate and arranging for transportation and terminal services; others may arrange for supply at the terminal level from another marketer (often a refiner) under various types of contracts, including product exchanges.

Access conditions for bulk supply and terminals vary across the nation and can vary seasonally. Their importance as potential impediments to marketing entry in the context of a

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[49] Unlike NPD's retail data, which are based on consumer survey responses, the MPSI retail information is based on a physical survey of retail assets within a market. While MPSI data are likely to be more precise than NPD data, because the MPSI data are based on a physical accounting of assets, the market coverage and frequency of MPSI data are limited. The 13 cities discussed here represent a sample of large metropolitan areas representing all regions of the U.S. for which MPSI conducted market surveys in or around 1990, and again in or around 2000.

particular merger depends on case-specific factual circumstances. For example, while multiple independent pipelines or public terminals serve some regions of the country, other regions are more isolated and may be supplied by a small number of proprietary pipelines and terminals. Entry may be easier in the first case because more options are available and because pipeline and terminal owners do not have an incentive to withhold services from an entrant to protect their own marketing operations. In areas served by common carrier pipelines, an entrant may need only to meet minimum pipeline tender requirements, assuming that unutilized pipeline and terminal capacities exist.[50]

An entering marketer also needs to obtain retail distribution. An entrant into marketing may secure retail outlets either by inducing incumbent jobbers or open dealers to switch brands or by building new stations of its own. An entrant needs access to enough retail outlets to achieve sufficient distributional and promotional scale economies to assure successful entry in a particular geographic area. The costs of recruiting existing jobbers and open dealers will depend on their relationships with incumbent wholesalers. Jobbers with their own stations or independent open dealers that have contractual commitments to carry an incumbent's brand may be persuaded to switch to the entrant. In some instances, the entrant may need to cover the costs that retail stations would incur from breaking existing contractual relationships. These costs can vary considerably across jobbers or open dealers.[51]

An entrant could also secure retail sales by building its own retail sites or supporting site construction by its prospective customers. A typical retail gasoline outlet with a convenience store can be built in under one year for a cost of $1 million to $1.5 million. A high-volume gasoline store at an existing hypermarket capable of selling three to five times as much gasoline as a traditional station[52] can be constructed in only a few months for as little as $500,000.[53] As noted above, depending on the area, an entrant may need multiple stations to achieve sufficient

[50] Minimum shipments on a common-carrier pipeline are on the order of 5,000 to 10,000 barrels of product of the same specification. Even with inline mixing at terminals, minimum pipeline requirements might be large relative to demand in smaller relevant geographic markets. But even in these cases, an entrant may be able to pool volumes with other marketers or negotiate to receive products on exchange with an incumbent wholesaler at the terminal.

[51] In addition to image discounts, branded retailers may also receive Temporary Competitive Allowances or Temporary Volume Allowances ("TVAs"). These are both short-term wholesale volume discounts typically offered in local markets experiencing increased competition associated with new entry. As with other contracts, the retailer must repay TVAs if it leaves the wholesaler's brand before a specified period (one to two years). As a result, if a retailer with an image contract switches wholesalers, the retailer bears a switching cost. Switching costs associated with breaking image contracts will be higher in markets where incumbent marketers have recently entered into image agreements to finance retail outlet builds or improvements.

[52] For example, the average monthly volume for seven Costco hypermarket fuel sites in 2001 was over 400,000 gallons per site. *Petroleum Market Evaluator: San Diego, CA* (2001) (OPIS & New Image Marketing, Rockville, MD). Some of the highest-volume hypermarkets are able to throughput volumes of roughly 1,000,000 gallons per month.

[53] *Hypermarket Fears Echoed in the Canyon at SIGMA*, NATIONAL PETROLEUM NEWS 17 (July 1, 2001). *See also* Beth Evans, *Petrodollars*, PLATT'S OILGRAM NEWS (Dec. 2, 2002).

distributional and promotion scale for successful entry. Differences in entry conditions may also arise because of regional variations in zoning and permitting. More stringent zoning and permitting rules increase site search costs and delay new entry.

Entry into a local geographic area also involves costs related to branding. Branding costs can take a variety of forms, from general advertising within a local market to subsidizing independent retail outlets' investments in the entrant's brands through image loans. Such branding costs, of course, would not apply to a firm entering only at the wholesale, unbranded rack level.

F. The Rise of Hypermarkets

Hypermarkets are large retailers of general merchandise and grocery items, such as grocery supermarkets, mass merchandisers, and club stores. By the fourth quarter of 2002, roughly five years after they began selling gasoline in the U.S., hypermarkets had captured 5.9% of the retail gasoline sales nationwide. Hypermarkets are projected to account for 13.1% of the nation's retail gasoline sales by 2007 (based on planned expansions by existing hypermarketers).[54] Hypermarkets' ability to obtain this share of sales in a short period is particularly impressive considering that the 2,440 hypermarkets account for roughly 1.3% of all gasoline sites in the U.S. Some of the larger hypermarket sites sell 500,000 to 1,000,000 gallons of fuel in a month, five to ten times the volume of a typical gasoline retailer.

The success of the larger hypermarkets stems from the fact that they sell significantly higher volumes of gasoline at lower prices than their competitors. One reason hypermarkets can underprice more traditional retailers is that the costs associated with constructing and operating hypermarket sites are considerably lower than those of other gasoline retailers. In addition to enjoying lower construction and operating costs, hypermarketers may be willing to sell gasoline at smaller margins as part of a loss-leader or similar marketing strategy.

Building a gasoline outlet at a hypermarket location is typically significantly less costly than constructing a modern convenience store gasoline site. The hypermarket usually constructs a relatively small fuel site, or "pad", occupying only about 300 to 600 square feet of the hypermarket's parking lot.[55] These sites often consist of little more than a canopy, a kiosk, and several MPDs capable of through-putting in excess of 500,000 gallons of gasoline a month. They can usually be constructed for about $650,000[56] (and sometimes for as little as $500,000).[57] This is significantly less than the typical cost of $1 million to $1.5 million associated

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54 *Industry*, CONVENIENCE STORE NEWS (June 6, 2003). *See also Evolution of the High Volume Retailer: Response to Requests for Information*, ENERGY ANALYSTS INTERNATIONAL (Feb. 13, 2003) (Westminster, CO).

55 William Morris, *Comparison Between Typical Petroleum Marketers' and Hypermarketers' Approach to New Builds*, NATIONAL PETROLEUM NEWS 76 (Oct. 2002).

56 *Id.* at 77.

57 *Hypermarket Fears Echoed in the Canyon at SIGMA*, *supra* note 53.

with constructing a modern convenience store.[58]

Moreover, operating costs for hypermarket fuel sites are often lower than the costs associated with operating convenience stores. Some hypermarkets keep operating cost down by operating unattended fuel sites. Like other high-volume retailers, hypermarket retailers are more likely to attain cost savings on their wholesale gasoline supplies compared to typical non-integrated marketers.

Table 9-9 summarizes the growth of hypermarkets by state. Except for the Northeast, hypermarkets appear to have made significant inroads into gasoline retailing throughout the U.S. Hypermarkets have experienced particularly rapid growth and have significant shares of sales in Arkansas, Kentucky, Tennessee, Texas, and Washington State. Although many of the smaller regional grocery store chains are becoming gasoline retailers, the hypermarket category of gasoline retailers is dominated by the large national grocery chains, mass merchants, and membership clubs. While approximately 40 hypermarket retailers currently sell gasoline, over 80% of their total sales of gasoline are accounted for by eight chains, including grocery stores (Albertson's, HEB, Kroger, Meijer, Safeway), a mass merchant (Wal-Mart), and membership clubs (Costco, Sam's).[59]

Hypermarkets have expanded in areas of the country (such as Texas) where bulk supply options are relatively abundant and where local real estate and zoning are likely to be relatively favorable. Yet hypermarkets have also successfully entered and captured substantial market share in regions where bulk supply conditions generally have been thought to be less favorable. For example, hypermarket expansion is above the national average in PADD V, a region characterized by relatively tight bulk supply conditions. Costco entered San Diego in 1999 with a single fuel site and by 2000 had seven retail fuel sites at Costco club stores. With just these fuel sites (which represented 1% of the gasoline outlets in San Diego), Costco captured 3.1% (or roughly 3 million gallons per month) of retail gasoline sales by 2000.[60]

58 William Morris, *supra* note 55, at 77.

59 According to Paul Leto, *Special Report: Hypermarket Fuel Sales*, CONVENIENCE STORE NEWS (June 6, 2003), over three-quarters of the 2,440 hypermarket locations are controlled by the "Big Seven": Albertson's, Kroger, Safeway, Costco, Sam's Club, Wal-Mart, and Meijer. The top eight hypermarketers, which consists of the "Big Seven" as well as grocer HEB, account for over 80% of hypermarket gasoline sales. *See* Joseph Tarnowski, *Supermarket NONFOODS Business: Older and Wiser*, PROGRESSIVE GROCER (Feb. 15, 2003). *See also* Joseph Tarnowski, *Older and Wiser*, CSNEWS ONLINE (http://www.CSNews.com),Oct. 6, 2002); *Evolution of the High Volume Retailer: Response to Requests for Information*, *supra* note 54.

60 *Petroleum Market Evaluator*, *supra* note 52.

Table 9-1 – Petroleum Product Terminals

Region		Total Bulk Terminals Establishments				Refiner-Marketer Terminals				Other Terminals			
		1982	1987	1992	1997	1982	1987	1992	1997	1982	1987	1992	1997
US	Total	2293	1626	1378	1225	1211	973	872	667	1082	653	506	558
	%chg		-29	-15	-11		-20	-10	-24		-40	-23	10
PADD I	Total	880	648	542	453	546	400	324	250	334	248	218	203
	%chg		-26	-16	-16		-27	-19	-23		-26	-12	-7
PADD I-A	Total	127	89	78	72	70	43	29	22	57	46	49	50
	%chg		-30	-12	-8		-39	-33	-24		-19	7	2
PADD I-B	Total	419	296	238	195	268	174	135	109	151	122	103	86
	%chg		-29	-20	-18		-35	*-22*	-19		-19	-16	-17
PADD I-C	Total	334	263	226	186	208	183	160	119	126	80	66	67
	%chg		-21	-14	-18		-12	-13	-26		-37	-18	2
PADD II	Total	669	450	380	314	292	264	250	201	377	186	130	113
	%chg		-33	-16	-17		-10	-5	-20		-51	-30	-13
PADD III	Total	350	269	232	221	138	138	153	111	212	131	79	110
	%chg		-23	-14	-5		0	11	-27		-38	-40	39
PADD IV	Total	95	46	34	42	23	24	20	20	72	22	14	22
	%chg		-52	-26	24		4	-17	0		-69	-36	57
PADD V	Total	299	213	190	195	212	147	125	85	87	66	65	110
	%chg		-29	-11	3		-31	-15	-32		-24	-2	69

Source: U.S. Census Bureau, *Economic Census of Wholesale Trade: Subject Series*, tables entitled: "Petroleum Bulk Stations by Type of Stations for States" and "Bulk Storage Capacity by Type of Product for States" (1982, 1987, 1992, 1997).

Table 9-2 – Refiner Disposition of Gasoline by Class of Trade
1994-2002
(% by Class)

Total Gas Volume by All R&G		US	PADD I	I-A	I-B	I-C	II	III	IV	V
1994	Co-op	17.5	13.6	5.6	13.2	15.7	21.4	16.1	22.8	18.3
	DTW	27.5	33.0	42.1	47.2	20.2	17.8	8.9	12.8	53.7
	Rack	55.0	53.3	52.4	39.6	64.1	60.8	75.0	64.4	28.0
	Total Vol. (Mgal/d)	301,754	99,579	11,029	38,458	50,093	91,347	48,244	9,585	52,999
1995	Co-op	17.5	13.4	5.5	12.9	15.4	20.9	16.6	22.5	19.4
	DTW	25.4	30.1	40.8	44.8	16.6	16.6	7.2	9.5	51.8
	Rack	57.0	56.6	53.7	42.3	68.0	62.5	76.3	68.0	28.8
	Total Vol. (Mgal/d)	306,484	101,235	11,157	38,801	51,277	94,672	47,136	10,520	52,921
1996	Co-op	17.8	13.6	6.1	13.5	15.2	20.6	17.9	22.4	19.8
	DTW	25.1	29.0	41.3	43.4	15.7	15.9	6.7	10.0	52.8
	Rack	57.1	57.4	52.6	43.1	69.0	63.5	75.4	67.6	27.3
	Total Vol. (Mgal/d)	309,439	101,570	10,896	38,597	52,077	94,805	47,919	10,802	54,343
1997	Co-op	18.7	14.3	6.3	13.6	16.4	20.9	18.9	22.7	22.4
	DTW	24.0	28.0	39.8	42.4	15.0	15.2	6.3	9.5	51.3
	Rack	57.3	57.7	53.8	44.0	68.5	63.8	74.8	67.8	26.2
	Total Vol. (Mgal/d)	313,416	104,670	11,111	39,407	54,152	96,200	48,638	11,103	52,805
1998	Co-op	19.2	15.4	6.7	13.8	18.2	20.6	18.4	23.1	23.9
	DTW	22.8	27.0	39.6	41.3	14.3	12.0	5.8	9.7	50.8
	Rack	58.1	57.6	53.7	44.9	67.5	67.4	75.8	67.2	25.3
	Total Vol. (Mgal/d)	320,449	107,309	11,152	40,134	56,023	96,858	49,391	11,007	55,884
1999	Co-op	18.4	15.2	7.0	13.4	18.1	17.9	18.8	23.7	23.9
	DTW	22.1	26.7	39.2	41.6	13.7	11.8	4.6	8.5	49.4
	Rack	59.5	58.1	53.8	45.0	68.2	70.4	76.6	67.8	26.6
	Total Vol. (Mgal/d)	326,887	107,469	11,187	39,766	56,516	98,797	51,396	11,618	57,607
2000	Co-op	18.1	16.6	12.0	15.6	18.2	16.3	18.2	23.3	24.1
	DTW	21.3	25.3	36.1	40.3	12.7	10.1	3.7	9.3	50.3
	Rack	60.6	58.1	51.9	44.1	69.1	73.5	78.1	67.4	25.6
	Total Vol. (Mgal/d)	326,435	108,883	11,351	39,920	57,612	98,845	49,736		
2001	Co-op	18.4	17.1	13.7	16.8	18.0	16.4	19.1	21.3	22.8
	DTW	20.5	24.4	34.4	40.2	11.6	8.9	3.1	7.7	50.1
	Rack	61.1	58.5	51.9	43.0	70.4	74.6	77.9	71.0	27.2
	Total Vol. (Mgal/d)	328,844	109,735	11,884	39,542	58,309	98,382	50,194	11,808	58,725
2002	Co-op	18.8	17.6	13.9	17.4	18.5	17.0	18.3	19.9	23.7
	DTW	20.2	24.7	33.1	41.8	11.2	7.9	2.8	8.4	49.2
	Rack	61.0	57.7	53.0	40.8	70.3	75.1	78.9	71.7	27.0
	Total Vol. (Mgal/d)	330,594	110,150	12,073	39,974	58,103	98,238	51,156		

Source: EIA *Form 782-A*, “Refiners'/Gas Plant Operators' Monthly Petroleum Products Sales Report” (monthly).

Notes: Co-op (direct supply to company-operated stations); DTW (dealer tankwagon distributed); Rack (rack distributed); 2000 annual DTW data withheld for PADDs IV, V; February 2000 data are used as a proxy. 2002 annual DTW data withheld for PADDs IV, V; June, August, October 2002 data are used as a proxy.

Table 9-3 – Retail Gasoline Station Count

State	1991-1993	1994-1996	1997-1999	2000-2002
	PADD I-A			
Connecticut	1,817	1,960	1,662	1,574
Maine	1,200	1,267	1,325	1,395
Massachusetts	3,400	2,439	2,533	2,533
New Hampshire	1,016	1,007	935	913
Rhode Island	616	528	525	519
Vermont	853	785	764	870
	PADD I-B			
Delaware	469	478	513	411
Dist. of Col.	166	106	114	135
Maryland	2,303	2,404	2,370	2,362
New Jersey	3,867	3,989	3,867	3,828
New York	6,917	6,784	6,375	6,070
Pennsylvania	6,597	6,000	5,167	4,772
	PADD I-C			
Florida	10,071	9,312	9,292	9,431
Georgia	7,409	7,957	7,529	7,682
North Carolina	10,109	8,606	8,099	7,439
South Carolina	4,858	4,378	4,451	3,993
Virginia	6,133	6,525	5,747	5,034
West Virginia	2,628	2,090	2,000	2,000
	PADD II			
Illinois	7,075	5,371	4,976	4,625
Indiana	4,077	3,482	3,324	3,234
Iowa	4,151	3,051	3,140	3,002
Kansas	2,916	2,760	2,610	2,481
Kentucky	2,935	4,903	4,263	3,956
Michigan	6,968	4,898	5,372	5,208
Minnesota	3,418	3,333	4,044	3,689
Missouri	6,218	5,442	5,082	4,736
Nebraska	2,355	1,899	2,165	1,736
North Dakota	1,122	992	918	903
Ohio	6,127	6,090	6,109	5,873
Oklahoma	4,983	4,725	4,105	3,897
South Dakota	1,228	1,367	1,600	1,268
Tennessee	5,900	5,375	5,235	4,971
Wisconsin	4,571	4,135	3,947	3,521
	PADD III			
Alabama	6,250	6,444	5,297	4,667
Arkansas	3,625	3,357	3,172	2,985
Louisiana	8,532	9,092	7,267	6,066
Mississippi	5,876	4,188	3,855	3,745
New Mexico	1,861	1,705	1,650	1,437
Texas	12,300	14,963	14,974	15,700

Table 9-3 *(continued)*

State	1991-1993	1994-1996	1997-1999	2000-2002
	PADD IV			
Colorado	4,394	3,727	2,360	2,218
Idaho	974	1,349	1,035	885
Montana	1,377	1,379	1,518	1,333
Utah	2,123	1,886	1,305	1,122
Wyoming	1,099	664	417	533
	PADD V			
Alaska	286	270	262	372
Arizona	2,835	3,089	1,927	2,188
California	13,789	14,200	12,239	10,169
Hawaii	397	409	385	424
Nevada	635	805	833	920
Oregon	2,084	1,838	1,868	1,795
Washington	3,752	2,391	3,167	3,077
Total U.S.	206,660	196,193	183,685	173,697

Source: *National Petroleum News Market Facts* (annual). Data from *National Petroleum News* are used with permission.

Note: Station counts within periods based on average of individual years.

Table 9-4 – Retail Gasoline Volumes & Volume per Outlet

Area	2001	2000	1999	1998	1997	1996	1995	1994
	Total Volume (1000's gal/day)							
Total U.S.	361,724	353,900	359,084	352,592	344,196	339,463	335,842	329,181
PADD I	128,579	123,869	125,687	123,938	122,246	120,316	119,445	116,937
PADD II	103,892	104,074	105,030	102,109	100,516	99,041	98,517	95,735
PADD III	53,797	52,263	54,416	52,828	50,980	50,534	49,768	49,102
PADD IV	12,346	12,143	12,275	11,920	11,693	11,405	11,043	10,591
PADD V	63,111	61,551	61,676	61,796	58,762	58,167	57,069	56,815
	Volume/Outlet (gal/month)							
Total U.S.			94,559	88,184	86,360	84,503	82,129	78,752
Northeast			90,195	84,576	82,789	80,358	78,834	77,291
Midwest			96,695	93,870	91,227	88,368	87,564	82,563
Sunbelt			81,222	76,919	74,921	72,709	69,858	64,008
West			125,199	109,645	108,373	108,504	104,367	103,919
Total U.S.			94,559	88,184	86,360	84,503	82,129	78,752

Sources: Total volumes from EIA, *Form 782-C*, "Prime Supplier Sales" (monthly); volume per outlet data from *National Petroleum News Market Facts* (annual). Data from *National Petroleum News* are used with permission.

Table 9-5 – Retail Format Comparison

	Service Station			C-store & Pumpers			Total
		Market Share (%)			Market Share (%)		
Year	Volume (gal/mo.)	Sites	Volume	Volume (gal/mo.)	Sites	Volume	Volume (gal/mo.)
1988	58,021	42.2	39.3	81,690	47.2	57.7	66,740
1989	61,669	39.8	37.7	84,017	49.7	59.7	70,023
1990	62,479	38.4	36.4	83,799	51.5	61.0	69,036
1991	68,972	38.0	35.6	86,245	52.4	62.0	73,255
1992	70,398	36.9	34.9	87,163	53.7	62.8	74,495
1993	71,660	36.5	34.4	88,856	54.4	63.4	76,098
1994	73,850	35.3	33.1	91,521	55.8	64.9	78,752
1995	75,850	33.4	30.8	95,230	58.1	67.4	82,129
1996	77,659	31.6	29.1	97,099	60.2	69.2	84,503
1997	77,603	30.8	27.7	99,573	61.2	70.5	86,360
1998	78,352	29.3	26.0	101,159	62.9	72.2	88,184
1999	83,048	26.9	23.7	106,834	66.0	74.6	94,559

Source: *National Petroleum News Market Facts*, “U.S. Gasoline Shares by Key Categories” (annual). Data from *National Petroleum News* are used with permission.

Note: C-store and pumper volume data represent site-number-weighted average of volumes reported separately by *National Petroleum News* for C-stores and pumpers. Shares reported herein do not add to 100% because of omission of data from other minor retail formats such as automobile dealers and parking garages.

Table 9-6 – Wholesale Concentration Estimates (HHI Measure)

State	Dec-94	Dec-95	Dec-96	Dec-97	Dec-98	Dec-99	Dec-00	Dec-01	Dec-02	Dec-03	Mar-04
						PADD I-A					
Connecticut	1,089	1,153	1,262	1,257	1,490	1,320	1,433	1,487	1,494	1,514	1,394
Maine	1,208	1,288	1,336	1,435	1,448	1,465	1,409	1,436	1,429	1,468	1,550
Massachusetts	937	1,104	1,165	1,132	1,329	1,155	1,265	1,270	1,321	1,474	1,432
New Hampshire	777	893	922	837	878	1,019	972	959	1,000	1,163	1,154
Rhode Island	1,046	1,142	1,127	1,148	1,496	1,483	1,478	1,669	1,743	1,736	1,512
Vermont	1,163	1,202	1,105	1,154	1,162	1,118	1,183	1,274	1,152	1,264	1,153
						PADD I-B					
Delaware	876	894	928	947	1,124	1,145	1,093	1,258	1,199	1,453	1,628
Dist. of Col.	3,374	3,505	3,233	3,130	3,503	3,459	2,948	2,914	3,041	2,616	2,552
Maryland	1,142	1,117	1,080	1,104	1,242	1,139	1,314	1,168	1,191	1,258	1,185
New York	1,064	1,112	1,121	1,075	1,167	1,039	1,020	1,017	1,022	1,098	1,036
New Jersey	816	876	904	905	1,044	1,027	1,135	1,075	1,151	1,149	1,240
Pennsylvania	1,024	933	1,059	923	1,008	1,148	1,256	1,344	1,370	1,429	1,612
						PADD I-C					
Florida	869	869	871	803	948	1,036	1,125	1,067	1,032	994	1,019
Georgia	720	741	725	706	819	1,135	1,117	1,112	1,137	1,176	1,169
North Carolina	847	916	922	871	1,014	1,142	1,220	1,140	1,166	1,215	1,178
South Carolina	829	855	840	839	906	964	1,020	1,142	1,045	1,013	991
Virginia	893	979	894	968	1,083	1,125	1,172	1,148	1,128	1,148	1,086
West Virginia	1,573	1,412	1,564	1,645	2,621	2,318	1,982	1,792	1,559	1,511	1,390
						PADD II					
Illinois	1,154	1,195	1,162	1,283	1,228	1,275	1,253	1,307	1,370	1,316	1,272
Indiana	1,589	1,747	1,721	1,845	1,985	1,915	1,761	2,258	2,213	2,140	2,303
Iowa	744	830	772	918	838	943	831	896	1,127	1,122	910
Kansas	880	939	906	882	976	972	988	1,086	1,655	1,557	1,343
Kentucky	1,412	1,329	1,406	1,477	2,263	1,945	2,128	2,238	2,141	2,403	2,492
Michigan	1,173	1,181	1,153	1,174	1,279	1,709	1,841	1,828	1,975	1,916	2,017
Minnesota	1,203	1,248	1,203	1,303	1,272	1,408	1,311	1,384	1,523	1,404	1,368
Missouri	724	852	873	859	940	921	916	902	1,277	1,283	1,328
Nebraska	897	892	837	923	961	919	941	1,264	1,836	1,669	1,445
North Dakota	1,605	1,993	1,904	1,911	2,146	2,555	2,049	2,016	2,213	2,539	2,496
Ohio	1,576	1,481	1,514	1,591	2,070	2,135	2,044	1,983	2,012	1,971	2,025
Oklahoma	922	1,016	971	1,020	909	926	1,000	945	1,459	1,315	1,335
South Dakota	812	941	864	879	964	914	965	1,149	1,416	1,204	1,176
Tennessee	770	836	836	848	1,060	1,207	1,275	1,234	1,267	1,251	1,245
Wisconsin	975	1,028	993	1,231	1,160	1,184	1,217	1,310	1,349	1,352	1,307

Table 9-6 *(continued)*

STATE	Dec-94	Dec-95	Dec-96	Dec-97	Dec-98	Dec-99	Dec-00	Dec-01	Dec-02	Dec-03	Mar-04
						PADD III					
Alabama	719	754	829	812	1,088	1,180	1,188	1,204	1,145	1,136	1,143
Arkansas	674	646	617	684	815	816	907	868	935	977	975
Louisiana	924	929	951	939	1,145	1,180	1,129	1,142	1,234	1,160	1,203
Mississippi	735	765	805	787	967	1,062	1,052	1,039	1,077	1,046	960
New Mexico	940	1,025	1,072	1,158	1,296	1,390	1,231	1,320	1,423	1,465	1,475
Texas	763	874	850	863	1,056	1,038	1,027	1,043	1,132	1,138	1,145
						PADD IV					
Colorado	1,024	1,063	1,064	1,331	1,312	1,292	1,323	1,287	1,795	1,395	1,369
Idaho	1,264	1,248	1,128	1,058	1,065	1,225	1,146	1,122	1,267	1,277	1,240
Montana	2,306	2,306	2,235	2,026	2,275	2,008	2,373	2,404	2,264	2,234	2,175
Utah	1,220	1,186	1,171	1,178	1,369	1,379	1,339	1,248	1,545	1,529	1,439
Wyoming	1,138	1,089	967	1,005	1,329	1,349	1,412	1,344	1,481	1,287	1,283
						PADD V					
Alaska	2,485	2,618	2,650	2,832	2,776	2,664	2,717	2,833	2,714	2,918	3,015
Arizona	1,062	1,112	1,093	1,629	1,386	1,316	1,248	1,133	1,186	1,058	1,074
California	1,145	1,198	1,226	1,445	1,547	1,648	1,514	1,540	1,594	1,601	1,538
Hawaii	2,520	2,592	2,324	2,339	2,712	2,920	2,958	3,136	3,139	3,365	3,451
Nevada	1,434	1,531	1,431	1,402	1,333	1,481	1,550	1,428	1,679	1,745	1,783
Oregon	1,774	1,454	1,396	1,602	1,939	1,743	1,574	1,681	1,792	1,768	1,657
Washington	1,472	1,382	1,441	1,492	1,661	1,568	1,519	1,458	1,624	1,608	1,578

Source: Concentration estimates based on EIA, *Form 782-C,* “Prime Supplier Sales” (monthly). Estimates provided to FTC staff by EIA.

Table 9-7 – State Brand-Level Concentration (HHI Measure)

State	1987	1990	1992	1994	1996	1997	1998	2000	2002
					PADD I-A				
Connecticut	1,167	1,274	1,353	1,342	1,309	1,336	1,542	1,535	1,477
Maine	1,196	1,500	1,498	1,528	1,573	1,586	1,723	1,552	1,500
Massachusetts	1,196	1,228	1,243	1,191	1,192	1,167	1,397	1,293	1,170
New Hampshire	954	1,043	1,150	1,159	1,232	1,210	1,344	1,299	1,347
Rhode Island	1,657	1,385	1,445	1,389	1,345	1,378	1,841	1,613	1,479
Vermont	2,003	1,694	1,683	1,799	2,076	1,697	2,242	2,208	2,226
					PADD I-B				
Delaware	1,353	1,571	1,315	1,243	1,073	1,062	1,283	1,203	1,697
Dist. of Col.	1,994	1,799	1,914	2,079	2,363	2,463	2,445	2,213	2,166
Maryland	1,336	1,218	1,116	1,187	1,204	1,178	1,308	1,176	1,097
New Jersey	1,049	1,113	1,086	1,019	998	987	1,166	1,018	951
New York	1,162	1,175	1,231	1,204	1,272	1,293	1,297	1,311	1,263
Pennsylvania	1,064	1,114	1,103	922	883	851	905	981	1,025
					PADD I-C				
Florida	716	805	882	972	913	921	1,137	1,121	1,022
Georgia	815	895	947	931	853	934	968	1,310	1,217
North Carolina	922	984	937	1,004	1,078	1,107	1,252	1,486	1,286
South Carolina	830	1,054	1,019	979	993	948	1,061	1,201	1,010
Virginia	969	1,007	1,030	1,051	1,082	1,104	1,227	1,116	1,040
West Virginia	1,729	1,600	1,447	1,401	1,364	1,306	1,240	1,294	1,230
					PADD II				
Illinois	1,152	1,084	1,196	1,097	1,052	1,068	1,145	1,069	1,067
Indiana	1,035	1,103	1,133	1,250	1,333	1,308	1,388	1,364	1,299
Iowa	914	887	827	945	982	920	898	824	844
Kansas	815	1,058	1,162	1,026	1,170	1,150	1,125	1,146	1,037
Kentucky	1,047	1,123	1,148	1,220	1,235	1,225	1,483	1,353	1,108
Michigan	838	942	1,025	1,015	1,023	1,036	1,054	1,382	1,280
Minnesota	983	939	936	916	944	927	1,037	1,016	976
Missouri	776	865	976	913	897	899	1,048	1,072	991
Nebraska	828	1,106	1,073	1,040	1,029	1,072	1,221	1,184	1,001
North Dakota	1,822	1,535	2,276	2,236	2,449	2,131	2,749	2,581	1,627
Ohio	1,438	1,317	1,396	1,299	1,263	1,330	1,627	1,584	1,549
Oklahoma	1,260	1,333	1,321	1,267	1,308	1,427	1,427	1,421	1,238
South Dakota	1,186	1,159	1,069	1,024	1,087	1,157	1,270	1,243	1,177
Tennessee	1,048	1,038	966	934	995	976	1,139	1,365	1,278
Wisconsin	725	782	852	961	955	994	1,115	1,130	1,251

Table 9-7 *(continued)*

State	1987	1990	1992	1994	1996	1997	1998	2000	2002
					PADD III				
Alabama	813	871	900	1,011	971	980	1,292	1,488	1,349
Arkansas	926	1,059	934	1,056	1,030	1,067	1,287	1,346	1,279
Louisiana	1,345	1,335	1,317	1,266	1,234	1,245	1,644	1,547	1,377
Mississippi	1,006	1,018	1,010	1,133	1,111	1,111	1,573	1,499	1,352
New Mexico	728	923	1,012	1,210	1,101	1,157	1,348	1,303	1,240
Texas	1,051	1,112	1,092	1,052	1,021	1,037	1,287	1,315	1,179
					PADD IV				
Colorado	785	1,007	1,276	1,244	1,098	1,188	1,445	1,391	1,088
Idaho	721	924	1,152	1,172	1,276	1,317	1,333	1,158	1,268
Montana	1,148	1,547	2,089	2,419	2,342	2,430	2,431	2,346	2,350
Utah	671	1,075	1,065	1,243	1,419	1,386	1,602	1,360	1,457
Wyoming	639	930	962	1,249	1,309	1,272	1,590	1,559	1,359
					PADD V				
Arizona	1,281	1,434	1,557	1,486	1,470	1,528	1,474	1,254	1,148
California	1,412	1,535	1,524	1,525	1,608	1,611	1,723	1,693	1,635
Nevada	1,470	2,387	2,011	1,801	1,840	1,530	1,472	1,541	1,356
Oregon	1,221	1,426	1,673	1,775	1,567	1,641	1,914	1,879	1,904
Washington	1,041	1,205	1,457	1,574	1,605	1,679	1,791	1,835	1,430

Source: *NPD Group Motor Fuels Index* (annual). NPD data used under license.

Note: 2002 estimates based on data for the first six months of 2002. Source does not report for Alaska and Hawaii.

Table 9-8 City Brand-Level Concentration

City	Year	Avg Vol. of Top 5 Brands (gal/mo)	HHI - Volume Share	Top 5 Retailers				
Atlanta	2001	111,216	1,313	BP Amoco	Motiva	QuikTrip	Chevron	Citgo
	1990	80,843	722	Amoco	Texaco	Gulf	Shell	Chevron
Boston	2001	96,229	1,175	ExxonMobil	Motiva	Sunoco	Tosco	Citgo
	1991	70,726	1,127	Mobil	Shell	Sunoco	CF/Gulf	Texaco
Chicago	2001	128,481	1,289	BP Amoco	Equilon	Marathon-Ashland	ExxonMobil	Citgo
	1989	92,924	1,163	Amoco	Shell	Mobil	Unocal	Clark
Dallas/FW	2002	101,077	1,066	Motiva	Citgo	Chevron	ExxonMobil	RaceTrac
	1990	72,592	871	Texaco	Mobil	Chevron	Exxon	Citgo
Denver	2002	128,612	1,090	Conoco	Equilon	UDS	BP Amoco	Phillips
	1990	84,679	964	Amoco	Conoco	Vickers	Phillips	Texaco
Detroit	2001	119,971	1,491	Marathon-Ashland	ExxonMobil	BP Amoco	Sunoco	Equilon
	1993	113,832	1,172	Mobil	Shell	Amoco	Total	Speedway
Houston	2002	91,966	1,265	Chevron	ExxonMobil	Motiva	UDS	Conoco
	1989	68,112	1,131	Exxon	Chevron	Texaco	Shell	Stop N Go
Los Angeles	2000	160,810	1,829	Arco	ExxonMobil	Tosco	Chevron	Equilon
	1989	110,807	1,134	Unocal	Shell	Mobil	Arco	Chevron
New York	2002	118,803	1,425	BP Amoco	ExxonMobil	Hess	Getty	Sunoco
	1989	95,601	1,138	Amoco	Mobil	Merit	Getty	Shell
Phila-delphia	2001	120,630	1,261	Sunoco	Tosco	BP Amoco	Motiva	ExxonMobil
	1990	85,740	1,184	Sunoco	Mobil	Atlantic	Exxon	Amoco
San Francisco	2000	146,459	1,943	Equilon	Chevron	Tosco	Arco	Olympian
	1989	105,017	2,035	Shell	Chevron	Unocal	Arco	BP
Seattle	2001	115,818	1,833	Equilon	Chevron	Arco	Tosco	ExxonMobil
	1991	118,506	1,685	Arco	Texaco	Chevron	BP	Exxon
D.C.	2002	126,680	1,324	ExxonMobil	Motiva	Tosco	BP Amoco	Citgo
	1991	117,392	1,293	Exxon	Amoco	Shell	Mobil	Texaco

Source: MPSI Systems, Inc. MPSI data are used under license.

Table 9-9 Hypermarket Growth by State

State	Hypermarket Share within State (%)					
	1997	1998	1999	2000	2001	Jun-02
	PADD I-A					
Connecticut	0.1	0.0	0.1	0.0	0.1	1.5
Maine	2.1	0.0	1.6	2.4	2.3	2.5
Massachusetts	0.2	0.2	0.3	0.6	1.0	1.2
New Hampshire	0.7	0.3	1.0	1.4	2.0	1.2
Rhode Island	0.0	0.0	0.0	0.5	0.6	1.1
	PADD I-B					
Delaware	0.0	0.0	0.1	0.3	2.0	1.9
Maryland	0.0	0.3	1.7	1.7	2.0	3.4
New Jersey	0.0	0.1	0.1	0.1	0.3	0.5
New York	0.1	0.0	0.3	0.7	1.2	1.4
Pennsylvania	0.0	0.0	0.2	0.3	1.0	1.2
	PADD I-C					
Florida	0.0	0.2	0.8	2.4	4.5	5.6
Georgia	0.0	0.1	0.4	1.4	2.4	4.9
North Carolina	0.0	0.2	0.0	0.7	1.8	4.0
South Carolina	0.1	0.2	0.7	1.3	3.6	5.0
Virginia	0.0	0.6	0.7	2.0	3.0	3.9
West Virginia	0.0	0.3	1.0	1.5	2.5	4.7
	PADD II					
Illinois	0.1	0.2	0.3	0.6	1.4	2.0
Indiana	2.1	2.2	2.9	3.1	4.9	7.2
Iowa	0.0	0.1	0.3	0.8	1.7	2.6
Kansas	0.0	1.3	0.8	1.2	3.3	7.5
Kentucky	0.4	0.5	1.3	4.2	9.2	10.2
Michigan	4.1	4.9	4.9	6.1	7.2	7.3
Minnesota	0.0	0.1	0.0	0.0	0.6	1.2
Missouri	0.0	0.3	0.5	0.9	2.4	3.5
Nebraska	0.0	0.1	0.0	0.7	2.3	2.6
Ohio	1.5	1.4	1.8	3.0	4.4	5.8
Oklahoma	0.0	0.4	0.6	1.1	4.7	6.7
South Dakota	0.0	0.1	0.0	0.1	0.4	1.7
Tennessee	0.4	0.6	0.9	3.7	8.4	11.1
Wisconsin	0.1	0.0	0.0	0.1	0.1	0.2
	PADD III					
Alabama	0.0	0.4	0.6	1.9	2.7	3.0
Arkansas	0.0	1.1	1.1	4.4	8.3	11.5
Louisiana	0.1	0.1	0.8	2.0	6.3	8.0
Mississippi	0.0	2.2	2.8	4.0	9.0	9.6
New Mexico	0.0	2.2	2.3	2.1	5.6	9.5
Texas	0.1	1.3	2.5	6.4	11.0	14.1
	PADD IV					
Colorado	0.0	0.0	1.4	2.8	5.5	9.0
Idaho	0.0	0.5	1.2	3.4	6.4	7.8
Montana	0.0	0.0	0.1	2.5	2.4	3.7
Utah	0.0	0.0	0.2	3.3	5.6	4.8

Table 9-9 *(continued)*

State	Hypermarket Share within State (%)					
	1997	1998	1999	2000	2001	Jun-02
Wyoming	0.0	0.0	0.3	0.7	2.8	4.5
	PADD V					
Arizona	0.0	3.7	5.4	5.4	7.4	8.9
California	0.0	1.1	2.7	3.6	5.2	5.7
Nevada	0.0	0.7	2.4	2.3	8.4	8.8
Oregon	0.0	0.0	0.2	1.2	3.6	6.3
Washington	0.0	1.2	3.0	5.1	11.2	13.9

Source: *NPD Group Motor Fuels Index* (annual). NPD data used under license.

Note: Source does not report for Alaska and Hawaii. Other omitted states reported no hypermarkets in any year.